I. Introduction

Q. Please state your name and qualifications.

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

Q. What is the purpose of this proceeding?

A. This proceeding has its roots in events that began in the early 1990s, shortly after the Commission adopted least cost planning as the process and methods by which Oregon utilities would select the future resources they would use to serve customers. The process the Commission ordered was one of broad inclusion, allowing everyone with an interest the opportunity to understand and provide input on a utility's resource decisions. The method was one of evaluating both supply-side and demand-side resources on a consistent basis and considering both the internal and external costs of resource decisions.

Using the least cost planning process and methods, PGE filed with the Commission in 1992 a plan recommending that we phase out our Trojan generating plant over four years, replacing it with other resources which had a projected lower cost than Trojan. This recommendation had wide support among a large group of participants in our process. When Trojan's condition, and economics, worsened at the end of 1992, PGE quickly analyzed whether immediate closure would increase the benefit to customers over phase-out and, because it did, we closed the plant in January 1993. The Commission ultimately acknowledged both the phase-out and subsequent immediate closure decisions as producing lower costs for customers than continued Trojan operation. Throughout the planning process, PGE assumed that, if closure was the most economic choice for customers, PGE

could recover its remaining investment in Trojan because this sunk cost would exist given either course of action.

Late in 1993, PGE filed a general rate case, UE 88, to adjust our revenue requirement for this significant resource decision. We knew that processing the case would require many months and intended that the rates take effect January 1995. The case's revenue requirement included return of and on PGE's investment in Trojan over the 17 years remaining under the nominal depreciation life the Commission had set for Trojan when it entered service. Filing this way best matched the costs and benefits of the least cost resource decision for customers and did not harm PGE because, as we and the Commission understood Oregon law at the time, the Commission could allow us to recover both return of and on this investment retired to produce economic benefit to customers.

Following the Commission's decision in March 1995, several parties argued to the Oregon courts that Oregon law does not allow return on a utility's investment in a plant it has retired for economic reasons. The Court of Appeals ultimately agreed in 1998 and remanded UE 88 to the Commission. The Oregon Supreme Court accepted the case for further review. In 2000, while that appeal was pending, PGE, CUB and Staff jointly proposed to the Commission, UM 989, a way to eliminate PGE's remaining investment in Trojan, matching this amount owed PGE with a somewhat smaller amount PGE owed customers. The Commission's order approving this proposal was also appealed and, in 2003, remanded to the Commission. Our opening brief discusses both remand orders. The Commission considers the scope of this phase of the process to determine what rates it would have set in UE 88 and whether it would have approved the proposal in UM 989, had it known that Oregon law precluded it from setting rates including a return on investment in

a generating plant retired for economic reasons. If the Commission finds that it would have set lower rates, it will next determine the amount, if any, of refunds to customers. We are engaged here in presenting facts and arguments regarding what the Commission would have done ten and five years ago in UE 88 and UM 989, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present PGE's case regarding the questions this remand proceeding requires the Commission to answer. Relying on the records originally developed in UE 88 and UM 989 and the testimony we file here, I explain what PGE would have urged the Commission to do in the dockets now on remand. What we propose assumes everyone knew throughout the 1990s that Oregon law precludes a Commission from allowing utility investors a return on money invested in a generating plant that is retired because it is more economic for customers to replace the plant's output than for the utility to continue operating it. The prohibition exists even though retirement before the end of the Commission-approved depreciation life produces lower costs for customers than continued operation.

Had the Commission known of this interpretation of Oregon law, it would have had many choices available to it. PGE has identified choices that are consistent with the overarching goal of regulatory policy, that promote analysis and action by utilities to achieve the least cost for customers, that allocate utility costs to customers fairly over time, and that maintain a utility's ability to access capital so that utility service remains safe and adequate. Choices other than those we present here likely exist. But such choices are poor if they do not serve these goals and objectives. Both then – in 1995 and 2000 – and now, choices that do not

serve the goals and objectives of regulation would have resulted and will result in regulation that does not serve customers.

PGE's evidence shows that, had the Commission known of the constraint Oregon law places on its ability to spread the un-depreciated cost of generating plant retired to achieve lower costs:

- In 1995, the Commission would have found fair and reasonable rates at least as high, if not higher, than the rates approved in Docket UE 88, Order No. 95-322; and
- In 2000, the Commission would have approved the stipulation presented to it and the proposed $10 million rate reduction as fair and reasonable and a proper exercise of its discretion in Docket UM 989, Order No. 00-601, because amounts owed PGE at that time would have exceeded the customer credits used as an offset. This would have produced economic as well as other benefits to customers from the resolution of the issues.

I explain the regulatory policy supporting PGE's position and summarize the quantitative analysis underlying it. Our position accepts, for purposes of this policy and quantitative review that the underlying legal theories comply with statutory and constitutional requirements.[1]

Q. How is your testimony organized?

A. My testimony is organized into six sections.

[1] In doing so, PGE is not waiving any legal arguments regarding the availability of refunds for UE 88, UE 93, or UE 100, or the consideration of allegedly "excess" rates in UE 88, UE 93, and UE 100 in the Commission's evaluation of UM 989. Nor is PGE addressing, or waiving, our policy arguments regarding why, even if refunds or adjustment of PGE's balance sheet for past excess rates were legally supportable, such steps would be inadvisable from a regulatory policy perspective and the Commission could exercise its discretion to reject such actions. It is our understanding that we can make our case regarding the advisability of refunds in phase II of this proceeding.

- In Section II, I briefly review the regulatory and ratemaking context for this remand proceeding;
- In Section III, I explain the approach we followed to reach our position;
- In Section IV, I review the reasons for each of the factual or policy decisions from the remanded cases that PGE examined in developing our position;
- In Section V, I explain our position, using the methodology of Section III and certain of the building blocks of Section IV; and
- In Section VI, I summarize the other testimony PGE is presenting.

Q. Are there any explanations necessary with respect to PGE's testimony in this case?

A. Yes, there are two contextual explanations. The first explanation concerns the amount of general ratemaking and background information we are presenting in this docket. Our review of such fundamentals does not imply a belief that the Commission, or the parties, require education in such matters. Indeed, much of it is what any participant in the economic regulation arena learns in his or her first rate case and never consciously thinks about again. But what we "veterans" take for granted, can leave a record that is difficult for a reviewing court to understand. We believe that the unusual nature of these remanded rate determinations requires that we provide a foundation that would not otherwise be necessary.

The second explanation concerns the difference between revenue requirement and rates. The remand orders refer to rates. As the scoping ruling indicates, rates are the result after the Commission determines revenue requirement, allocates that revenue requirement across all of the utility's tariffs (rate spread) and among the billing determinants within each tariff (rate design) and, for those billing determinants based on energy usage, applies the retail load forecast to determine a per kWh rate. For purposes of our quantitative analysis in this

phase, we stop at the first step of this process – revenue requirement – because the remand orders suggest no change in rate spread and design determinations.

II. Regulatory and Ratemaking Context

Q. What is the overarching regulatory policy that guides the Commission in this remand proceeding?

A. All of the Commission's decisions and choices are guided by its delegation of authority from the Legislature, stated in ORS 756.040. That delegation contains two goals that relate to treatment of customers and two that relate to treatment of investors:

<u>Customers</u>

- Adequate service
- Fair and reasonable rates

<u>Investors</u>

- Returns commensurate with the returns on investments in comparable businesses
- Confidence in financial integrity, maintenance of credit and attraction of capital.

The delegation statute requires the Commission to "balance the interests of the utility investor and the consumer in establishing fair and reasonable rates." ORS 756.040. I believe this phrase is somewhat misleading to the extent that one could infer from it an opposition of investor and customer interests, with any gain to investors an equal loss to customers, and vice versa. Rather, the goals for customers and investors are inter-related and reinforcing: A utility cannot provide adequate service without the ability to attract capital. This is typically not in dispute in a rate-setting process.

For example, few would argue that a utility can attract capital if the rates set by the Commission do not allow it to pay the interest on its outstanding debt as such interest becomes due. Indeed, to borrow additional money on reasonable terms requires that a utility have the financial strength – created by the opportunity to earn and retain income over and

above interest payments – to make all future interest payments. Several credit rating agencies exist to inform potential lenders of the likelihood of repayment. The agencies' assessments influence access to and the cost of debt. Borrowing becomes significantly easier and less expensive when a firm has "investment grade" ratings. Accordingly, rate decisions that permit a utility to reach and maintain financial coverage ratios sufficient for investment grade debt ratings are usually not controversial. Above investment grade, however, the Commission must weigh the benefit to customers – in the form of reduced borrowing cost – with the cost to customers – in the form of higher rates today. It is this decision that is the balance between customers and investors.

Q. Is there another "balance" that is an important guide to ratemaking decisions?

A. Yes. The capital intensive nature of the utility business means that many of the costs incurred are large, lumpy expenditures for physical or intangible assets that produce benefits for many years. The Commission is constantly balancing the interests of today's consumer with the interests of tomorrow's consumer. To achieve the best allocation of society's resources over time, someone making the choice to use electricity today should pay roughly what it costs today, not significantly more and not significantly less. The Commission must spread costs fairly across "generations" of customers to achieve this result. It does so most often in the context of setting depreciation rates for all utility property, a task specifically given it by the Legislature. It engages in this balancing for other matters as well, such as amortization and accounting decisions.

This balancing of consumer interests across time relates to the balancing between consumer and investor interests. Rates set too low today to attract capital will make future

capital costs – and, thus, future rates – higher and may cause degradation in future service. Current customers will benefit at the expense of future customers.

Q. Are there any rules regarding how the Commission engages in both balancing investor and consumer interests and balancing consumer interests across time?

A. Very few. The statute at the heart of this remand is one of those few. In general, the Commission has broad discretion to fashion the balances that it finds most suitable to the facts at hand. This excerpt from the UE 88 order is typical:

> "Staff notes that the Commission has broad discretion when it comes to ratemaking. As the Oregon Supreme Court said, 'The [Commission] appears, therefore, to have been granted the broadest authority – commensurate with that of the legislature itself – for the exercise of [its] regulatory function.' *Pacific N.W. Bell v. Sabin*, 21 Or App 200, 214 (1975)." Order No. 95-322 at 61.

The Legislature's – and, thus, the Commission's – authority is constrained only by the Constitution. The seminal case of Federal Power Commission v. Hope National Gas Co., 320 U.S. 591 (1944) explained that the constitutional protections are tested against the end result of a rate order. A later Supreme Court case – Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989) – explained the "end result" test as follows:

> "[I]t is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unreasonable judicial inquiry is at an end. The fact that the method employed to reach that result may contain infirmities is not then important." 488 U.S. at 310

Worth noting is Duquesne's finding that state ratemaking authority cannot "arbitrarily switch back and forth between methodologies in a way which [requires] investors to bear the risk of bad investments at some times while denying them the benefit of good investments at other times" without raising serious constitutional questions. Duquesne, supra, 488 U.S. at 315.

Any exercise of the Commission's broad discretion as it sets rates, within its statutory delegation and subject to the U.S. Constitution's requirements on the end result, will have consequences for the future. The objective of regulatory policy is to find that exercise of discretion the consequences of which move the Commission closer to, not farther away from, its overarching goal of securing adequate utility service for consumers at fair and reasonable rates. To simplify its task, the Commission adopts certain frameworks and conventions.

Q. What do you mean by frameworks?

A. Integrated resource planning (IRP), or least cost planning (LCP) as it was known when the Commission first issued the order adopting it, is an example of a framework - and a very important one to consumers generally and to this proceeding. In 1988, the Commission determined that the process by which a utility chose its generating resources was a critical component of whether the Commission could find rates based on those decisions to be fair and reasonable. In particular, the Commission found that allowing public review of and input to utility resource decisions would improve the quality of such decisions. The Commission acknowledges resource decisions using the IRP framework and such acknowledgements affect subsequent ratemaking decisions. "Although a decision made in the LCP process does not guarantee favorable ratemaking treatment, the process should provide some guidance to a utility." Order No. 89-507 at 3.

Q. What do you mean by "conventions?"

A. By the term "convention," I mean "the way we usually do things unless there is good reason, determined by the Commission's overarching goal, not to." The use of cost as the basis of setting rates is a convention. Nothing requires that the Commission use cost. But it

is hard to think of a basis to use for ratemaking that is easier to determine and understand than cost and, thus, typically, economic regulation relies on cost. The choice of a test period over which to assess costs and revenues for purposes of determining rates is a convention.

Calculating interest costs and equity costs (net income) on the basis of rate base is also a convention. For some water utilities, this does not work at all because the utility plant they use is fully depreciated. In those instances, the Commission does not use rate base to determine the cost of debt and equity for rate-setting. Including purchased power in revenue requirement at the cost of the contract is another convention.

If any of these conventions has consequences that move the Commission further away from its goal of adequate service at fair and reasonable rates, the Commission has the broad discretion – noted above – to change the convention. A good example of this is the policies the Commission adopted in the early 1990s to encourage utilities to acquire demand-side resources – customer energy efficiency measures – to help offset future needs for generation. Mr. Dahlgren, PGE Exhibit 6100, Section II**,** discusses these policies.

These conventions not only change over time, but there is considerable diversity of conventions across regulatory jurisdictions. How one jurisdiction calculates various costs for ratemaking purpose may differ significantly from the conventions used in another jurisdiction. None of the variations are wrong; they are simply different.

Q. Is there a convention that particularly requires examination in this proceeding?

A. Yes. In Docket DR 10, the Commission developed the convention that it would use in setting rates for a utility that had retired a generating plant to achieve least cost power supplies for its customers. In brief, this convention was that a utility could recover its un-depreciated investment in a generating plant retired prior to the end of its nominal

depreciation life, if it established six facts and met six conditions designed to permit a conclusion that the retirement produced a "net benefit" for customers. Mr. Dahlgren describes the convention in PGE Exhibit 6100, Section III. The Commission applied this convention, with some refinement and further detail, in UE 88. The primary refinement of UE 88 was the conclusion that the net benefits test would consider the costs and benefits of retiring and replacing the output of that generating plant from a ratemaking perspective in addition to a planning perspective. The ratemaking perspective, eliminated from the calculation future costs found to be imprudent.

In developing this convention, the Commission assumed that it could set rates to include a return on any un-depreciated balance of the retired generating plant that the Commission did not allow the utility to recover immediately. The Commission did not contemplate that its decision regarding how to spread the un-depreciated plant costs to customers over time could also result in harm to utility investors. The net benefits calculation did not account for this; nor did the Commission's six conditions. Because of the Court of Appeals ruling, the Commission must develop, and apply, a new convention for the recovery by a utility of its remaining investment in a generating plant that it retires before the end of the plant's original depreciation life to achieve least cost for customers.

Q. How do the "overarching regulatory policy," frameworks and conventions you have discussed relate to PGE's position in this remand proceeding?

A. PGE's position rests on the assumption that, in this remand proceeding, the Commission will exercise its discretion regarding:

- The application of ratemaking conventions,
- Decisions on factual issues, and

- Policy choices

to achieve the overarching goal of regulatory policy and continue to support the frameworks – including IRP – it has developed. According to the Court of Appeals, the Commission may not set rates based on calculations that include return on the un-depreciated investment in an economically-retired plant that is being recovered over time, but the Legislature does not otherwise direct how the Commission should have set rates in UE 88 or UM 989. The overarching regulatory policy set forth in the Commission's delegation of authority applies and the Commission has broad discretion in how it exercises that authority.

Q. Is there anything unique about this proceeding?

A. Yes, the remand nature of this proceeding makes it unique. The Commission is not setting rates that will be in effect in 1995. Nor is it setting rates that will be in effect in 1996, 1997, 1998, 1999, or 2000. Instead, the Commission is engaged in setting rates for periods in which those rates cannot possibly take effect. Neither PGE nor customers can change past decisions that were made on the basis of these rates. The ratemaking decisions the Commission makes here can take effect only in the future. Based on the policy and future rates that emerge from this proceeding, PGE and its customers can only affect future decisions.

III. PGE's Approach

Q. What approach did PGE follow in reaching your position in this remand proceeding?

A. We applied three questions to serve as the criteria by which we could test the regulatory policy strength of our position. Then we identified the factual and policy decisions made in UE 88 that require re-examination in light of the Court of Appeals interpretation of Oregon law. Our position is a set of changes that best meets the criteria.

Any rate decision is the sum of a myriad of interconnected, factual, and policy decisions. It is hard enough to steer such decisions to rates that meet statutory and constitutional tests and produce consequences that work toward achieving the overarching goal of regulatory policy in the future when in a normal general rate proceeding. A retrospective review such as this only increases the difficulty. In such circumstances, developing and applying criteria helps discipline and manage the large number of possible paths.

Q. What criteria did PGE develop for this proceeding?

A. We believe that, had the Commission known in deciding UE 88 and subsequent cases that, if it spread the recovery of Trojan's un-depreciated balance over time, then it could not allow PGE to earn a return on the balance, its factual and policy decisions in UE 88 and ultimately UM 989 would have been guided by the answers to these questions:

1. Does this decision encourage electric utilities to analyze and make resource decisions that will yield "an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"[2]
2. Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears

[2] OPUC Order No. 89-507, page 2.

an inequitable burden of the costs or receives an inequitable share of the benefits?

3. Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

Q. Please explain the first criterion: Whether this decision encourages electric utilities to analyze and make resource decisions that will yield "an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest."

A. First and foremost, this criterion recognizes the importance to Oregon of least cost planning. As Mr. Dahlgren explains, the IRP process is designed to produce least cost resource decisions, over time, for customers. At times, achieving the least cost set of resources for customers may require not only the addition of new resources but the retirement of some existing resources, the incremental costs of which exceed the costs of replacements. The Court of Appeals interpretation has created a barrier to such least cost resource realignments, however. If a utility cannot earn a return on the plant that it has retired to achieve least cost for customers, and the Commission does not allow the utility immediately to recover the remaining plant investment so that the utility's investors remain whole, then it has little incentive to take this resource action. The action would produce negative results for the utility, rather than positive or even neutral results. The disincentive worsens if the Commission does not otherwise set rates to allow a utility in this situation the revenues sufficient to maintain its financial health and credit ratings over time. Oregon utilities would be motivated to continue operating resources for their nominal depreciation lives, rather than their economically useful lives, as measured by least cost to customers over time.

This incentive would work against the least cost planning framework that is so important to achieving safe and adequate service for customers at reasonable rates.

The first criterion also recognizes the soundness of a regulatory approach that encourages utilities to act in the interests of customers and the public, rather than punishing them for not doing so. Mr. Dahlgren discusses an example of such encouragement: the set of policies the Commission adopted to encourage utilities to invest in demand-side resources (energy efficiency). PGE Exhibit 6100, Section II. Instead of adopting these policies, the Commission could simply have told utilities it would disallow any supply-side costs it determined the utility could have avoided by investing in demand-side resources instead. The difficulties with the punitive approach, however, are several. First, it is much easier to identify and reward affirmative actions a utility has taken. Such actions require no speculation. They are measurable. Second, too much use of cost disallowance can threaten a utility's financial integrity and ability to attract capital on reasonable terms, and thus threaten the Commission's ability to achieve the goal of adequate service at fair and reasonable rates in the future. Last, based on my experience observing the effects of regulatory choices over 20 years, rewards can motivate even at the individual level. Rewards encourage individual actions, because individuals can understand how their actions will help the utility achieve better financial results and may be mirrored by individual incentive programs. Utilities cannot so align individual financial results with disallowances.

Q. Please explain the second criterion: Whether this decision equitably allocates the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable burden of the costs or receives an inequitable share of the benefits.

A. This criterion expresses the balance of customer interests I discussed in Section II of my testimony. It is a well-understood principle of economics that consumers will make the best decisions about consumption if the price paid for such consumption at any given time is as close to the true cost as possible. A significant misalignment of costs and benefits of a utility resource decision would violate this economic principle. The Commission routinely applies this criterion in determining the period over which utilities will recover the cost of assets (depreciation or amortization) and expenses (e.g., debt refinancing costs) incurred to produce future benefits, as well as the period over which customers will receive the benefit of utility cost savings (e.g., lower than expected variable power costs) or revenue credits (e.g., sales for resale, property sale gains).

Q. Please explain the third criterion: Whether this decision preserves the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised.

A. As with the first two, this simply states as an explicit question matters I discussed in Section II. Although aspects of this criterion relate to constitutional requirements, it has practical implications for customer needs as well. All investors, debt or equity, care about the regulatory environment into which they are investing. Regulatory policies that are understandable, fair, and focused on the long-term, decrease the perceived investment risk. For example, investors perceive as understandable and fair regulatory policies that allow recovery of prudently-incurred costs. Regulatory policies that put prudently-incurred costs at risk to events or outcomes outside of the utility's control would be perceived the opposite. Decreased risk increases the availability of capital and decreases its cost; increased risk has

the opposite effect. Thus, this criterion is important for investors and customers over time. What appears cheap today may be costly tomorrow.

Q. Are there any other considerations that are important guides to ratemaking decisions?

A. Yes. As a general matter, customers value and Commissions work to achieve rates that are relatively stable over time, with predictable movement. For example, customers typically would prefer a series of small increases, anticipating higher costs over time, than a larger one-time increase. Many consumption decisions relate to equipment or processes that are hard to adjust immediately but that a customer can modify if given some time to do so. For example, assume a large business customer with significant capital investment in equipment and complex manufacturing processes. This customer may be able to reduce its energy consumption over time through changes to equipment, processes or both but it probably cannot make such changes quickly in response to a one-time large increase in the cost of electricity. Spreading such an increase over time in rates that anticipate the higher costs that are coming allows customers to make such equipment and process changes. Achieving rate stability and predictability need not harm customers or the utility as long as the Commission recognizes in setting rates the time value of any rate changes not exactly aligned with the underlying cost changes.

IV. Building Blocks

Q. Please summarize the UE 88 factual and policy decisions PGE is suggesting the Commission might have made differently had it known of the Court of Appeals ruling.

A. The factual and policy decisions we are suggesting the Commission might have made or made differently are the following:

- The period over which it ordered PGE to amortize its un-depreciated Trojan investment (Subsection A);
- The required return on common equity and capital structure (Subsection B);
- The calculation of the net benefits test and application of the resulting net benefit (Subsection C);
- The classification of certain components of Trojan as plant-in-service (Subsection D);
- The amortization period for certain liabilities on PGE's balance sheet owed to customers as of March 1995 (Subsection E);
- The recovery in 1995 of all forecasted 1995 net variable power costs (Subsection F); and
- The inclusion in rates of all of PGE's interest payment costs, regardless of whether the underlying debt relates to un-depreciated Trojan investment (Subsection G).

For each of these factual or policy decisions, I discuss below why the Commission should revisit it, and the outcome or range of outcomes PGE believes the Commission would have adopted and why, including the reasons for changing a ratemaking convention if necessary.

A. Amortization Period

Q. Why should the Commission revisit its decision in UE 88 regarding the period over which PGE should amortize its un-depreciated investment in Trojan?

A. The Commission should revisit this amortization decision because it relies completely on the Commission's assumption that it could allow PGE to recover its costs of equity and debt capital associated by allocating to customers over time the un-depreciated investment. The Court of Appeals ruling that the Commission could not allow PGE a return on the Trojan investment requires that the Commission revisit the period of amortization.

Applying the simple principle that a dollar received in the future is not worth the same as a dollar received today, any delay in PGE's receipt of this investment is a quantifiable decrease in the investment for which the Commission would be granting recovery. The PGE Panel[3] calculated that leaving the amortization period for Trojan's un-depreciated investment at 17 years without a return is the same as an initial disallowance of $182 million. PGE would have experienced an asset write-off of $149 million, lowering its retained earnings in 1995 from $136 million to $46 million.

Q. How was the amortization period for the un-depreciated balance of Trojan investment chosen?

A. The amortization period chosen resulted from the application of ratemaking convention, although the Commission did not discuss this explicitly. If a utility incurs a particular cost to produce a benefit such as lower future costs, the Commission typically sets the amortization of the up-front cost over the period that customers will experience the lower costs. Examples

[3] The PGE Panel is Jay Tinker, Stephen Schue, and Patrick Hager who prepared and appear in PGE Exhibit 6200. That exhibit provides the quantitative analysis PGE is presenting in this docket, other than that quantification done in support of return on equity.

of this convention include the Commission's treatment of amounts incurred to replace higher cost debt with lower cost debt, and its recent decision on treatment of costs incurred to reserve natural gas pipeline space at a low price for eventual use by Port Westward. Order No. 95-322 reflects this convention in its choice of the same period for amortization of Trojan as the 17-year period of the cost-benefit analysis supporting Trojan's closure.

Q. Does good reason exist to change this convention here?

A. Yes, good reason exists for the Commission to shorten the recovery period. As noted above, a 17-year amortization period under the Court of Appeals interpretation of Oregon law results in a disallowance to PGE of $182 million and a write-off of $149 million. Mr. Hager testifies regarding the negative effects this outcome would have had on PGE's ability to attract capital and cost of capital. (PGE Exhibit 6400, Section III). As I discuss in Section IV.E. below, the Commission could have exercised its discretion regarding other elements of ratemaking to achieve the same inter-generational result for customers as the 17-year amortization period achieved but avoid this large financial loss to PGE.

Q. What amortization periods should the Commission consider in deciding this remand proceeding?

A. The Commission should consider a one-year amortization period. We believe it most likely that, had the Commission decided to select a rapid recovery, it would have chosen a one-year period. To prevent any diminution in the amount of un-depreciated investment the Commission found that PGE should recover, the collection period would have needed to be one day. This is not practical. Nor would a one-day recovery be fair between customers, whose usage as of that day may be other than their normal usage. One year captures the

monthly and seasonal variations in customer usage and roughly allocates the cost according to usage patterns.

Q. What outcome or range of outcomes results from revisiting the decision regarding amortization of PGE's un-depreciated Trojan investment?

A. A decision regarding the amortization period for PGE's un-depreciated investment in Trojan affects the UE 88, UE 93, and UE 100 rate periods as well as UM 989. Briefly, a one-year amortization would significantly increase the UE 88 and UE 93 (first four months) revenue requirements and lower revenue requirements in the last part of the UE 93 rate period and during the entire UE 100 rate period. In 2000, PGE would have had no un-depreciated Trojan investment on its balance sheet. On the other hand, the large disparities in rates across the rate periods would require that the Commission evaluate whether the UM 989 result remains reasonable. One method of doing so would be to compare the amounts owed PGE from the UE 88 and first part of the UE 93 rate periods to amounts owed customers from the last half of the UE 93 and UE 100 rate periods. Using this method, the net present value difference in amounts owed PGE and amounts owed customers supports the stipulations approved in UM 989. The PGE Panel details these outcomes in PGE Exhibit 6400, Section II.

B. Required Return on Equity and Capital Structure

Q. Why are you suggesting that the Commission might have made a different decision with respect to the level at which it established PGE's required return on equity (ROE) in UE 88?

A. The Commission's delegation of authority from the Legislature requires that it, among other things, establish a return to the equity holder that is commensurate with the return on investments in other enterprises having corresponding risks. Both when the Commission decided UE 88 and now, few utilities faced or today face the risk of a major loss to their equity holders caused by the early retirement of a generating plant to produce net benefits for customers. PGE's investors face more risk than their counterparts and, thus, PGE's cost of capital is likely higher than for comparable utilities that do not face such a regulatory environment. See generally Makholm and Blaydon, PGE Exhibits 6500 and 6600. The Commission would have considered this greater risk in determining PGE's required return on common equity in UE 88, UE 93, and UE 100.

Q. Was the Commission's determination of PGE's required return on equity in UE 88, UE 93, or UE 100 the result of a convention?

A. No. To determine required return on equity, the Commission typically relies not on convention but on economic models, such as the discounted cash flow (DCF) or capital asset pricing (CAPM) models.

Q. What required return on common equity should the Commission consider in deciding this remand proceeding?

A. PGE Exhibit 6400 supports increases in PGE's required return on equity ranging from 25 to 150 basis points. A basis point is one-hundredth of a percent. The lower end of the range represents the increased risk to investors in Oregon utilities related to the Court of Appeals interpretation of Oregon law and a short amortization period. The higher end of the range relates to risk investors would perceive if the system of economic regulation in Oregon forced utilities to receive, over an extended period with no return on investment, their un-

depreciated investment in generating plants economically retired before the end of their depreciation lives.

Q. What outcome or range of outcomes results from re-determining PGE's required return on equity?

A. Applying the range to UE 88, UE 93, and UE 100 results in revenue requirements $17 million to $102 million higher than the Commission would otherwise have found. The PGE Panel demonstrates this at PGE Exhibit 6200, Section III**.**

Q. Does similar reasoning underlie your suggestion that the Commission might have, for purposes of ratemaking, established a different capital structure for PGE?

A. Yes. The Commission's delegation of authority also requires that the rates be sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital. Although a higher ROE that provided PGE an opportunity for greater net income would contribute to financial integrity, use of a hypothetical capital structure with greater amounts of equity would also accomplish this result.

Q. Was the Commission's determination of capital structure for PGE in UE 88, UE 93 and UE 100 the result of applying a convention?

A. Yes. Historically, the Commission has used a utility's actual capital structure during the one-year test period it is using to set rates, if this is known. In other words, for a utility such as PGE, the Commission would use PGE's forecast capital structure for the test year. Sometimes the Commission cannot know a utility's actual capital structure for utility service because the utility has significant non-utility activities within its business structure. In such cases, the Commission has used a hypothetical capital structure.

Q. Does good reason exist to use a hypothetical capital structure for PGE during the UE 88, UE 93, and UE 100 rate periods, rather than the actual capital structure used by the Commission in its initial decisions?

A. Yes. Depending on the other decisions the Commission decides that it would have made. As Patrick Hager explains in PGE Exhibit 6400, Section III, a Commission decision to amortize Trojan's un-depreciated balance over 17 years would significantly worsen the financial ratios by which credit rating agencies decide whether a utility is credit-worthy. A hypothetical capital structure could help restore the ratios to levels that will help attract future capital. PGE Exhibit 6401.

Q. What outcome or range of outcomes might result from re-visiting this issue?

A. Use of a hypothetical capital structure with greater amounts of equity would increase UE 88, UE 93 and UE 100 revenue requirements, all else being equal. The PGE Panel does not quantify these outcomes because they are similar to the outcomes PGE quantifies for a higher required return on equity.

C. Calculation and Application of Net Benefits

Q. Which factual and policy decisions in the calculation of the net benefits test are you suggesting that the Commission revisit and why?

A. PGE suggests that the Commission revisit in this remand proceeding one factual and one policy decision included in the UE 88 calculation of the net benefits test.

The factual decision relates to costs included on the replacement resources side of the net benefits test comparison. In the UE 88 calculation of the net benefits test, the Commission included recovery by PGE of our Trojan investment over 17 years, with a return on the un-

depreciated balance, matching the recovery of and return on Trojan assuming continued operation. Under the Court of Appeals interpretation, this must change. As explained above (and, in more detail in PGE Exhibit 6200, Section IV), whether amortization of the un-depreciated balance is over one year or 17 years, excluding any return on investment effectively reduces the cost to customers, and thus increases the benefit of closure. All else being equal, this will lower the cost of the replacement resources side of the net benefits test, increasing the net benefit to closure. The PGE Panel calculates that adjusting the net benefits test for the Court of Appeals interpretation results in a net benefit for closure of $-4 million assuming a one-year amortization period and $155 million assuming a 17-year amortization period. This adjustment is consistent with and required by the Commission's methodology.[4]

The policy decision relates to costs included on the continued operation of Trojan side of the net benefits test comparison. In UE 88, the Commission exercised its discretion to exclude from the costs of Trojan's continued operation amounts PGE would have incurred to replace Trojan's steam generators. This exclusion did not rely on any finding of imprudence by PGE; indeed, the Commission explicitly found that PGE had acted prudently with respect to both the purchase and maintenance of the steam generators that would require replacement. Order No. 95-322 at 3. Nor did the Commission find that PGE could have operated Trojan for its remaining license life without new steam generators. Nonetheless, the Commission ultimately decided in the context of UE 88 to allocate the consequences of the steam generators' problems to PGE, stating that:

[4] As Order No. 95-322 explains, the net benefit test is a scenario comparison: the future costs of continued Trojan operation compared to the future costs of other resources. Footnote 16 on page 32 of that Order states: "Under the net benefits analysis, sunk investment cost is added to the cost of each option. . . . . The net benefit treatment of sunk investment cost does not . . . change the difference between the costs of any two options . . . ." Had the Commission known of the Court of Appeals decision, it could not have made this statement.

> "Although PGE's behavior was not faulty, PGE and the ratepayers are the only two parties to whom we can assign or impute steam generator costs. As between those two parties, PGE is better situated to recover its costs from the manufacturer of the steam generators. Moreover, it is fair that shareholders bear some of the consequences of management investment decisions." Order No. 95-322 at 3.

Order No. 95-322 is clear that the Commission's decision to exclude the steam generator replacement costs from the continued operation scenario in the net benefits test was an exercise of its discretion. It noted PGE arguments against the exclusion and emphasized that its decision on cost recovery was not meant to act as precedent for any future outcome.[5] We suggest here that, had the Commission known that the Court of Appeals would interpret ORS 757.355 to prohibit rates that included a return on the remaining Trojan investment, the Commission might not have exercised its discretion on this issue as it did. It might not have found it "fair" to allocate this cost to shareholders. No convention dictated the original result and none inhibits a different decision now. Indeed, good regulatory policy supports reversing this UE 88 decision. Holding investors solely responsible for prudently incurred costs shifts significant risk to such investors. As Dr. Makholm explains, (PGE Exhibit 6500) one of the most fundamental investor expectations about a regulator is that the regulator will allow the utility an opportunity to recover prudently incurred costs through its rate decisions. The UE 88 net benefits test decision on the steam generators violates this expectation, raising questions for the future, even though the Commission attempted to minimize the effect by stating it would make such decisions on a case-by-case basis. Given the risk that the Court of Appeals interpretation has added to Oregon's regulatory environment, it makes little sense to

[5] Subsequent to UE 88, PGE resolved its claims against Westinghouse. The settlement of that litigation resulted in a payment of about $4 million by Westinghouse, which PGE credited to customers in the UM 989 stipulation. The $187 million excluded by the Commission from the net benefits test dwarfs the amount PGE was ultimately able to recover from the manufacturer.

add more risk by preserving this decision to exclude steam generator replacement costs from the net benefits test calculation.

Q. Might the Commission have made different decisions regarding other inputs to the net benefits test used in UE 88?

A. Yes. Order No. 95-322 discusses and resolves a number of inputs to the net benefits test for which competing views were presented. Most of the Commission's decisions chose inputs that lessened the amount of net benefit created by early retirement, creating a conservative result. Were the Commission to revisit any of these decisions, the amount of net benefits from retirement would increase. Although PGE is not presently suggesting that the Commission needs to engage in this retrospective review of the disputed inputs to the net benefits test, we ask that the Commission recognize the conservative quality of the original net benefits result in determining how to apply the net benefits result in this remand proceeding.

Q. What is the effect on the result of the net benefit test of the factual and policy decisions you suggest that the Commission re-visit?

A. Adding the steam generators to the cost of continued operation increases the net benefits of closure by $183 million, all else being equal. With both changes I discuss above, the PGE Panel estimates net benefits ranging from $179 million, assuming one-year amortization of Trojan's un-depreciated balance, to $338 million assuming 17-year amortization.

Q. Why should the Commission revisit its application of the result of the net benefits test?

A. The Commission should revisit the result of its application of the net benefits test because, in UE 88, it considered only how it might apply a negative net benefit. The factual and policy decisions made in calculating net benefits for UE 88 resulted in a negative net benefit of $27

million (pre-tax).[6] Thus, the Commission's regulatory policy analysis considered the net benefits test only in the context of "a tool to determine where ratepayers are held harmless for imprudent operation or management of Trojan, and to share costs between ratepayers and shareholders on that basis." Order No. 95-322 at 2.

Order No. 95-322 does not discuss how the Commission might have exercised its discretion had the result of the calculation of the net benefit test been the positive $179 million to $338 million I note above. These are significant net benefits to customers that the Commission would want to encourage utilities to look for, even with the ruling that investors cannot receive a return on generating plants economically-retired before the end of their depreciation lives to achieve least cost for customers.

Q. What applications of a positive net benefit calculation should the Commission consider in this remand proceeding and why?

A. The Commission should consider two applications of a positive net benefit calculation in this proceeding. First, it should consider reversing the disallowance of a portion of Trojan's un-depreciated balance. This decision rests entirely on the factually-derived negative outcome of the net benefits test. The Commission found a negative net benefit to closure of $27 million in UE 88 and ordered a corresponding disallowance to PGE's un-depreciated Trojan investment. A positive net benefit requires reversal of the $27 million disallowance.

Second, the Commission should consider whether, to encourage future analysis and implementation of early plant retirements that are in the public interest and under least cost planning principles, a "share-the-savings" mechanism could be appropriately applied to the calculated net benefit. The Commission approved a similar mechanism in connection with

[6] The after-tax number was $20.4 million.

another outcome of least cost planning: the acquisition of energy efficiency resources by utilities. In Order No. 91-98, the Commission adopted the SAVE program for PGE. This program, which was designed to "motivate PGE to aggressively pursue cost-effective energy efficiency measures," included a financial incentive for energy efficiency investment. As the Order explains:

> "The incentive component of the SAVE proposal allows PGE to earn revenues in addition to the allowed rate of return on capital investment over a period of 15 years. It provides for a sharing of the savings from non-use of electricity based on the value of verified energy efficiency savings that exceed benchmark levels." Order No. 91-98 at 3.

The SAVE incentive component is an instance of the Commission departing from the convention of basing rates on direct costs of electricity service. When necessary to promote important policies, such as the least cost planning framework, the Commission has discretion to depart from such conventions.

Q. What outcome or range of outcomes would result from the Commission revisiting its application of the net benefits test, restated for the revised calculations?

A. I addressed above the restoration of the $27 million disallowed from Trojan's un-depreciated balance.

With respect to a share-the-savings mechanism, any number of models exists. The SAVE mechanism ultimately resulted in an incentive payment of over 50 percent of the amount PGE invested in demand-side resources over the three-year period 1991 through 1994. The power cost adjustment (PCA) in place from the late 1970s to 1987 gave PGE 20 percent of the savings achieved from a quarterly-updated baseline net variable power cost. In UE 47/48, the Commission allocated to PGE 23 percent of the gain PGE created by selling a portion of our Boardman generating plant with an accompanying long-term power

purchase agreement.[7] For purposes of creating building blocks to use in this remand proceeding, we chose the 20 percent incentive of the PCA design.

The PGE Panel calculates that reversing the disallowance and adding a share-the-savings incentive increases revenue requirements across UE 88, UE 93 and UE 100 by $17 million.

D. Plant Classification

Q. Why are you suggesting that the Commission revisit its UE 88 decision regarding classification of Trojan's assets between plant-in-service and un-recovered plant accounts?

A. The Commission should revisit its decision regarding the classification of Trojan assets between plant-in-service and unrecovered plant because, as with its decision regarding an amortization period for un-depreciated Trojan investment, it relied on the assumption that it could allow PGE to recover its costs of capital regardless in which account PGE recorded the assets (Order No. 95-322 at 53). In other words, as the law stood when the Commission made this decision in UE 88, the decision made no practical difference.

In UE 88, the Commission acknowledged "that there is no prescribed method of accounting for nuclear plants that are in the process of being decommissioned." Based on evidence PGE presented in UE 88 and PGE Exhibit 6300, Quennoz-Peterson-Dahlgren, the Commission should find that certain Trojan assets remained in utility service to protect public safety and support decommissioning activity. The Commission may set a return of and on assets that remain in service. These assets are not subject to the Court of Appeals interpretation restricting the Commission's discretion to set rates by precluding a return on

[7] Order No. 87-1017 at 30.

assets that no longer provide service.

Although Order No. 95-322, at p. 54, cites FASB[8] Statement 90 as supporting the classification of assets to un-recovered plant, this provides limited guidance because one first must decide what "asset" is being abandoned. PGE was not abandoning any component of Trojan that remained necessary to protect public safety or enable government-required decommissioning work. These assets remained in service. An electric utility has many assets and components of assets not directly involved in generating or delivering electric energy. Fish ladders at hydro-electric generating plants and fences at substations are two examples. These facilities are used and useful to accomplish their utility service purposes and would remain so even if the hydro-electric plant or the substation were no longer in use to generate or distribute electricity.

Q. What outcome or range of outcomes could result from revisiting this decision?

A. Stephen Quennoz, Pete Peterson and Randy Dahlgren, PGE Exhibit 6300, support the analysis PGE presented in UE 88 that showed $80 million in un-depreciated Trojan investment remained in utility service following the closure decision. The PGE Panel calculates that, all else being equal, the proper classification increases revenue requirements in UE 88, UE 93 and UE 100. It also increases the un-depreciated balance remaining at the time of UM 989 even if the Commission chose a one-year amortization period for the un-depreciated investment that did not remain plant-in-service because these in service assets would have remained on the original 17-year depreciation life.

[8] FASB stands for Financial Accounting Standards Board.

E. Amortization Periods for Certain Customer Credits

Q. Are there amortization periods for balance sheet items other than Trojan that the Commission should consider?

A. Yes. PGE's 1995 balance sheet included a customer credit for the gain achieved in the 1985 sale of a portion of the Boardman plant. The Commission set a 27-year amortization period for that credit in UE 47/48. Order No. 87-1017 at 30. In UE 88, the Commission left the Boardman gain amortization period unchanged but, in UE 93, it accelerated these credits to use as offsets to several amounts customers owed PGE, including the AMAX termination payments, power costs deferred in several years, and the SAVE incentive PGE had earned. The Commission should, on remand, offset the remaining Boardman gain against an equal amount of un-depreciated Trojan investment before setting UE 88 rates. This would require that the Commission also establish amortization periods for AMAX, the deferred power costs, and SAVE in UE 93.

Q. Why should the Commission revisit this policy decision?

A. The reason why the Commission should revisit its policy decision to leave Boardman on a 27-year amortization schedule depends on the amortization period it decides is appropriate for PGE's un-depreciated Trojan investment in light of the Court of Appeals ruling.

If the Commission decides that a one-year amortization of Trojan is appropriate, accelerating Boardman's amortization would improve the matching of costs and benefits over time. Revisiting the amortization of Boardman improves the inter-generational equity associated with allowing PGE to recover its un-depreciated investment entirely from one year's customers, while customers would receive the benefits of such closure over at least 17 years.

If the Commission decides that a 17-year amortization of Trojan remained appropriate, accelerating amortization of the Boardman gain lessens the negative impact of the Trojan decision on PGE's financial integrity and ability to attract capital. Allowing PGE to offset the amounts owed customers for the Boardman gain with the amounts owed its investors for Trojan in effect allows PGE to recover some of the outstanding balance in one day. Although a one-day recovery is impracticable as a ratemaking matter, it is not impossible if accomplished as a netting of balance sheet entries. Because PGE would have experienced no loss of the time value of money associated with the amount of Boardman gain so applied, our write-off would have been less: $98 million rather than $149 million.

Q. Was the amortization period chosen for the Boardman gain the result of applying a ratemaking convention?

A. No. The amortization period for a credit to customers such as the Boardman gain is entirely within the Commission's discretion and should serve regulatory policy. No specific conventions exist. In the 1987 general rate case, UE 47/48, the Commission set the Boardman gain on a 27-year amortization schedule to match the period customers would have received such amounts had the sale of the plant been only a power sale instead of an asset sale accompanied by a power sale. The Commission found reason to depart from this rationale in November 1995, for UE 93. We suggest that, in light of the Court of Appeals interpretation, good reason now exists to shift that reconsideration of the Boardman amortization period from November to March 1995.

Q. What is the outcome of revisiting this decision?

A. Applying the remaining Boardman gain to reduce the un-depreciated Trojan investment available for ratemaking has various effects on the UE 88, UE 93 and UE 100 rate periods

and on the un-depreciated balance remaining at the time of UM 989. These effects depend on the combination of other building blocks assumed. Generally, applying the remaining Boardman gain to reduce the Trojan balance reduces the lost economic value resulting from collecting Trojan with no return over any assumed amortization period.

F. Recovery Timing of 1995 Net Variable Power Costs

Q. Why are you suggesting that the Commission revisit the timing of recovery of PGE's 1995 net variable power costs?

A. Revisiting this policy decision may be appropriate if the Commission decides that, on remand, the UE 88 amortization period for PGE's un-depreciated Trojan investment should be one year.

In UE 88, the Commission followed the standard ratemaking convention of setting rates to recover current costs, including net variable power costs. The Commission departs from this convention, however, when good reason exists to do so, such as a temporary and material rise in power costs. The first nine months of 2001 were a good example of this. In such cases, the Commission sets aside a portion of the current incurred costs for later recovery. The Commission spread the 2001 excess power costs over a period of almost 4 years, from 2002 through 2005. Among other purposes, this practice improves rate stability and predictability by smoothing unexpected lumpiness in costs.

If the Commission decided, on remand, that PGE should amortize its Trojan investment over one year, the total revenue requirement of current power costs and Trojan recovery would be temporarily high. In these circumstances, deferring a portion of current 1995

power costs for recovery in subsequent years would simultaneously improve the matching of the costs and benefits of the Trojan closure decision and increase rate stability.

Q. Was the inclusion of all of the 1995 forecasted net variable power costs in rates the result of applying a ratemaking convention?

A. Yes. As I explained above, the Commission typically considers, in setting rates for a given rate period, all of the costs the utility expects to incur to provide service during that period.

Q. Does good reason exist to change this convention here?

A. Yes, good reason exists if the Commission also decides that, in UE 88, it would have set the amortization period for PGE's un-depreciated Trojan balance at one year. The one-year increase and subsequent decrease in rates resulting from the Trojan amortization decision would have created rate instability, affecting customers' ability to make sound economic decisions regarding their use of electricity. In addition, the one-year period would not have matched the costs of achieving the net benefits of Trojan's closure with customers' receipt of those benefits. Deferring a portion of 1995 net variable power costs would help the Commission achieve this matching.

Q. What would be the outcome of revisiting this policy decision?

A. Revisiting this decision, in the context of a one-year amortization of un-depreciated Trojan investment, lowers UE 88 and four-months of UE 93 revenue requirements and increases subsequent revenue requirements. A significant amount of deferred power costs would have remained at the time of the UM 989 stipulation. The PGE Panel calculates the rate levels and balance sheet effects associated with this decision assuming that the Commission exactly offsets the un-depreciated Trojan investment with a power cost deferral. When

combined with other building blocks, the results of this assumption are provided by the PGE Panel. PGE Exhibit 6200, Section IX, Part B.

G. UE 88 Interest Costs

Q. Why do you suggest that the Commission, on remand, might include all of PGE's interest costs in rates, regardless of whether some of the debt related to un-depreciated Trojan investment?

A. We make this suggestion both on a legal basis, as explained in PGE's Pre-Trial Brief, Section V, Subsection H and because, from an economic perspective, it seems particularly unfair to claim that the prohibition of ORS 757.355 relates to the entire financing cost of the utility. Prohibiting an equity return requires that equity investors accept a zero return on their investment. However, forcing equity investors to pay the costs of debt financing imposes a further burden on equity investors and in fact requires that they accept a negative return to cover the contractual debt payments. In the case of Trojan, disallowing the debt and interest payments causes equity investors to lose approximately $41 million over the 5.5 years from April 1995 to September 2000 and $76 million over the full 17-year period in addition to the lost profit. PGE Exhibit 6201, Page 2.

Q. Would excluding both interest and profit related to un-depreciated Trojan investment be the result of applying a convention?

A. Yes. The Commission currently uses a specific rate times rate base – the term from the statute – to determine the basis for both a utility's interest costs and the cost of its common equity. This is the usual, although not the only, choice for common equity. But one can find the expected amounts of interest payments from a utility's accounts without regard to

rate base. Ultimately, the Commission is regulating to achieve an allowed return on equity and essentially a fixed component like O&M.

Q. Does good reason exist to change this convention here?

A. Yes. As with other factual decisions and policy choices I discuss above, applying this convention in UE 88 made no difference until the Court of Appeals interpretation. The Commission believed it could allow PGE to recover all of its capital costs – debt and equity – as well as its un-depreciated investment. This assumption is no longer valid. Applying this conventional way of calculating return will result in the penalty to equity investors explained above: not only will these equity investors lose their profit opportunity, but they will be required to cover the interest payments that must occur until the debt is retired.

We also note that some other jurisdictions (cited in PGE's Opening Brief), under similar but not identical circumstances, differentiated between the interest owed with respect to money borrowed for an uncompleted generating plant and the potential profit the utility would have made, denying the utility that potential profit but not requiring that the utility take a loss by absorbing the cost of the borrowed money.

H. Building Blocks Conclusion

Q. Are the above the only factual decisions and policy choices the Commission might have made differently in UE 88, had it known of the Court of Appeals interpretation?

A. No, they are not. It is impossible to know how knowledge of the Court of Appeals interpretation would have influenced the Commission's cumulative exercises of discretion in UE 88 as it strove to set rates that, in their end result, fell within the scope of its statutory

delegation, satisfied constitutional requirements and met the criteria I described in Section III. These are, however, the most obvious ones.

V. PGE's Position

Q. Please restate PGE's position from Section I of your testimony.

A. If the Commission had known that it could not establish rates including a return on un-depreciated balances of economically-retired generating assets even if it spread the recovery of such balances over time, then:

- In 1995, the Commission would have found fair and reasonable rates at least as high, if not higher, than the rates approved in Docket UE 88, Order No. 95-322; and
- In 2000, the Commission approved of the stipulations presented to it and the proposed $10 million rate reduction as fair and reasonable and a proper exercise of its discretion as a Commission in Docket UM 989, Order No. 00-601, because amounts owed PGE at that time would have exceeded the customer credits used as an offset. This would have provided economic as well as other benefits to customers from the resolution of the issues.

Q. What is the basis of your position?

A. We base our position on two sets of factual and policy decisions that we would have recommended in UE 88, either one of which we believe the Commission could and would have adopted. These sets of decisions meet the criteria I described above, although not to the same degree or in the same way.

Q. What is the first set of factual and policy decisions PGE would have requested that the Commission find in UE 88?

A. PGE would have requested, and believes the Commission reasonably would have found, that PGE should:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation and including the effects of the Court of Appeals ruling in the costs of closure and steam generator replacement in the costs of continued operation.
- Leave $80 million of the Trojan assets in the plant-in-service accounts.
- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not still plant-in-service and amortize the remainder over one year.
- Be allowed a required return on equity of 11.85 percent.
- Defer a portion of its 1995 and 1996 (four-months, to match the period of Trojan recovery) net variable power costs, for recovery over the subsequent ten years.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs and SAVE incentive over the same ten years.

The PGE Panel (PGE Exhibit 6200, Section IX.B) presents the effect of these revised factual and policy decisions on UE 88, UE 93, UE 100, and UM 989. The results, summarized in Table 1 below, show that no refund is due for any rate period because the UE 88, UE 93, and UE 100 rates are all the same or higher than the rates in effect during those periods:

Table 1
($000)

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirements	Revenue Requirement Difference
UE 88	621,028	627,510	6,482
UE 93	1,003,794	1,011,340	7,546
UE 100	3,674,898	3,679,829	4,931

The results also show that sufficient assets existed on PGE's balance sheet as of 2000 to support the offsetting of amounts owed PGE, $180 million, and amounts owed customers,

$161 million, per the stipulations the Commission exercised its discretion to adopt in UM 989.

Q. How does PGE's position comport with the criteria you presented in Section III?

A. Our position serves all of the criteria we presented above. I will address each separately.

Q. Please restate the first criterion and explain how PGE's position satisfies it.

A. Our first criterion uses the question:

> Does this decision encourage electric utilities to analyze and make resource decisions that will yield, "for society over the long run, the best combination of expected costs and variance of cost" to "assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"

PGE's position is at least neutral on this criterion. The use of a one-year amortization would have resulted in a $24 million write-off on PGE's balance sheet in 1995. This would not have been particularly encouraging, particularly when added to the $5 million additional write-off PGE took in connection with the UM 989 stipulations.[9] On the other hand, the higher required return on equity improves debt coverage and provides equity investors the opportunity for higher earnings. Also encouraging are the restoration of the previously-disallowed amount and the proper classification of assets necessary to protect public safety as utility plant in service.

Q. Please restate the second criterion and explain how PGE's position satisfies it.

A. Our second criterion uses the question:

> Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable

[9] These write-offs are additive to the $53 million pre-tax write-off ordered in UE 88.

burden of the costs or receives an inequitable share of the benefits?

PGE's position answers this question positively. No annual generation of customers over the period 1995 through 2000 would have borne an inequitable share of the costs of the least cost decision to close Trojan, nor received an inequitable share of the benefits.

Q. Please restate the third criterion and explain how PGE's position satisfies it.

A. Our third criterion asked the question:

> Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

PGE's position allows a positive answer to this question, for many of the same reasons as discussed under the first criterion.

Q. What is the second set of factual and policy decisions that PGE would have requested that the Commission find in UE 88?

A. PGE would have requested, and believes the Commission could reasonably have found that PGE should:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation and including the effects of the Court of Appeals interpretation in the costs of closure and steam generator replacement in the costs of continued operation.
- Receive 20 percent of the positive net benefit created through its economic retirement of Trojan, spread evenly over 17 years.
- Leave $80 million of the Trojan assets in plant-in-service accounts.

- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not still plant-in-service.
- Be allowed a required return on equity of 13.1 percent.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs and SAVE incentive over three years beginning with UE 88 rates.

The PGE Panel (PGE Exhibit 6200, Section IX.C)presents the effect of these revised factual and policy decisions on UE 88, UE 93, UE 100, and UM 989. The results, summarized in Table 2 below, show that no refund is due for any rate period because the UE 88, UE 93, and UE 100 rates are all the same or higher than the rates in effect during those periods:

Table 2
($000)

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirement	Revenue Requirement Difference
UE 88	621,028	621,090	63
UE 93	1,003,794	1,029,157	25,363
UE 100	3,674,898	3,707,946	33,048

Q. Please explain how well this scenario answers the question posed as criterion one.

A. Again, criterion one asks the question:

> Does this decision encourage electric utilities to analyze and make resource decisions that will yield, "for society over the long run, the best combination of expected costs and variance of cost" to "assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"

This scenario makes it harder to answer the question positively because, regardless of some of the positive regulatory policies assumed in this scenario, the result in 1995 would have been a $71 million write-off for PGE. The opportunity to earn a return on equity adjusted for the increased risk investors faced and the share-the-savings payment would have increased the return investors had an opportunity to earn, but such results would have come

only over time and subject to the outcome of other risks PGE faced then. The proper classification of Trojan assets in utility service to protect public safety or accomplish decommissioning also helps encourage least-cost planning decisions by subjecting to the incremental cost analysis only those costs truly avoidable. Protecting safety or meeting governmental requirements for decommissioning are not avoidable.

Q. Please explain how well this scenario answers the question posed as criterion two.

A. Again, this criterion asks:

> Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable burden of the costs or receives an inequitable share of the benefits of a given resource decision?

The continued use of a 17-year amortization schedule does help match the costs of closure well with the benefits customers would receive over the period of the net benefits analysis.

Q. Please explain how well this scenario answers the question posed as criterion three.

A. This criterion asks:

> Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

This scenario answers this question fairly well. The initial write-off would have weakened PGE's financial condition. Barring significantly unfavorable outcomes to the risks the Commission's ratemaking policies allocated to PGE (load, water, fuel), however, the opportunity to earn a higher return through the risk-adjusted required return on equity and

the temporary share-the-savings mechanism would have improved PGE's financial condition.

Q. Could the Commission, in deciding UE 88, have put the building blocks you discuss together in ways other than PGE's position and the 17-year scenario you discuss above?

A. Yes. For example, the Utility Reform Project (URP) has suggested that all revenue requirement associated with Trojan recovery of and return on should be applied against the un-depreciated balance of Trojan over the UE 88, UE 93 and UE 100 rate periods. One could construe this scenario as one in which the Commission sets an amortization period for the un-depreciated Trojan investment, such that the revenue requirement associated with return on that spread investment, is actually return of investment. This is not precise because using the "return on" revenue requirement in this way does not match any definite multiple-year amortization period.

Q. How would such a scenario measure against the criteria you presented?

A. It would measure up poorly. This scenario would have resulted in an immediate 1995 write-off of $149 million, harming PGE's financial health. Certainly, PGE and all other utilities would have felt no encouragement to engage in least cost planning analysis for existing plants, let alone implement a least-cost decision to retire one before the end of the depreciation life set by the Commission. The lack of recognition of increased risk associated with ORS 757.355 would discourage new investment, debt or equity. Although superficially this scenario would perform adequately at matching costs and benefits over time, in reality, significant costs would have been shifted to future customers, along with some risk that service would not be adequate.

Q. Would these ill-effects in fact have happened in 1995 and subsequent years?

A. No. We are now in 2005. The effects of any decision regarding what the Commission would have done in 1995 through 2000 will have no effect in those years. The effects will happen in 2005 and beyond. We will address this in more detail in Phase II of this docket, if necessary, but it is worth noting that the future effects of adopting scenarios that fail the criteria we present will affect future customers.

VI. Summary of Testimony

Q. Please identify the exhibits PGE is presenting.

A. PGE is presenting the following exhibits:

PGE Exhibit 6100 Ratemaking, Trojan History. Witness Randy Dahlgren reviews the basic methods and principles of ratemaking and describes the sequence of events in Oregon from Oregon's adoption of least cost planning through to the UM 989 settlement.

PGE Exhibit 6200, Quantitative Analysis (PGE Panel). Witnesses Patrick Hager, Jay Tinker, and Stephen Schue quantify the UE 88, UE 93, UE 100 and UM 989 balance sheet effects of the building blocks and assemble those into the one-year and 17-year scenarios I described in Section V.

PGE Exhibit 6300, Asset Classification. Witnesses Stephen Quennoz, Pete Peterson, and Randy Dahlgren explain why the work done to determine appropriate FERC accounting for Trojan assets upon its closure in 1993 should guide the Commission's classification of such assets for purposes of this UE 88 remand and why the earlier classification remains conservative based on knowledge subsequently gained.

PGE Exhibit 6400, Cost of Capital. Witness Patrick Hager explains why the Commission should have found that PGE's required return on equity in UE 88 was in the upper end of the range presented in that docket. He also details effects on PGE's ratios used by credit rating agencies to assess the security of amounts loaned PGE for un-depreciated Trojan investment amortization periods of one and seventeen years. Based on this analysis, he calculates a hypothetical capital structure that could help mitigate some of the negative effects of the amortization decision on PGE's ratios.

PGE Exhibit 6500, The Regulatory Compact. Witness Dr. Jeff Makholm, of the National Economic Research Associates, presents the principles of the regulatory compact as it has developed in the U.S., presents examples in other state jurisdictions of how Commissions have upheld the regulatory compact when dealing with retirement of nuclear plant which had a remaining depreciable basis, and explains how the Court of Appeals interpretation of ORS 757.355 jeopardizes the compact for both investors and customers in Oregon.

PGE Exhibit 6600, Impact on Rate of Return. Witness Dr. Colin Blaydon applies Discounted Cash Flow theory to concur that the required return on equity recommended by Patrick Hager is reasonable.

PGE Exhibit 6700, Risk Premium. Witness Dr. Alan Hess shows that equity investors require a risk premium on their required return under circumstances of asset impairment.

V. Qualifications

Q. Please state 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.

I. Introduction

Q. Please state your name and qualifications.

A. My name is Randy Dahlgren. I am Director of Regulatory Policy and Affairs at PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold. First, I describe the ratemaking process. While those involved in this docket are very familiar with this process, it is important that the record contain basic information on traditional ratemaking as well as some of the ratemaking tools that may be of assistance as the Commission develops a policy to deal with the unprecedented circumstances surrounding this case. Second, I discuss the series of events that led to the closure of the Trojan Plant and to the Commission's original decision in UE 88.

II. The Ratemaking Process

Q. How does the Commission generally set rates?

A. A utility's rates are typically set in the context of a Commission proceeding called a "general rate case," which is most often initiated with a filing by the utility (although the Commission can do so on its own motion). In the filing, the utility proposes new rates that produce a level of revenues (called the "revenue requirement") necessary to cover all costs of providing utility service including its cost of capital. The cost of capital includes a return for its owners (return on equity or ROE) that will result in rates that meet the statutory requirements as well as the Constitutional standards of a fair return found in the Hope and Bluefield decisions of the U.S. Supreme Court.

Q. Please describe the typical steps that occur in a general rate case.

A. A general rate case typically includes the following steps:

1. The utility files for a rate change by submitting to the Commission revised tariff sheets that incorporate new charges (rates). The utility's request is accompanied by supporting documents, including written testimony and exhibits that justify and explain the basis for the change.
2. The rate change becomes effective (generally after 30 days) unless the Commission suspends the filing for review and investigation.
3. If the rate change is suspended, an administrative law judge convenes a pre-hearing conference during which groups, including the OPUC Staff, that are interested in actively participating in the case (parties) are identified and a schedule is set.

4. Parties are given a period of time to submit written questions and data requests to the utility regarding the filing. The utility must respond to such questions within a set amount of time (typically ten business days).
5. Sometime during the process, one or more public hearings are held to hear directly from customers.
6. Parties submit written testimony responding to the utility's request.
7. The utility may submit written questions and data requests to the parties regarding their testimony.
8. The utility files written testimony rebutting the testimony of the parties. There may be additional rounds of rebuttal testimony, but the utility has the last opportunity as it has the "burden of proof."
9. All witnesses who submitted written testimony are made available for cross-examination in a series of hearings.
10. Parties submit final written arguments, or briefs, to the Commission, and the Commission may allow time for oral argument where the utility and parties present their arguments directly to the Commission.
11. The Commission issues its decision in the form of an order.
12. The utility files tariffs in compliance with the order.

Q. Please describe the statutory framework that the Commission uses to evaluate rate proposals.

A. The Legislature has given the Commission the mandate to "obtain for them [customers] adequate service at fair and reasonable rates." That delegation is captured in ORS 756.040(1), part of which I will quote here for convenience:

> "[T]he commission shall make use of the jurisdiction and power of the office to protect such customers, and the public generally, from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates. 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. How are a utility's revenue requirements determined?

A. Revenue requirements are typically based on the utility's cost of providing service over a 12-month operating period called a "test period" or "test year". The test period can actually be of a length other than 12-months, as it was in the original UE 88 docket, which used a 24-month period. The costs include operating and maintenance costs, depreciation and amortization, taxes, interest, and return on equity.

Q. Are costs always used to set utility rates?

A. For most utilities, costs serve as the bases for ratemaking. As James Bonbright states in his oft-quoted work <u>Principles of Public Utility Rates</u>:

> Nevertheless, one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is *necessary* cost or cost reasonably or prudently incurred. (Page 67)

I have included, as Exhibit 6102, the section contained on pages 67-68 of <u>Principles of Public Utility Rates</u> that this quote is from in order to provide a broader context of Dr. Bonbright's comments.

Q. Please discuss the issue of prudence.

A. In a general rate case, all of a utility's costs are subject to review regarding their prudence. I will not attempt to provide a complete legal description of prudence, but in layman's terms, prudence centers around questions such as:

- Were decisions to invest reasonable at the time they were made in light of the information reasonably available at the time?
- Were investments well managed given the conditions under which they were made?
- Are expenditures reasonable and necessary to provide safe and adequate service?

If the Commission finds imprudence, it will generally exclude from revenue requirements that amount of cost that exceeds a prudent level.

Q. Please describe further the use of a test period in determining a utility's revenue requirement.

A. As I stated, a 12-month operating period is typically used to determine the utility's costs to provide service. Depending on the jurisdiction and utility involved, it may be an historic 12-month period, an historic period adjusted for known or expected changes, or a forecast of a future period. The general objective is to establish a period that reflects the costs and customer usages that will occur when the new rates go into effect. PGE has used forecasted future test periods in its general rate cases since the 1970's. For example, PGE originally filed its UE 88 rate case on November 9, 1993 with an expectation that new rate levels would be approved by about January 1, 1995. Thus, the test period began January 1995. In the case, PGE proposed a 24-month test period to correspond with its proposed mechanism to "decouple" revenues and profits. The test period, then, ran from January 1995 through December 1996.

For the test period, we estimated PGE's Operations and Maintenance (O&M) costs, taxes, and the revenue requirements associated with the ownership of assets (depreciation expenses, interest costs, and ROE).

Q. How do you determine the revenue requirements associated with assets?

A. Recovery of investments in assets is based on a depreciation study approved by the Commission. The depreciation study identifies the expected useful life for each asset type, the estimated net salvage value (positive or negative) and the appropriate mechanism for recovering the plant balance over its useful life (e.g., straight-line, double declining balance, etc.). Depreciation studies are updated periodically, typically in conjunction with general rate cases, to reflect current experiences and expectations particularly with respect to the estimated useful life and net salvage value. For example, the depreciation study used in PGE's last general rate case (UE 115), established an expected useful life of electric meters of 10 years rather than 30 years as used in the previous study. This reflected an anticipated replacement of the current meter technology with new, electronic meters capable of remote reading.

Since the Commission approves the recovery of capital assets over a period of time through depreciation rates, the Commission recognizes that PGE must finance the initial acquisition of capital assets. This acquisition is financed with money invested by equity owners or borrowed from lenders. The financing costs for these funds are considered a component of PGE's cost of service just as O&M costs are considered a cost of service.

In a rate proceeding, the Commission establishes an appropriate capital structure that represents the sources of financing. Typically, such structures include both long-term debt and equity. Preferred stock may also be included in the capital structure. The Commission then establishes the appropriate costs associated with those sources of financing. The costs associated with long-term debt tend to be relatively easy to identify, as debt issues have required coupon/interest payments that must be made to the bondholder(s). In addition, the costs of long-term debt may incorporate issuance expenses, gains/losses on previously re-acquired debt issues, and other costs associated with long term debt. Like coupon/interest payments, these costs also are explicit and relatively easy to verify.

The cost of equity financing, by comparison, is more difficult to determine. There is no explicit cost that can be identified. Equity investors will only provide financing if they expect a return that is commensurate with the level of risk associated with investment. This appropriate amount of return will change over time based on economic conditions and risk levels. There are a number of methods used to estimate this cost, including the DCF and CAPM models described in more detail by Mr. Hager in PGE Exhibit 6400, Section II. Needless to say, these methods are complex and I do not discuss them except to point out that the Commission ultimately rules on an appropriate cost of equity financing as part of a ratemaking proceeding.

As an example, the Commission approved the capital structure and associated costs for PGE for the 1996 test year (OPUC Order 95-322, Appendix F, page 35) as shown in Table 1.

Table 1

Source of Financing	Amount ($000)	Share of Capital	Cost	Weighted Cost
LT Debt	$1,044,215	48.86%	7.82%	3.82%
Pref Stock	$ 99,703	4.67%	8.27%	0.39%
Comm Equity	$ 993,333	46.47%	11.60%	5.39%
Totals	$2,137,251	100.00%		9.60%

In UE 88, the Commission determined that PGE's overall cost of capital was 9.60%, reflecting the respective sources of financing and their associated costs. This rate was applied to PGE's rate base (the investment in assets less accumulated depreciation and accumulated deferred taxes) from UE 88 to derive the financing costs to be included in PGE's overall revenue requirement. In UE 88, the 1996 approved rate base totaled about $1.66 billion (including net Trojan investment). Multiplying $1.66 billion times 9.60% yields approximately $159 million of operating income that was included in PGE's revenue requirement to reflect the financing costs associated with undepreciated capital assets (*i.e.*, rate base).

Q. Debt appears to be a less expensive form of financing than equity. Why doesn't PGE just finance its capital assets with debt?

A. Increasing the debt load of PGE results in higher risk to lenders as our fixed interest/coupon payments increase. Thus, lenders would demand a higher return to lend money to PGE, increasing the cost of debt. Higher debt load also increases the risk to customers. There is less safety margin of equity to withstand financial shocks that otherwise would affect reliable service. By utilizing both debt and equity, PGE seeks to balance these factors and minimize the overall cost of capital.

Q. Has the Commission recognized these financing costs in establishing PGE's revenue requirement for rate setting purposes?

A. Yes. Commission decisions on rates have consistently recognized all of the costs described above as legitimate costs of service, not only for PGE, but for all of the utilities that come under rate regulation of the OPUC.

Q. Have you provided an example of why this is important?

A. Yes, Exhibit 6101 provides an example of a start-up utility and describes the importance of financing and the need for a utility to attract investment on reasonable terms.

Q. You have discussed the development of revenue requirements in a rate case. Are there any other steps involved in developing the rates that customers pay?

A. Yes, there are two additional steps that we refer to as rate spread and rate design.

Q. Please describe the rate spread process.

A. In rate spread, we allocate the total revenue requirements to classes or groups of customers. For example, residential customers are typically considered a customer class as are small commercial customers and large industrial customers. In Oregon, the Commission has determined that this allocation should be performed based on the utility's long-run marginal costs of providing service to each class. In other words, what is the cost of serving an additional kWh or getting service to an additional customer? Thus, while overall revenue requirements are based on our cost of providing service incorporating our existing system, rate spread is tied to the cost of providing additional service. The intent of this is to provide better "price signals" to customers as they consider using our service. We determine marginal costs of service for each customer class and then sum them to arrive at "total marginal costs." Since it would only be by happenstance that our revenue requirements would exactly equal our total marginal costs, we then adjust our marginal costs on an equal percentage basis to achieve this balance. We refer to this as an "equal percent of marginal costs". Once this is completed, we examine the results to ensure that they provide reasonable results.

Q. What was the result of this analysis in UE 88?

A. We found that a strict application of equal percent of marginal costs would yield rate increases for some customer classes (particularly residential) that were substantially above the average increase while others could potentially receive a rate decrease. We therefore recommended, and the Commission adopted, a methodology that moved towards equal percent of marginal costs but did not completely achieve that goal. The methodology, known as a “4-to-1” rate spread basically allocated to those classes that were currently below an equal percent of marginal costs four times the percentage increase allocated to the other classes. While this process is complicated and somewhat confusing to explain, one thing should be clear. There is no direct correlation between the prices paid by a particular customer class and any particular cost element used in determining the appropriate revenue requirements.

Q. Please describe the rate design process.

A. Rate design is the development of unit prices for each rate schedule. There are three basic types of charges for most of our customers: energy charges based on the amount of energy consumed, demand charges based on the maximum usage of a customer over a 30-minute period or on the customer’s maximum potential usage, and customer charges based on the customer’s connection to our system and on the related customer service functions provided. We use the results of our marginal cost study to guide our decisions as we develop unit prices that, when applied to our customers’ expected usage over the test period, yield the revenue requirement allocated to the particular class during the rate spread process. Again, by the time we get through rate design, there is no direct correlation between a particular charge and a particular cost element in revenue requirements.

Q. Are there a set of principles or objectives that you use in developing proposed rates?

A. Yes. We use a generally accepted set of rate objectives developed by Dr. Bonbright (see page 291 of Principles of Public Utility Rates) to guide our decision-making. The following is my paraphrase of those objectives for effective rates (Exhibit 6103 contains Dr. Bonbright's own words):

- Simple, understandable, and acceptable to the public
- Easily interpreted
- Meets revenue requirement
- Provides revenue stability
- Provides rate stability
- Apportions costs fairly among different consumers
- Avoids undue discrimination
- Discourages wasteful use/encourages justified use

To these, I would add one that is implied but not directly stated:

- Known by the customer and the utility at the time service is used/provided

Q. Why is this last objective important?

A. It is important because, although it serves as the basis for much of the process that I have described, it is not often explicitly stated. The rate case process is designed to develop a set of rates based on a set of costs. However, absent a tracking mechanism such as a power cost adjustment (PCA), or a deferral, once rates are established, they remain in effect until changed. We know that actual costs and customer loads will vary from those used to determine rates. We do not, however, go back and change rates that have been charged. Even when there is a tracking mechanism (e.g., power cost adjustment) rate changes are made prospectively – not retroactively. Customers and utilities need to know the rates that are in effect when they make decisions and not one year or two years or more down the road. This is completely analogous to prices we pay for products every day. I can only imagine the reaction if gas credit card statements contained different pricing than that on the pump when the purchases were made based on the oil company's later determination of its actual costs.

Q. But, if a cost changes doesn't that mean that customers are not receiving fair prices?

A. No, as I mentioned, costs change over time. In fact, most probably do. Some are higher and some are lower. If a utility believes that, in total, costs have increased, it can file a new general rate case or possibly a request for a deferral of specific costs. If other parties believe that, in total, costs have gone down, they can file a complaint case and request that the Commission open an investigation of the utility's rates, or they too can request a deferral. It should be clear, however, that once we step out of the ratemaking setting into the "real world" of actual costs and actual revenues, the tie between costs and tariff rates is broken. Let me give an example. Suppose that in a general rate case, the Commission determines that an appropriate estimate of annual maintenance costs of overhead lines is $25 million, that local property taxes are expected to be $30 million, and that meter reading expenses will be $4 million. And, as I've described, tariff rates are designed based on these costs. During the year after new rates become effective, however, weather conditions are relatively mild – there is not the normal level of wind damage – and maintenance of overhead lines is actually $22.5 million. On the other hand, voters pass some additional property tax levies, and actual property taxes are $32 million. Actual meter reading expenses are $4.5 million. In this case, if we assume that loads and all other costs are exactly as forecast, we can say that customers "paid" the correct amount for the total of overhead maintenance, property taxes, and meter readings, but the amount for each is unclear. Now, if we consider the actual situation where loads and essentially all cost elements are different from those used to set rates, the problem of identifying the tie between tariff rates and particular costs truly becomes indeterminate.

Q. You mentioned the ability to defer specific cost or revenue items. Doesn't this run counter to your argument that there is no tie between actual costs and tariff rates?

A. While the ability to defer costs or revenue items does appear contradictory, there are several additional factors that must be considered. First, the use of deferrals is relatively rare in the context of the number of cost elements involved. Second, the Commission addresses each request separately based on the unique regulatory and economic circumstances of the request. Finally, the Legislature has required that the Commission consider the overall earnings of the utility when addressing payments on collections under a deferral. This specifically addresses the issue that rates need to be appropriate on a total basis rather than just on an individual cost element basis.

Q. Does the Commission have any other tools besides general rate cases to use in its pursuit of safe and reliable service at fair and reasonable rates?

A. Yes, it does. Integrated resource planning (IRP) is an example of a tool used by the Commission to achieve its goals. The supply of electricity is not only usually the largest part of a utility's costs but also is the one most influenced by past and current decisions. While the costs of distribution are significant, the available choices are limited. The opposite is true of supply.

The Commission ordered that:

> "The goal of least-cost planning is most likely to be attained if all of the options available for providing service are considered and if all the costs are considered. Least-cost planning, as envisioned in this order, requires that broad examination of all the choices. Accordingly, the Commission concludes that the traditional responsibility of utilities for prudent management now explicitly includes the least-cost planning process and

> the timely acquisition of the least-cost resources." Order No. 89-507 at 2-3.

It stated its expectation that "[t]he results of the process is the selection of that mix of options which yields, for society over the long run, the best combination of expected cost and variance of cost." This tool then guides subsequent ratemaking decisions. "Although a decision made in the LCP process does not guarantee favorable ratemaking treatment, the process should provide some guidance to a utility." Id.

As I discussed above, another useful regulatory tool is deferred accounting. It allows the Commission to respond to unique circumstances such as a sudden and large increase or decrease in a particular cost element or to implement policies that mitigate or smooth rate changes by setting aside a cost or revenue change for future collection or refund.

The Commission has, in the past, used a number of tools in order to pursue policies that it determined were in the public interest and helped it meet its legislative mandate. For example, the Commission, in the early 1990s, decided that saving energy was most likely to result in future adequate service at fair and reasonable rates. The Commission believed that several significant ratemaking conventions, however, gave utilities every incentive **not** to help customers save energy. Among these were that the expenditures for energy efficiency, unlike those for a generating plant, could not enter rate base and thus offered no opportunity to increase net income and that customer savings between rate cases would reduce utility earnings. The Commission changed the convention of treating energy efficiency expenditures as a current cost and ordered utilities to accumulate these costs into rate base. It created mechanisms to hold utilities harmless from savings achieved between rate cases (decoupling). And, significantly, it offered utilities an opportunity to share in the "savings" created by acquiring saved kWh for less than it would cost to generate them (PGE's

"SAVE" mechanism). These ratemaking tools, then, enabled the Commission to pursue its goals.

Q. Please provide a brief discussion of the regulatory initiatives undertaken by the Commission prior to PGE's filing of UE 88.

A. Starting in 1989, the Commission began a number of initiatives designed to affect electric utilities' planning and need for new generating resources. First, as I mentioned earlier, in 1989 the Commission issued its least cost planning order (No. 89-507) whose goal was "the selection of that mix of options which yields, for society over the long run, the best combination of expected cost and variance of cost." In that year, the Commission also issued Order No. 89-1700 that authorized capitalization (or rate basing) of the costs of a utility's energy efficiency programs. This was designed to put demand side resources such as energy efficiency on a more equal footing with supply side resources (new generating plants).

The Commission also issued an order (No. 91-1383) that encouraged utilities to use competitive bidding for new resources, and in 1991 approved PGE's proposal for an incentive mechanism that allowed it a share of the savings associated with cost-effective demand-side resources that were installed under its energy efficiency programs (Order No. 91-98). The Commission, obviously, was highly involved and active in the resource planning and acquisition activities of utilities during this time frame.

These conventions or ratemaking tools were available to the Commission when it decided UE 88. With the different understanding of the law that we now have, the Commission may have used some of these tools, or revised its conventions in deciding UE 88.

III. History and Context

Q. Please briefly describe PGE's Trojan facility.

A. Trojan was a single-unit 1,200 MW pressurized water reactor nuclear generating facility. It began commercial operation in 1976, and was licensed to operate through 2011. PGE owned 67.5 percent of the plant. Trojan's use of steam generators in the pressurized water reactor system is important to this proceeding because it was the steam generators that played a major role in the circumstances that led to its early retirement. The Trojan plant contained four steam generators.

Q. Please briefly describe the tube degradation problem at Trojan.

A. The steam generator tubes contain most of the primary system radioactive water, and prevent the release of radioactive water to the secondary system. Each of Trojan's four steam generators contained several thousand tubes, which began to seriously degrade beginning in 1989. PGE used two techniques, plugging and sleeving, to address Trojan's tube degradation problem. Plugging removes a tube from operation by stopping the flow of primary system water through it, and sleeving involves permanently attaching a second tube within an existing degraded tube. By 1991 PGE had plugged or sleeved more than 25 percent of all Trojan steam generator tubes, which led to increased operation costs and decreased capacity of the plant.

Q. Given the increased O&M expenses and decreased capacity, what did PGE decide to do?

A. PGE considered three possible courses of action in its 1992 Integrated Resource Plan. These were 1) an immediate Trojan shut-down, 2) a phase-out, such that Trojan would close in mid-1996, and 3) continued operation of Trojan through 2011. The third option required the replacement of Trojan's steam generators.

Q. What were the conclusions of the 1992 IRP?

A. This Plan concluded that a Trojan phase-out was the least-cost option for customers over the 1992-2011 period.

Q. What new event occurred on November 9, 1992?

A. On November 9, 1992, a steam generator tube leak forced PGE to shut down the Trojan plant. This was shortly after submission of the 1992 IRP, but after the phase-out decision had been made.

Q. How did the Nuclear Regulatory Commission and the Union of Concerned Scientists respond to this event?

A. On December 1, 1992, the Nuclear Regulatory Commission (NRC) held a public meeting at Trojan to hear PGE's report on repair of the leak and determination that no similar welding flaws existed. This meeting also included some discussion of documents that the Union of Concerned Scientists (UCS) had recently released. The UCS documents indicated that there were differing professional opinions within the NRC regarding the safety analyses previously done for plants with steam generator micro-flaws, such as Trojan. Disagreements concerned both the ability to detect steam generator micro-flaws and the possibility that multiple tube leaks could lead to a serious accident. The UCS requested formal hearings on these matters prior to a Trojan restart.

Q. What did PGE then decide to do?

A. On December 4, 1992, PGE decided to delay restart to collect and evaluate data on the condition of the steam generator tubes. During this process, PGE learned that emergent cracks had developed since the 1991 inspections. The potential cost and complexity of testing and repair were very high.

Q. How did the Oregon Department of Energy respond to these Trojan-related events?

A. On December 9, 1992, the Oregon Department of Energy announced its decision to conduct public hearings on the safety of Trojan's steam generators in January 1993.

Q. Given these developments, did PGE decide to update its analysis?

A. Yes. Given these developments, PGE decided to update its 1992 IRP with a cost-benefit analysis of the decision whether to repair the steam generators and continue to rely on Trojan through mid-1996, or to close the plant immediately. Key parameters were Trojan's capacity factor, sleeving and outage costs, and short-term replacement power costs.

Q. What were the conclusions of this analysis?

A. This analysis showed immediate plant closure to be less expensive to customers, except under the combined assumptions of a very low mid-cycle outage probability and very high replacement power costs. Under mid-point replacement power cost assumptions, the net present value savings to customers of an immediate closure were between $78 million and $127 million, depending on the mid-cycle outage probability. PGE announced its decision to permanently close Trojan on January 4, 1993, and filed an Update to its 1992 IRP on February 2, 1993. The Update contained PGE's net benefit analysis supporting this decision.

Q. Did the Commission acknowledge PGE's IRP and Update?

A. Yes. The Commission acknowledged PGE's 1992 IRP and Update in Order No. 93-803 (LC-7).

Q. Did the Commission earlier request a legal opinion from the Oregon Department of Justice?

A. Yes, on March 19, 1992, the Commission requested an opinion from the Oregon Department of Justice concerning Trojan cost recovery if the plant were shut down with a substantial balance still to be recovered. The Department of Justice issued its response, Opinion Letter OP-6454, on June 8, 1992. Among other questions, the Commission asked whether it may allow rate recovery of the total plant costs, including decommissioning costs; recovery of the capital invested in the plant, and return on the unamortized or undepreciated investment during the recovery period. The Department of Justice answered in the affirmative, stating that the Commission has authority to allow recovery of capital and non-capital costs under both ORS 757.140 and the general ratemaking principle of "net benefits." The opinion letter also concluded that ORS 757.355 does not apply to a plant that has been in service.

Q. Please describe PGE's request for a declaratory ruling.

A. On February 9, 1993, PGE filed a request for a declaratory ruling, asking the Commission to state that it would apply its legal authority under ORS 757.140 and the "net benefit principle," and allow PGE to recover the capital and non-capital costs associated with the Trojan Plant through 2011, provided that PGE show, in a contested proceeding, that Trojan's retirement occurred "to assure an adequate and reliable supply of electricity at the least cost to the utility and its customers consistent with the long-run public interest." PGE based its understanding of the Commission's powers on Opinion Letter OP-6454. In Dockets DR-10 and UM 535 the Commission considered PGE's request, and responded in Order 93-1117, which it issued on August 9, 1993.

Q. Please describe the Commission's conclusions in Order 93-1117.

A. In Order No. 93-1117 the Commission concluded that a utility could demonstrate that a plant closure is in the public interest by means of showing a "net benefit" from that action. It also set out the conditions under which it would favor allowing PGE to recover some or all of its undepreciated Trojan investment and a return on that investment. First, PGE had to demonstrate that six assumed facts in the declaratory ruling request were actually true.

In addition to proving these six assumed facts, the Commission listed five additional conditions that PGE had to meet for the Commission to favorably consider allowing PGE to recover in rates some or all of the return of and return on its undepreciated investment in Trojan.

Q. Did PGE rely on the outcome of DR 10 in its subsequent general rate case, docketed as UE 88?

A. Yes, we did. We assumed that, if we met our burden of proof with respect to the required elements, the Commission would approve a revenue requirement for PGE that included our interest cost associated with Trojan and a profit opportunity on the remaining balance.

Q. How did PGE request Trojan cost recovery?

A. In Docket UE 88, PGE requested Trojan cost recovery based on a two-year 1995-96 test period. Specifically, PGE requested full recovery of the Trojan undepreciated balance based on a 17-year amortization of the Trojan balance ending in 2011 consistent with the then remaining depreciation period, the cost of debt – interest – associated with the remaining Trojan balance and an opportunity to earn a return on common equity on the outstanding Trojan balance over the test period.

Q. Please give an overview of how the Commission viewed PGE's request.

A. In considering PGE's request, the Commission relied on the framework of Order No. 93-1117. PGE and OPUC Staff agreed that PGE had proved all of the assumed facts, except for the third. Staff contended that PGE's $14.9 million in post-1991 capital costs incurred for analysis and plugging and sleeving of steam generator tubes should be disallowed, because these expenditures had never been in PGE's ratebase. Staff also recommended disallowance of the $2.2 million that PGE had spent for a spare coolant pump motor. PGE ordered the spare motor in 1991, but it had not yet been delivered when PGE closed the plant in early 1993. Staff argued that the purchase was not supported by adequate analysis. The Commission agreed with Staff on these two issues, leading to a disallowance of $17.1 million.

With respect to the second condition in DR 10 – diligent efforts to reduce other costs – the PGE and Staff cases disagreed. The Commission agreed with Staff that it was possible for PGE to be still more aggressive in its efforts to reduce costs. Accordingly, the Commission reduced PGE's revenue requirement by one percent, or $1.631 million and $1.687 million in 1995 and 1996 respectively.

The Commission considered PGE's 1992 IRP and Update sufficient to prove the sixth assumed fact under the Order No. 93-1117 framework. The 1992 IRP showed that a Trojan phase-out was the least-cost option. Then the Update showed that immediate shut-down was cheaper than phase-out.

The primary controversy in UE 88 arose in connection with the third condition of DR 10: PGE must show why it is reasonable to allow 100 percent recovery of Trojan-related costs in rates. The Commission determined to apply a net benefit test, based on the IRP result but updated for more current information, to answer this question and ensure "the ratepayers were held harmless for imprudent operation or management of Trojan, and to share costs between ratepayers and shareholders on that basis." Order No. 95-322 at 2. Numerous issues arose between the parties regarding the creation of the inputs to the net benefits test. Staff, in particular, recommended a number of changes to PGE's net benefit study.

Q. What were the results of the net benefits analysis, once it incorporated Staff's adjustments?

A. PGE's 1992 IRP net benefit analysis showed phase-out to be much cheaper for customers than continued operation through 2011. The analysis in PGE's Update then showed immediate shut-down to be much cheaper than phase-out. However, Staff's analysis in UE 88, which assumed lower O&M costs, a higher capacity factor, and a $183.1 million disallowance related to steam generator replacement, showed that shut-down had a net present value cost to customers that was $23.6 million greater than that of continued operation through 2011. This included a 45 MW increase in Trojan's capacity in 1996, concurrent with steam generator replacement, in the "continue operation through 2011" alternative. In other words, this analysis disallowed the cost of new steam generators required for continued operation through 2011 but included the increase in capacity that they enabled.

Q. How did the Commission rule on the net benefits analysis?

A. The Commission adopted Staff's $23.6 figure as the base cost to customers of PGE's decision to close Trojan. It then approved six of seven adjustments it considered. These were related to 1) timing of the 45 MW capacity upgrade, 2) capacity factor adjustment, 3) fixed O&M definition, 4) mismatch in nuclear fuel costs between Case 1b in PGE's 1992 IRP and Scenario 3 in the Update, 5) carrying charges related to capital replacements for alternative resources, and 6) capital costs for new gas-fired plants. There was also a final adjustment to account for interactions. The net result of these adjustments was to decrease the Staff's $23.6 million net benefit result by $3.2 million, or to $20.4 million.

Q. Please summarize the Commission's ruling on the net benefits test and other Trojan-related costs in docket UE 88.

A. The Commission accepted the adjusted Staff net benefit test result, which concluded that PGE's decision to close Trojan had a net present value customer cost that was $20.4 million higher than that associated with the alternative of continuing to run Trojan through 2011. The Commission then added this amount to the disallowances of $14.9 million and $2.2 million for post-1991 plugging and sleeving and the purchase of a spare reactor coolant pump motor respectively. This resulted in total Trojan-related disallowances of $37.5 million in the UE 88 docket. The Commission's order in this docket (No. 95-322) was issued on March 29, 1995, and implementing rates became effective for service on April 1, 1995.

Q. Please briefly summarize the major dockets that occurred subsequently: UE 93, UE 100 and UM 989.

A. In UE 93 PGE requested and the Commission approved increased rate levels that brought the recently completed Coyote Springs generating plant into rate base and increased variable power costs resulting from BPA's October 1995 rate increase. The order in this docket (No. 95-1216) also authorized the use of the gain resulting from PGE's sale of a portion of the Boardman Coal Plant to offset certain deferred amounts including: power costs and interest in UM 529, UM 594 and UM 692, the AMAX coal contract termination payment, and the incentive earned by PGE under the SAVE program (Schedule 101). Any remaining gain was applied to the Trojan balance. In total, about $117.2 million of Boardman gain was applied in this manner. The reduction in the Trojan balance was $20 million. The revised rates resulting from UE 93 became effective November 28, 1995.

Docket UE 100 was the culmination of a series of discussions held during 1996 between PGE, OPUC Staff, and other stakeholders regarding apparent significant power and fuel cost reductions that had occurred. These discussions resulted in a stipulation between PGE, OPUC Staff, the Citizens' Utility Board (CUB), and the Oregon Committee for Equitable Utility Rates (representing some of PGE's industrial customers) that provided for rate reductions for our customers. The OPUC opened UE 100 to consider the stipulation and adopted it by Order No. 96-306. The rate reduction went into effect on December 1, 1996.

Finally, in UM 989 the Commission adopted, by Order No. 00-601 dated September 29, 2000, a stipulation between PGE and OPUC Staff and one between PGE and CUB that were meant to resolve disputes concerning UE 88 rates by eliminating the remaining Trojan investment balances and offsetting them with various liabilities coupled with an approximate $6 million after-tax write-off by PGE. Also included was a rate reduction of $10.2 million (on an annual basis). The order was later affirmed by the Commission in Order No. 02-227.

IV. Qualifications

Q. Please state your qualifications.

A. I received a BS degree from Oregon State University in Electrical Engineering. In addition, I have taken courses from other universities in the areas of engineering economics, systems analysis, and business administration. I also attended the 1980 Public Utilities Executives' Course at the University of Idaho.

I joined PGE in 1973 shortly after graduation and subsequently have been involved in the areas of load research, load and revenue forecasting, price analyses and design, and class cost-of-service analyses. I was appointed Rate Engineer in January 1977 and have held various management positions in the regulatory area since 1978. I entered my present position as Director of Regulatory Policy and Affairs in 2001.

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List of Exhibits

PGE Exhibit	Description
6101	Example Start-Up Utility
6102	The Widespread Acceptance of a Cost-Price Standard
6103	Criteria of a Sound Rate Structure

Example Start-Up Utility

Imagine a new start-up utility (Metropolis Electric Co – MEC). Before MEC can serve any customers, it must build or purchase the infrastructure necessary to provide service. The infrastructure includes power plants to generate power, transmission lines to bring the power to its service territory, distribution infrastructure including poles and wires to bring the power to end use customers, transformers, electric meters, service trucks, billing and customer service systems, computers and desks, materials and supplies. MEC has 10,000 residential customers that it would like to serve. If it costs $5,000 per customer to build or purchase the infrastructure needed to begin service, MEC is going to need to raise $50,000,000 in capital.

Who will provide MEC with the necessary money? MEC could go to the debt markets. Lenders will require that MEC have an adequate financing profile and will be expected to make interest and principal payments against the loan (as well as a reserve margin – a "coverage ratio") before they lend any money to MEC, or to determine the interest rate on the debt.

MEC could also seek to find equity investors who will provide funding in exchange for a claim on the profits associated with the business as well as a residual claim on the assets of MEC after debt holders.

Any lenders or equity investors will take risks in providing MEC with money. First, the business may not generate the cash flow necessary to support interest/principal payments to the bondholders. This could occur if management wastes money on non-essential items, for example. Second, equity investors are not guaranteed any return on their investment. If MEC is faced with operating losses year after year, eventually MEC will go out of business, potentially without ever making a payment to its equity investors. As a result, any potential investor must weigh the alternatives of investing in other businesses. Generally speaking, investors would not invest in MEC unless they expected a return that is commensurate with potential returns of other investments of comparable risk.

After consideration of potential alternatives, MEC issues $25,000,000 in bonds that carry an 8% coupon rate and have a term of 30 years. These bonds are purchased by investors who supply MEC with the $25,000,000. The term of 30 years was selected since it matches the expected life of the assets that must be built/purchased. Potential equity investors review MEC's financial plan and forecasts for the coming years. After consideration of alternative investments of comparable risk that could provide an 11% return, they provide an infusion of equity of $25,000,000. Note that the $25,000,000 provided by the equity investors is not subject to any particular schedule of repayment. They are counting on the ability of MEC to generate income to justify their investment.

After obtaining the necessary funding, MEC builds/purchases the necessary infrastructure to begin serving customers. Simultaneously, MEC files its first rate case with the OPUC so that it can lawfully charge rates to its customers.

Both the equity investors and the holders of MEC's bonds are hopeful that the OPUC will allow a revenue requirement that reflects the costs of financing, as well as fuel, operating, and maintenance costs. Further, their investment is influenced by the ability of MEC's management team to manage the costs of the business. If, for example, the OPUC approved MEC's revenue requirement, but the cost of power increased, MEC's income would fall short of the $2.75 million ($25 million at 11%) that the equity investors had expected. But this start-up example does not end the story. MEC will require an annual infusion of new investment to support load growth and the replacement of worn out facilities. This will need to come from new debt or equity financing and/or from the retention and reinvestment of retained earnings in the business.

The point of this example is to illustrate the importance of attracting capital on an ongoing basis for a capital intensive business like an electric utility.

THE WIDESPREAD ACCEPTANCE OF A COST-PRICE STANDARD

No writer whose views on public utility rates command respect purports to find a single yardstick by sole reference to which rates that are reasonable or socially desirable can be distinguished from rates that are unreasonable or adverse to the public interest. A complex of tests of acceptability is required, just as would be the case with the tests of a good automobile, a good income-tax law, or a good poem. Nevertheless, one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—standard of cost of service, often qualified by the stipulation that the relevant cost is *necessary* cost of cost reasonably or prudently incurred. True, other factors of rate making are potent and are sometimes controlling--especially the so-called value-of-service factor in the determination of the individual rate schedules. But the cost standard has the widest range of application. Rates found to be far in excess of cost are at least highly vulnerable to a charge of "unreasonableness." Rates found well below cost are likely to be tolerated, if at all, only as a necessary and temporary evil.

A cost standard of rate making has been most generally accepted in the regulation of the levels of rates charged by private utility companies. But even more significant is the widespread adherence to cost, or to some approximation of cost, as a basis of rate making under public ownership. Thus the great Hydro-Electric Power Commission of Ontario purports to apply the principle of "service at cost" in its charges for wholesale power supplied to the various municipal distribution systems of the province. And thus most of the Federal power projects in the United States, including the Tennessee Valley authority, purport to sell electric power at rates designed to cover operating expenses plus a compensatory return on allocable capital investment—one form of cost-of-service standard. To be sure, critics of these projects have insisted that, under proper accounting, revenues would be shown to fall short of full-cost coverage. But the mere fact that these allegations are generally denied by the responsible managements of the Federal agencies implies that these managements themselves concede the validity of a cost principle of rate making.

Lest the foregoing remarks be taken to imply an adherence to a cost standard more rigid than the facts would justify, let me at once note exceptions. In the first place, the principle is followed far more closely as a measure of general rate levels than as a measure of individual rate schedules. In the second place, it is deliberately violated by those municipal power plants, said to be fairly numerous, that use the sale of electricity as a source of larger profits for the city treasury. And in the third place, it has been waived to a minor degree through the use of indirect subsidies in support of rural electrification in the United States; and waived to a major degree through the use of heavy subsidies for rural electrification in the province of Ontario. One may also note the huge deficits incurred in the operation of the Canadian National Railways, and the failure of most metropolitan transit systems, in recent years, to charge fares that cover operating expenses plus fixed charges.

Important, however, as are these and other deviations from a cost-price standard, they are generally treated as exceptions to the general rule of rate making. In Great Britain, even Labor Government that went much farther than did this country in the direction of socialization, including socialized medicine, did not see fit to abandon the general criterion of service at cost when it nationalized its public utilities. Instead, it instructed the various boards, such as the

British Electricity Authority, to undertake to realize total revenues sufficient to meet total outlays properly chargeable to revenue account, "taking one year with another."[1]

[1] The British statutes governing the rates to be charged by the nationalized public utilities and railroads do not expressly forbid sale of services at prices designed to yield revenues in excess of total cost. But they have been interpreted by British commentators as contemplating the provision of service "without making, so far as possible, either a deficit or a surplus." William A. Robson, ed., *Problems of Nationalized Industry* (New York, 1952). P. 335.

James C. Bonbright, *Principles of Public Utility Rates* (Columbia University Press 1961).
pgs. 67-68

CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    (a) in the control of the total amongst of service supplied by the company:
    (b) in the control of the relative uses of alternative types of service (on-peak versus of-peak electricity. Pullman travel versus coach travel, single-party telephone service versus service from a mulit-party line, etc.).

James C. Bonbright, *Principles of Public Utility Rates* (New York Columbia University Press 1961). pg. 291

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FAS 90 Impairment Test (Debt recovery allowed)
Reflects Plant in Service Reclass, post UE-88 writeoff

Trojan Unamortized Balance @ 4/1/1995 (Post UE-88 Writeoff)	$	340,162,435
FAS 71 Portion	$	17,582,008
Plant in Service Portion	$	80,000,000
Net FAS 90 Portion	$	242,580,427

Discount Rate (Incremental Cost of Debt)	8.0%
UE-88 Weighted Debt Cost	3.81%

17-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Plant in Srvc Depreciation	Total Amortization	FAS 90 Balance	FAS 90 Debt Recovery
1995	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 242,580,427	$ 9,230,185
1996	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 228,310,990	$ 8,687,233
1997	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 214,041,553	$ 8,144,281
1998	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 199,772,116	$ 7,601,329
1999	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 185,502,679	$ 7,058,377
2000	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 171,233,243	$ 6,515,425
2001	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 156,963,806	$ 5,972,473
2002	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 142,694,369	$ 5,429,521
2003	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 128,424,932	$ 4,886,569
2004	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 114,155,495	$ 4,343,617
2005	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 99,886,058	$ 3,800,665
2006	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 85,616,621	$ 3,257,712
2007	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 71,347,184	$ 2,714,760
2008	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 57,077,748	$ 2,171,808
2009	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 42,808,311	$ 1,628,856
2010	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 28,538,874	$ 1,085,904
2011	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 14,269,437	$ 542,952
Total	$ 242,580,427	$ 17,582,008	$ 80,000,000	$ 340,162,435		$ 83,071,667
PV	$ 130,160,639				PV - 17 years	$ 53,469,662

1-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Plant in Srvc Depreciation	Total Amortization	YE FAS 90 Balance	FAS 90 Debt Recovery
1995	$ 242,580,427	$ 17,582,008	$ 80,000,000	$ 340,162,435	$ 242,580,427	9,230,185
PV	$ 224,611,506				PV - 1 year	$ 8,546,468

17 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 242,580,427
PV of FAS 90 Cash Flows	$ 183,630,301
Pre-tax Write-Off	$ 58,950,126

Unamortized Balances after FAS 90 Write-Off:	
Plant in Service Portion	$ 80,000,000
FAS 90 @ 4/1/1995	$ 183,630,301
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 281,212,309

1 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 242,580,427
PV of FAS 90 Cash Flows	$ 233,157,974
Pre-tax Write-Off	$ 9,422,453

Unamortized Balances after FAS 90 Write-Off:	
Plant in Service Portion	$ 80,000,000
FAS 90 @ 4/1/1995	$ 233,157,974
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 330,739,982

Scenario Financial Ratios
Dollars in 000s

Scenario:	FFO	Interest Charges	Interest Incurred	FFO / Interest	Pre-Tax Income	Pre-Tax Interest Coverage
Base - 1995 Actual (Per 10K)	$ 248,053	$ 79,128	$ 80,749	4.16	$ 238,163	3.01
1 Year Amortization Scenarios:						
1 Year Amortization (no "return on")	$ 438,806	$ 79,128	$ 80,749	6.57	$ 200,951	2.54
1 Year Amortization (no "equity return")	$ 448,011	$ 79,128	$ 80,749	6.68	$ 212,316	2.68
1 Year Amortization (Plant in Service, no "return on")	$ 438,806	$ 79,128	$ 80,749	6.57	$ 210,009	2.65
1 Year Amortization (Plant in Service, no "equity return")	$ 451,662	$ 79,128	$ 80,749	6.73	$ 218,555	2.76
17 Year Amortization Scenarios:						
17 Year Amortization (no "return on")	$ 198,691	$ 79,128	$ 80,749	3.53	$ 75,351	0.95
17 Year Amortization (no "equity return")	$ 207,897	$ 79,128	$ 80,749	3.65	$ 146,454	1.85
17 Year Amortization (Plant in Service, no "return on")	$ 198,691	$ 79,128	$ 80,749	3.53	$ 115,558	1.46
17 Year Amortization (Plant in Service, no "equity return")	$ 211,547	$ 79,128	$ 80,749	3.69	$ 169,028	2.14

Including Effects of a 10% change in cap structure:	FFO	Interest Charges	Interest Incurred	FFO / Interest	Pre-Tax Income	Pre-Tax Interest Coverage
Base - 1995 Actual (Per 10K)	$ 259,837	$ 79,128	$ 80,749	4.30	$ 249,947	3.16
1 Year Amortization Scenarios:						
1 Year Amortization (no "return on")	$ 450,590	$ 79,128	$ 80,749	6.71	$ 212,735	2.69
1 Year Amortization (no "equity return")	$ 459,796	$ 79,128	$ 80,749	6.83	$ 224,100	2.83
1 Year Amortization (Plant in Service, no "return on")	$ 450,590	$ 79,128	$ 80,749	6.71	$ 221,793	2.80
1 Year Amortization (Plant in Service, no "equity return")	$ 463,446	$ 79,128	$ 80,749	6.88	$ 230,339	2.91
17 Year Amortization Scenarios:						
17 Year Amortization (no "return on")	$ 210,475	$ 79,128	$ 80,749	3.68	$ 87,135	1.10
17 Year Amortization (no "equity return")	$ 219,681	$ 79,128	$ 80,749	3.80	$ 158,239	2.00
17 Year Amortization (Plant in Service, no "return on")	$ 210,475	$ 79,128	$ 80,749	3.68	$ 127,342	1.61
17 Year Amortization (Plant in Service, no "equity return")	$ 223,331	$ 79,128	$ 80,749	3.84	$ 180,812	2.29

Scenario Financial Ratios
Dollars in 000s

Scenario:	Long-Term Debt	Equity	Total Cap	Debt / Total Cap	Average Debt	FFO / Debt	OPUC Equity	Tot Cap OPUC
Base - 1995 Actual (Per 10K)	$ 1,155,896	$ 901,694	$ 2,057,590	56.18%	$ 1,105,907	22.43%	$ 933,148	$ 1,863,704
1 Year Amortization Scenarios:								
1 Year Amortization (no "return on")	$ 1,155,896	$ 879,367	$ 2,035,262	56.79%	$ 1,105,907	39.68%	$ 910,821	$ 1,841,377
1 Year Amortization (no "equity return")	$ 1,155,896	$ 886,186	$ 2,042,081	56.60%	$ 1,105,907	40.51%	$ 917,640	$ 1,848,196
1 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 884,801	$ 2,040,697	56.64%	$ 1,105,907	39.68%	$ 916,255	$ 1,846,811
1 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 889,929	$ 2,045,825	56.50%	$ 1,105,907	40.84%	$ 921,383	$ 1,851,939
17 Year Amortization Scenarios:								
17 Year Amortization (no "return on")	$ 1,155,896	$ 804,007	$ 1,959,902	58.98%	$ 1,105,907	17.97%	$ 835,461	$ 1,766,017
17 Year Amortization (no "equity return")	$ 1,155,896	$ 846,669	$ 2,002,564	57.72%	$ 1,105,907	18.80%	$ 878,123	$ 1,808,679
17 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 828,131	$ 1,984,026	58.26%	$ 1,105,907	17.97%	$ 859,585	$ 1,790,141
17 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 860,213	$ 2,016,108	57.33%	$ 1,105,907	19.13%	$ 891,667	$ 1,822,223

Including Effects of a 10% change in cap structure:	Long-Term Debt	Equity	Total Cap	Debt / Total Cap	Average Debt	FFO / Debt	Equity	Tot Cap OPUC
Base - 1995 Actual (Per 10K)	$ 1,155,896	$ 908,764	$ 2,064,660	55.98%	$ 1,105,907	23.50%	$ 940,218	$ 1,870,774
1 Year Amortization Scenarios:								
1 Year Amortization (no "return on")	$ 1,155,896	$ 886,437	$ 2,042,333	56.60%	$ 1,105,907	40.74%	$ 917,891	$ 1,848,447
1 Year Amortization (no "equity return")	$ 1,155,896	$ 893,256	$ 2,049,152	56.41%	$ 1,105,907	41.58%	$ 924,710	$ 1,855,266
1 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 891,872	$ 2,047,767	56.45%	$ 1,105,907	40.74%	$ 923,326	$ 1,853,882
1 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 897,000	$ 2,052,895	56.31%	$ 1,105,907	41.91%	$ 928,454	$ 1,859,010
17 Year Amortization Scenarios:								
17 Year Amortization (no "return on")	$ 1,155,896	$ 811,077	$ 1,966,973	58.77%	$ 1,105,907	19.03%	$ 842,531	$ 1,773,087
17 Year Amortization (no "equity return")	$ 1,155,896	$ 853,739	$ 2,009,635	57.52%	$ 1,105,907	19.86%	$ 885,193	$ 1,815,749
17 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 835,201	$ 1,991,097	58.05%	$ 1,105,907	19.03%	$ 866,655	$ 1,797,211
17 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 867,283	$ 2,023,179	57.13%	$ 1,105,907	20.19%	$ 898,737	$ 1,829,293

Scenario Financial Ratios
Dollars in 000s

Scenario:	Equity Ratio - OPUC
Base - 1995 Actual (Per 10K)	50.1%
1 Year Amortization Scenarios:	
1 Year Amortization (no "return on")	49.5%
1 Year Amortization (no "equity return")	49.7%
1 Year Amortization (Plant in Service, no "return on")	49.6%
1 Year Amortization (Plant in Service, no "equity return")	49.8%
17 Year Amortization Scenarios:	
17 Year Amortization (no "return on")	47.3%
17 Year Amortization (no "equity return")	48.6%
17 Year Amortization (Plant in Service, no "return on")	48.0%
17 Year Amortization (Plant in Service, no "equity return")	48.9%

Including Effects of a 10% change in cap structure:	Equity Ratio - OPUC
Base - 1995 Actual (Per 10K)	50.3%
1 Year Amortization Scenarios:	
1 Year Amortization (no "return on")	49.7%
1 Year Amortization (no "equity return")	49.8%
1 Year Amortization (Plant in Service, no "return on")	49.8%
1 Year Amortization (Plant in Service, no "equity return")	49.9%
17 Year Amortization Scenarios:	
17 Year Amortization (no "return on")	47.5%
17 Year Amortization (no "equity return")	48.8%
17 Year Amortization (Plant in Service, no "return on")	48.2%
17 Year Amortization (Plant in Service, no "equity return")	49.1%

Scenario Financial Ratios
Dollars in 000s

Scenario:	Tot Cap Rating Ag	Equity Ratio - Rat	Dividends Paid	Net Cash Flow	Cap Ex	Net Cash Flow / Cap Ex	
Base - 1995 Actual (Per 10K)	$ 2,139,066	43.6%	(62,396)	$ 185,657	204,580	90.75%	
1 Year Amortization Scenarios:							
1 Year Amortization (no "return on")	$ 2,116,739	43.0%	(253,149)	$ 185,657	204,580	90.75%	
1 Year Amortization (no "equity return")	$ 2,123,558	43.2%	(262,354)	$ 185,657	204,580	90.75%	
1 Year Amortization (Plant in Service, no "return on")	$ 2,122,173	43.2%	(253,149)	$ 185,657	204,580	90.75%	
1 Year Amortization (Plant in Service, no "equity return")	$ 2,127,301	43.3%	(266,005)	$ 185,657	204,580	90.75%	
17 Year Amortization Scenarios:							
17 Year Amortization (no "return on")	$ 2,041,379	40.9%	(62,396)	$ 136,295	204,580	66.62%	Assumes ST Debt used
17 Year Amortization (no "equity return")	$ 2,084,041	42.1%	(62,396)	$ 145,501	204,580	71.12%	to make up cash flow
17 Year Amortization (Plant in Service, no "return on")	$ 2,065,503	41.6%	(62,396)	$ 136,295	204,580	66.62%	delta for 17-yr cases. Impact not
17 Year Amortization (Plant in Service, no "equity return")	$ 2,097,585	42.5%	(62,396)	$ 149,151	204,580	72.91%	calc'd on ratios

Including Effects of a 10% change in cap structure:	Tot Cap Rating Ag	Equity Ratio - Rat	Dividends Paid	Net Cash Flow	Cap Ex	Net Cash Flow / Cap Ex	
Base - 1995 Actual (Per 10K)	$ 2,146,136	43.8%	(62,396)	$ 197,441	204,580	96.51%	
1 Year Amortization Scenarios:							
1 Year Amortization (no "return on")	$ 2,123,809	43.2%	(253,149)	$ 197,441	204,580	96.51%	
1 Year Amortization (no "equity return")	$ 2,130,628	43.4%	(262,354)	$ 197,441	204,580	96.51%	
1 Year Amortization (Plant in Service, no "return on")	$ 2,129,244	43.4%	(253,149)	$ 197,441	204,580	96.51%	
1 Year Amortization (Plant in Service, no "equity return")	$ 2,134,372	43.5%	(266,005)	$ 197,441	204,580	96.51%	
17 Year Amortization Scenarios:							
17 Year Amortization (no "return on")	$ 2,048,449	41.1%	(62,396)	$ 148,079	204,580	72.38%	Assumes ST Debt used
17 Year Amortization (no "equity return")	$ 2,091,111	42.3%	(62,396)	$ 157,285	204,580	76.88%	to make up cash flow
17 Year Amortization (Plant in Service, no "return on")	$ 2,072,573	41.8%	(62,396)	$ 148,079	204,580	72.38%	delta for 17-yr cases. Impact not
17 Year Amortization (Plant in Service, no "equity return")	$ 2,104,655	42.7%	(62,396)	$ 160,935	204,580	78.67%	calc'd on ratios

Rev. Req. Model
Inputs in yellow
Figures Based on UE-88 (Order 95-322)

	At Current Rates	Additional Rev for 11.6% ROE	Proposed
1 Sales to Consumers	886,103	47,162	933,265
2 Sales for Resale	-		-
3 Other Revenues	10,795		10,795
4 Total Operating Revenues	896,898	47,162	944,060
5 Net Variable Power Costs	306,799		306,799
6 Fixed Power Costs	71,532		71,532
7 Other O&M	134,640	1,193	135,833
8 Total Operating & Maintenance	512,971	1,193	514,164
9 Depreciation/Amort	146,882		146,882
10 Taxes Other Than Income	48,579		48,579
11 Utility Income Tax	61,958	18,121	80,079
12 Total Operating Expenses & Taxes	770,390	19,314	789,704
13 **Utility Operating Income**	126,508	27,848	154,356
14 **Average Rate Base**			
15 Rate Base	1,585,834		1,585,834
16 Working Cash	36,726	879	37,605
17 **Average Rate Base**	1,622,560	879	1,623,439
18 **Rate of Return**	7.80%		9.51%
19 **Implied Return on Equity**	7.83%		11.60%
20 Effective Cost of Debt	7.710%	7.710%	7.710%
21 Effective Cost of Preferred	8.270%	8.270%	8.270%
22 Debt Share of Cap Structure	49.14%	49.14%	49.14%
23 Preferred Share of Cap Structure	5.42%	5.42%	5.42%
24 Weighted Cost of Debt	3.789%	3.789%	3.789%
25 Weighted Cost of Preferred	0.448%	0.448%	0.448%
26 Equity Share of Cap Structure	45.44%	45.44%	45.44%
27 State Tax Rate	6.672%	6.672%	6.672%
28 Federal Tax Rate	35.120%	35.120%	35.120%
29 Composite Tax Rate	39.449%	39.449%	39.449%
30 Bad Debt/FF/OPUC Rate	2.530%	2.530%	2.530%
31 Working Cash Factor	4.550%	4.550%	4.550%
32 Gross-Up Factor	1.651	1.651	1.651
33 ROE Target	11.60%	11.60%	11.600%
34 Grossed-Up COC	13.23%	13.23%	13.23%
Utility Income Taxes			
30 Book Revenues	896,898	47,162	944,060
31 Book Expenses	672,077	1,193	673,270
32 Interest Deduction	61,474	33	61,507
33 Deferred Ms	(28,219)	-	(28,219)
34 Book Taxable Income	191,566	45,936	237,502
35 State Taxes	12,781	3,065	15,846
36 State Tax Credits	(166)	-	(166)
37 Net State Taxes	12,615	3,065	15,680
38 Federal Taxable Income	178,951	42,871	221,822
39 Federal Taxes	62,848	15,056	77,904
40 ITC Amort	(1,985)	-	(1,985)
41 Deferred Taxes	(11,520)	-	(11,520)
42 Total Income Tax Expense	61,958	18,121	80,079

45,250.70	(1,911)
47,162.14	
49,073.67	1,912

Rate Base w/Trojan

RB	1,622,560
COE	19.16%
COD	7.710%
Cap Change	1%
Rev Req	1,857

Approx Rate Base w/o Trojan

RB	1,372,560	Trojan about $250 MM
COE	19.16%	
COD	7.710%	
Cap Change	1%	
Rev Req	1,571	

10% Change in Cap Structure (9 months):

Pre-Tax	11,784
After Tax	7,070

I. Introduction

Q. Please state your names and positions

A. My name is Jay Tinker. My position is Project Manager in the Rates and Regulatory Affairs Department. My qualifications are in Section X at the end of this testimony.

My name is Stephen Schue. My position is Senior Analyst in the Rates and Regulatory Affairs Department of PGE. My qualifications are in Section X at the end of this testimony.

My name is Patrick G. Hager. My position is Manager, Regulatory Affairs. My qualifications are in Section IV of PGE Exhibit 6400.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to identify and describe the financial impacts of the ratemaking tools (the "Building Blocks") available to the Commission in responding to the issue in this docket: what would the Commission have done in UE 88 if it had known of the Oregon Court of Appeals' interpretation. Ms. Lesh sets forth the Commission's use of, and regulatory foundation for, these Building Blocks. We focus on the financial impact of each Building Block and then analyze the financial impact of three approaches that combine various Building Blocks.

Q. What is the framework for your financial analysis?

A. We focus on four financial impacts. We review the Building Blocks' impact on PGE's revenue requirement over three rate periods; UE 88, UE 93, and UE 100 spanning the period April 1, 1995 (the effective date of UE 88) through September 30, 2000 (effective date of UM 989). We state how the revenue requirements during the various rate periods would differ using the Building Blocks as compared with the approved revenue requirements the Commission established in UE 88, UE 93, and UE 100. Throughout our testimony, we state the revenue requirement difference in *nominal* dollars, not net present value. In addition, we review the financial impact of the Building Blocks on PGE's balance sheet as of September 30, 2000.

Q. Why do you focus on these financial impacts?

A. This is a remand proceeding for the final orders in UE 88 and UM 989. The UE 88 revenue requirement, using the combination of Building Blocks we recommend, is important in determining whether a refund is due customers because of the UE 88 remand. If the revenue requirement under the Building Blocks the Commission would have selected in UE 88 is higher than the approved UE 88 revenue requirement, customers are due no refund. Similarly, PGE's balance sheet as of September 30, 2000, using the Building Blocks, is crucial to understanding whether the UM 989 settlement is reasonable.

Q. How do you state assets or liabilities in your testimony?

A. Unless otherwise noted, we use the *pre-tax balances*. That is, we do not include the effect of taxes unless we specifically note otherwise.

Q. Please explain how you use PGE's balance sheet as of September 30, 2000, to assess the UM 989 settlement and final order.

A. The UM 989 settlement and final order eliminated the remaining Trojan balance of $180 million in exchange for about $161 million in customer credits. The Commission found that the UM 989 settlement benefited customers because, among other things, it eliminated a customer debt of $180 million in exchange for only $161 million in customer credits. Under the alternative approaches we discuss that the Commission could have taken in UE 88, we review PGE's balance sheet to see whether customers still would owe PGE $180 million or more as of September 30, 2000. If so, the UM 989 settlement and final order continue to benefit customers because the settlement eliminates customer debts of over $180 million in exchange for customer credits of $161 million. In fact, remaining balances of less than $180 million, as long as above $161 million, would imply that customers still benefited from the UM 989 settlement.

Q. What assets do you review on PGE's balance sheet as of September 30, 2000?

A. We focus on customer liabilities to PGE that are available at the time. The nature of customer liabilities varies depending upon the combination of Building Blocks used. They include the Trojan unamortized balance, certain regulatory assets (AMAX, SAVE, and the Trojan replacement power deferrals), sharing of savings, the potential 1995 power cost deferral (see PGE Exhibit 6000, Section IV. F), and the difference in UE 88, UE 93, and UE 100 rate period revenue requirements using the Building Blocks.

Q. What do you mean by the difference in revenue requirements using the Building Blocks?

A. The revenue requirements in UE 88, UE 93, and UE 100 using the Building Blocks differ from the revenue requirements set in those cases. We take the net present value of that difference in revenue requirements and state it as a customer debt if the revenue requirement is higher using the Building Blocks or as a customer credit if the revenue requirement is less using the Building Blocks. This makes sense because we are trying to assess how PGE customers would have fared under the alternatives as compared with what actually occurred. We state this difference in revenue requirements in net present value terms as of September 30, 2000.

Q. What conclusions do you draw from the combination of Building Blocks Ms. Lesh recommends?

A. We conclude that no refund is due customers for the UE 88 rate period and that the UM 989 settlement still provides substantial benefit to customers and should be reaffirmed. Under both the alternatives Ms. Lesh recommends[1], the UE 88 revenue requirement would have been higher than the approved UE 88 revenue requirement and customers would have owed PGE more than $180 million as of September 30, 2000.

Q. Please outline your testimony.

A. We address the following topics:

- In Section II, we provide the ratemaking and financial impacts of different recovery periods for the Trojan investment, using a recovery period through 2011 (the "17-year recovery period"), and a one-year recovery period, as bookends.
- In Section III, we discuss re-evaluation of the cost of common equity and capital structure found in UE 88 based on ORS 757.355 as interpreted by the Court of Appeals, which concluded that rates may not include a return on economically retired plant.
- In Section IV, we restate the UE 88 net benefit test, given that the closure of Trojan scenario analyzed in that test should not include a return on the Trojan investment. We also set forth the impact on the UE 88 net benefits test if the Commission changed its decision in UE 88 and included recovery of steam generator replacement in the costs of continued Trojan operation.
- In Section V, we address the Building Blocks available based upon the restated UE 88 net benefits test, including the application of the Commission share-the-savings policy,

[1] See PGE Exhibit 6000. Ms. Lesh suggests two alternatives. However, a one-year amortization period along with other changes is considered preferable from a policy perspective than the second alternative, which uses a seventeen year amortization period.

developed to encourage utility energy efficiency investment, to the economic retirement of generating plant, thus yielding positive net benefits.

- In Section VI, we discuss the classification of the remaining Trojan plant to recognize as plant-in-service those portions of the plant still necessary for the protection of public safety.
- In Section VII, we describe the option of offsetting the unamortized Trojan balance with customer credits existing at the time of the UE 88 final order.
- In Section VIII, we discuss creating a new deferred account of certain 1995 net variable power costs for purposes of achieving intergenerational equity if the Commission selected a one-year recovery period for Trojan.
- In Section IX, we analyze the financial implications of three different alternative approaches, which combine in different ways the Building Blocks discussed above.

II. Amortization Period

Q. What recovery periods do you describe in this section?

A. A 17-year recovery period and a one-year recovery period. While there are other possible recovery periods, these two alternatives are instructive because they act as bookends.

A. 17-Year Recovery Period

Q. Please describe the impact of a 17-year recovery period with no return on equity and no recovery of PGE's debt costs on PGE's revenue requirement for UE 88, UE 93, and UE 100.

A. Under this scenario, the revenue requirement for each rate period would have been lower. Over the period from April 1, 1995 (the effective date of UE 88 rates) through September 30, 2000 (the effective date of the UM 989 settlement), the revenue requirement would have been lower in all periods. The total revenue requirement during this period, with these assumptions, would have been reduced by $186.5 million.

Q. Would this have had an immediate impact on PGE's balance sheet and earnings?

A. Yes. Financial Accounting Standard (FAS) 90 would require an adjustment to PGE's balance sheet to reflect recovery of the Trojan balance over time without any interest or equity return.

Q. Can you explain FAS 90 in more detail?

A. Financial Accounting Standard (FAS) 90 relates to accounting for abandoned plant costs and disallowances of plant costs. For plant balances that fall under FAS 90, an asset impairment test is required if it is likely that a regulatory commission will provide only a partial return on or no return on the remaining unamortized balance.

Q. Why is FAS 90 relevant to Trojan and these remand proceedings?

A. To the extent that the Commission considers alternatives to the UE 88 decision that allow no return on the Trojan balance, FAS 90 would require the application of an asset impairment test. The results of any impairment test should be included in the analysis of the effects of such an alternative Commission decision.

Q. Does the full unamortized balance of Trojan fall under FAS 90?

A. Not quite. Approximately $322 million of the $340 million unamortized balance for Trojan at April 1, 1995 was considered FAS 90 assets by PGE's auditors. The remaining $18 million of costs were considered assets under FAS 71 (regulatory assets). Prior to the write-off ordered in UE 88 pursuant to the net benefits test, the FAS 90 balance was approximately $345 million of a total unamortized balance of $367 million.

Q. What is a FAS 71 asset?

A. FAS 71 assets are assets created at the discretion of the Commission. Typically, these are the results of deferred O&M costs.

Q. Are FAS 71 and FAS 90 assets treated differently?

A. Yes. FAS 71 assets are not subject to impairment as long as full recovery of the asset is allowed by the Commission. FAS 90 assets, however, are subject to impairment if less than full return on the assets is authorized by the Commission.

Q. How does the FAS 90 impairment test work?

A. Basically, the FAS 90 impairment test is a comparison of the unamortized balance of the asset to the *present value* of the future cash flows authorized by the Commission to support that asset. Thus, if the Commission were to require no return on the unamortized balance, the size of the impairment would increase with the length of the Commission-required amortization period.

Q. What is the discount rate used in FAS 90 impairment testing?

A. The discount rate is the incremental borrowing rate of the company for debt of the magnitude and term of the Commission-approved unamortized balance and amortization period.

Q. How does the FAS 90 impairment test apply to a 17-year recovery period?

A. With a 17-year recovery period, the write-off pursuant to a FAS 90 impairment test would have been approximately $160 million on the pre-write off balance of $345 million and approximately $149 million on the $322 million of FAS 90 assets after the UE 88 write-off.

Q. For the 17-year recovery period, would FAS 90 require PGE to book the impact of the impairment immediately?

A. Yes. FAS 90 would require that the Trojan asset be written down at April 1, 1995 so that the asset's value was equal to the present value of the future cash flows authorized by the Commission that supported the asset.

Q. What happens in the other areas of the balance sheet?

A. The after-tax impact of the write-off would flow through net income and reduce retained earnings on the balance sheet.

Q. Does this assume PGE receives neither a return on equity nor recovery of its debt costs associated with the Trojan investment?

A. Yes. If the Commission were to allow recovery of PGE's debt cost, the impact of the impairment test would be reduced.

B. One-Year Recovery

Q. Please describe the revenue requirement impact of a one-year recovery period for the Trojan investment?

A. For the first twelve months after the effective date of UE 88 rates, PGE's revenue requirement would have been $262 million higher. Thereafter, the revenue requirement would have been lower by approximately $220 million over the period from April 1996 through September 30, 2000. Accordingly, the overall revenue requirement for the five and one-half year period from April 1995 through September 30, 2000, would have been $42 million higher.

Q. Please describe the impact on PGE's earnings and balance sheet of a one-year recovery period?

A. For the scenario in which Trojan is collected over one year, the FAS 90 impairment test would require a write-off of about $26 million for the pre-UE 88 write-off FAS 90 balance of $345 million and about $24 million for the $322 million post-UE 88 write-off FAS 90 balance.

III. Return on Equity, Debt Costs, and Capital Structure

Q. What is the distinction between return on equity and debt costs?

A. PGE's cost of capital has two components: debt and equity. The cost of debt represents interest payments that PGE must make or risk default. Return on equity is the profit opportunity investors require to make equity capital available. Failure to earn profit does not have the same legal consequences (default risk) as failure to pay debt.

Q. Why is the distinction important here?

A. As discussed in greater detail in the PGE Opening Brief, the Court of Appeals' interpretation held that ORS 757.355 prohibits a utility from earning a "profit" on retired plant. The Court of Appeals' interpretation does not address interest costs of outstanding debt securities.

Q. What is the financial impact of this distinction?

A. The impact varies depending upon the Building Blocks selected. Generally speaking, the distinction would increase the revenue requirement during the recovery period of Trojan. The magnitude depends upon the balance to which it applies and the amortization period. The particular approaches discussed in detail below and in PGE Exhibit 6000 all conservatively assume that the Oregon Court of Appeals' interpretation bars recovery of both interest costs and return on equity associated with the Trojan investment.

Q. What other Building Blocks are available to the Commission?

A. As Mr. Hager testifies (PGE Exhibit 6400, Section III.), the Court of Appeals' interpretation would have increased PGE's required return on equity in UE 88 because equity investors would view an investment in PGE as riskier. PGE's authorized return on equity would therefore need to be higher in order to attract capital and to provide equity holders with a return that is commensurate with the return on investment in other enterprises having corresponding risks.

Q. Under a 17-year recovery period, what would PGE's required return on equity have been?

A. According to Mr. Hager's testimony, PGE's required return on equity would have been 13.1%, or 150 basis points higher than authorized in UE 88.

Q. Would the authorized return on equity be the same for UE 93 and UE 100?

A. Yes. Neither UE 93 nor UE 100 changed the authorized return on equity set in UE 88.

Q. What effect would that cost of common equity have had on the revenue requirement over the five and one-half year period from April 1995 through September 30, 2000?

A. Over this five and one-half year period, the revenue requirement would have been $102 million higher than the approved revenue requirement.

Q. Under a one-year recovery period, what return on equity would have been required?

A. According to Mr. Hager's testimony, PGE's required return on equity would have been 11.85 percent or 25 basis points higher than the UE 88 level. This higher level of equity return applies to the UE 93 and UE 100 revenue requirement given that these rate orders did not alter PGE's authorized return on equity.

Q. What effect would that cost of common equity have had on the revenue requirement during the five and one-half year period from April 1995 through September 30, 2000?

A. PGE's revenue requirement would have been approximately $17 million higher.

Q. Do you believe the Commission would also change PGE's capital structure?

A. Yes. As Dr. Blaydon states (PGE Exhibit 6600, Section III.), a change in PGE's capital structure would have been appropriate if the Commission were to require a 17-year recovery period with no return on the Trojan investment.

Q. How did you calculate the adjustment to PGE’s capital structure?

A. First, for illustrative purposes we assumed a shift of 10% from debt to equity in the UE 88 capital structure. Second, we applied the difference between PGE’s pre-tax return on equity and cost of debt to PGE’s approved rate base with the Trojan investment removed.

Q. What is the annual impact of this change in PGE’s capital structure?

A. Based on UE 88, the annual impact would be an increase of $16 million in PGE’s revenue requirement.

Q. What would the financial impact be in UE 93 and UE 100?

A. The financial impact would be approximately the same. The only difference would be the result of changes in the approved rate base in UE 93 and UE 100.

Q. Do you include this capital structure adjustment in the scenarios proposed later in your testimony and in Ms. Lesh’s testimony?

A. No. Nevertheless, a capital structure adjustment is a well-recognized ratemaking tool that the Commission could use in dealing with the unprecedented circumstances presented in this docket.

IV. Net Benefit Test

Q. How did the Commission determine the amount of recoverable Trojan costs in UE 88?

A. The Commission applied a net benefits test to determine the allowable Trojan cost recovery. The net benefits test built on the work done in the 1992 IRP which found that an early phase-out (in 1996) of Trojan was the least cost option for PGE's customers. In a subsequent update to the 1992 IRP, PGE provided documentation that an immediate shutdown (in 1993) of Trojan was the least cost option for PGE's customers. The OPUC used the 1992 IRP and the subsequent update as the starting point of its analysis of net benefits in UE 88. Specifically, the Commission approved the use of Case 1-b from the 1992 IRP and Scenario 3 from the Update as the beginning point of analysis in UE 88.

Q. Can you describe the conceptual framework of the net benefits test?

A. Yes. The Commission conceptualized the net benefit test as follows (See Order No. 95-322, pg. 33):

(X + Y) > (X + Z), where:

X = Unamortized investment in Trojan

Y = Expected Allowable Long-Term Costs of continued Trojan Operation

Z = Replacement Resource Costs

Thus, a net benefit occurred if the Replacement Resource Costs (Z) were less than the Expected Allowable Long-Term Costs of Continued Trojan Operation (Y). The 1992 IRP Case 1b indicated a net customer benefit of a 1996 phase-out of Trojan of $110 million in then-present value terms. The Update to the 1992 IRP indicated a further net benefit to immediate shut-down in 1993 relative to a 1996 phase-out of $78 million (NPV). Thus, the starting point of the net benefit analysis in UE 88 was a net benefit of immediate Trojan closure of $188 million.

Q. What happened next?

A. During the UE 88 proceeding, the parties to the case debated the assumptions used by PGE to derive the $188 million net benefit of immediate shutdown over continued operation. Effectively, the parties debated the assumed Replacement Resource Costs (Z) and the assumed Expected Allowable Long-Term Costs of Continued Trojan Operation (Y). Ultimately, the Commission made determinations regarding these assumptions (see pages 34-52 of Order No. 95-322) to develop the final net benefit determination of negative $20.4 million (after-tax).

Q. What did this mean?

A. It meant that the Commission concluded that the immediate shut-down of Trojan was $20.4 million more costly than continued operation of the plant under the assumptions the Commission adopted. Thus, to provide a net customer benefit, the Commission required PGE to write-off $20.4 million (after-tax) of Trojan investment.

Q. Did PGE make the required write-off?

A. Yes. PGE wrote-down the unamortized balance of Trojan by $27 million to create the necessary after-tax write-off of $20.4 million.

Q. How does the Court of Appeals' interpretation affect the net benefits analysis?

A. The UE 88 net benefits test assumed that the value of the unamortized Trojan investment balance under the closure scenario and the continued operation scenario was the same (*i.e.*, the "X" term above). If rates could include a return on the Trojan investment under both scenarios, this assumption is reasonable. However, under the Court of Appeals' interpretation, the value of the unamortized investment (X) is no longer equal under the "closure" and "continued operation" scenarios.

Q. Please explain.

A. Under the assumptions the Commission used in UE 88, if PGE were to continue to operate Trojan, rates would include recovery of and a return on the unamortized investment in Trojan. However, if Trojan is closed, the Court of Appeals interpretation requires that rates only include recovery of the unamortized investment in the plant, with no return on. Thus, the treatment of the unamortized (or sunk) investment is not the same and therefore the unamortized investment (X) is not the same on both sides of the net benefits test. This is a direct result of the Court of Appeals' interpretation.

Q. How does the court's interpretation alter the net benefit test results?

A. The impact of customers not paying a return on is a function of both the amortization period and whether the prohibited return on is defined as the full return on or only the equity return component. The longer the amortization period with no "return on," the greater the "benefit" of the Trojan closure to customers. Also, as we have indicated before, we believe that return on should refer only to the equity return component and that debt costs should still be recoverable. However, we have done our analysis conservatively to assume the broader definition of "return on." The Commission should take into account the impact of the Court of Appeals' interpretation on the net benefits test by calculating the present value of the unamortized investment collected over any assumed amortization period. This will effectively calculate the benefit to customers under a closure scenario in which they would be responsible for recovery of the investment but not a return on the investment. Conceptually, the net benefits test can be written as:

Y > Z – X' where

X'= The difference between full recovery and the present value of providing recovery of, but no return on over a given amortization period.
Y = Expected Allowable Long-Term Costs of continued Trojan Operation
Z = Replacement Resource Costs

Q. Has PGE performed these calculations?

A. Yes, we have calculated the present value recovery of the investment with no return on under both a one-year amortization period and a 17-year recovery period. Under a one-year amortization period, by forgoing a "return on," the benefits to customers of the closure scenario increase by $23 million in present value terms. Under a 17-year recovery period, the benefits to customers of the closure scenario increase by $182 million.

Q. How much benefit do customers experience from the Trojan closure under either a 17-year recovery period or one-year recovery?

A. Under a 17-year recovery period, customers experience approximately $155 million in net benefit ($182 million - $27 million = $155 million). Under a one-year recovery period, customers experience approximately -$4 million in net benefit ($23 million - $27 million = -$4 million).

Q. Are there any other changes in the net benefits analysis that you propose?

A. Yes, the treatment of the costs to replace the steam generator.

Q. How did the Commission treat the replacement cost of steam generators in the UE 88 net benefits test?

A. The Commission excluded the cost of steam generators from the "continued Trojan operation" scenario. As Ms. Lesh's testimony explains (PGE Exhibit 6000, Section IV. C), PGE believes good grounds exist to revisit this decision.

Q. If the steam generator replacement is included in the "continued Trojan operation" scenario, please state how much customers benefited from the Trojan closure under both the 17-year recovery period and the one-year recovery period.

A. In the net benefit test performed in UE 88, the assumption that the steam generator replacement could not be included resulted in a $183 million reduction in the net benefits of the Trojan closure. Thus, if the Commission ruled that the steam generators were recoverable under the "continued operation of Trojan" scenario, the net benefit of Trojan closure would increase by $183 million. For a one-year amortization of Trojan, this would increase the net benefit of Trojan closure from negative $4 million to positive $179 million ($183 million - $4 million = $179 million). For the 17-year recovery period alternative, this would increase the net benefit of closing Trojan from positive $155 million to positive $338 million ($183 million + $155 million = $338 million).

V. Application of the Net Benefit Analysis

Q. How do the figures above alter the net benefits test and the amount of the Trojan balance?

A. First, we propose reversal of the disallowance of $27 million ruling in UE 88 that was based solely on the outcome of the net benefit test.

Under a one-year amortization period, the economic impact of the Court of Appeals' interpretation on the net benefits test is to reverse the net benefit from negative $27 million to negative $4 million. Thus, a reversal of $23 million of the $27 million write-off is required by application of the net benefits test used in UE 88.

Under a 17-year recovery period, the required revision to the net benefits test is to reverse the net benefit from negative $27 million to a positive net benefit of $155 million. Thus, we conclude that the net benefit of Trojan closure under scenarios that assume a 17-year collection period of Trojan requires the reversal of the entire $27 million disallowance in UE 88.

Q. The Commission also disallowed $27 million of Trojan investment in UE 88 for plugging and sleeving costs as well as a spare reactor coolant pump. Are these disallowances impacted by a reconsideration of the net benefit test for the impact of receiving no return on?

A. No. The disallowances were associated with decisions on PGE prudence made by the Commission that should not be impacted by this remand proceeding. By contrast, the write-off associated with the net benefit test was purely the result of the assumptions made in the application of the test.

Q. What impact would this restated net benefits test have on the unamortized Trojan balance?

A. Under the 17-year recovery period, the unamortized balance would be $367 million, as of the effective date of the UE 88 final order. Under the one-year recovery period, the unamortized Trojan balance would be $363 million.

Q. What effect would this change to the unamortized Trojan balance have had on the revenue requirements approved in UE 88, UE 93, and UE 100?

A. Under a one-year recovery period scenario, the impact would be a $23 million increase in the revenue requirement for the one-year recovery period. Under the 17-year recovery period scenario, the impact would be to increase the revenue requirement by $27 million collected over 17 years. Over the period April 1, 1995 through September 30, 2000, the 17-year scenario would have resulted in an additional recovery of $8.8 million.

Q. What is the positive benefit created by the decision to close Trojan if the "continued operation" scenario recognizes that PGE would need to replace its steam generators?

A. As explained above, under the 17-year recovery period, customers would experience a total net benefit of $338 million. Under a one-year recovery period, customers would receive $179 million in net benefit.

Q. How do you suggest the Commission could use these positive benefits created by PGE's decision to shutdown Trojan?

A. The Commission could decide that a sharing of the savings that resulted from the net benefit of closing Trojan is appropriate.

Q. How might the Commission have applied such a policy in this case?

A. In this case, the Commission could consider the net savings of Trojan closure relative to continued operation as a benefit to customers that should be shared with the utility.

Q. What effect would this decision have had on the revenue requirements in UE 88, UE 93, and UE 100?

A. Under a one-year amortization of Trojan, there are no net benefits to share unless the steam generators are considered recoverable under the "continued Trojan operation" scenario. As we addressed earlier, the net benefit of the early retirement of Trojan under a one-year recovery period is $179 million assuming the steam generators are recoverable. If the Commission were to apply a 20% sharing to the net benefit of $179 million, PGE would be allowed to collect approximately $36 million, which would increase the revenue requirement by that amount over the period collected. The 20% and other possible sharing percentages are discussed by Ms. Lesh in PGE Exhibit 6000, Section IV. C.

Under the 17-year recovery period approach, the Commission has multiple options. First, notwithstanding the treatment of steam generator replacement under continued operation, the Commission could allow the utility to share 20% of the savings that results from the net financial benefit of the Trojan closure of $155 million, or $31 million. If collected over 17 years, this would increase PGE’s revenue requirement by approximately $10 million over the period April 1, 1995 through September 30, 2000.

Alternatively, the Commission could rule that a sharing of the savings is appropriate that reflects the assumption that the replacement steam generators would be recoverable under the "continued Trojan operation" scenario. Under this case, PGE could be awarded 20% of $338 million, or $68 million. If collected over 17 years, this would increase PGE's revenue requirement by approximately $22 million over the period April 1, 1995 through September 30, 2000.

VI. Plant Classification

Q. For what plant is PGE suggesting the Commission reconsider the proper classification?

A. As shown in PGE Exhibit 6300, there is certain Trojan plant that continued to provide service to customers, even after Trojan was no longer producing electricity. This service includes protecting the public safety as well as providing for mandated decommissioning of the site.

Q. What useful life would the Commission use for these plant balances?

A. We assume that any plant classified as plant-in-service, rather than abandoned, should be recoverable, with "return on," over 17 years through 2011.

Q. What effect would this classification have on the revenue requirements in UE 88, UE 93, and UE 100?

A. Collecting approximately $80 million of plant classified as in service, with a return on over 17 years, increases PGE's revenue requirement by $70 million over the period April 1, 1995 through September 30, 2000.

Q. Would this classification affect the application of any of the other Building Blocks?

A. Yes. Many of the Building Blocks have interrelated effects. For the purposes of this discussion, we highlight only the incremental impacts of the item discussed. For example, if a portion of the Trojan investment were classified as plant-in-service <u>and</u> the Commission ruled on remand that a one-year amortization period applied along with a 25 basis point increase in ROE, the basis point increase would impact the return on the plant classified as plant-in-service. PGE Exhibit 6201 summarizes the incremental revenue requirement effects of the tools outlined in this testimony over the period April 1, 1995 through September 30, 2000.

VII. Balance Sheet Options

Q. Were there credits available at the time of the UE 88 final order that the Commission could have used to reduce the Trojan balance?

A. Yes.

Q. What were those credits?

A. There was only one credit available at the time, the Boardman gain. This was a customer credit to reflect the gain from the sale of a portion of the Boardman facility by PGE in 1985.

Q. What would the remaining Trojan investment for amortization have been if the Commission had used this balance as an offset against the Trojan balance?

A. The Commission could have used the balance of the Boardman credit of approximately $111 million at April 1, 1995 to reduce the unamortized balance of Trojan. As a result, the unamortized balance of Trojan would have decreased from $340 million, after the UE 88 disallowances, to approximately $229 million.

Q. Was the Boardman gain used later against other regulatory assets?

A. Yes. Just eight months later, in UE 93 (Order No. 95-1216), the Commission approved offsetting the Boardman gain against AMAX, SAVE, and Trojan Replacement power cost deferrals. In addition, a residual portion of the Boardman gain was used then to reduce the Trojan investment balance.

Q. If the Commission determines that it would have used the entire Boardman gain to reduce the Trojan balance in UE 88, what do you propose to do with those regulatory assets?

A. If the Boardman gain were used, in its entirety, to reduce the Trojan balance in UE 88, the AMAX, SAVE, and the Trojan Replacement power costs deferrals would have to be collected, with a return, over some period of time. The recovery period of these regulatory assets is largely a function of the Commission's goals of achieving rate stability and intergenerational equity across time. In PGE Exhibit 6000, Section V, Ms. Lesh suggests that the Commission ought to use a three year amortization period for these regulatory assets if it chooses to allow a 17-year amortization period for Trojan. However, if the Commission elects a one-year amortization period for Trojan, the Commission should elect a longer period of amortization of these regulatory assets (10 years) to improve rate stability and intergenerational equity.

VIII. Deferral of Power Costs

Q. Are there other Building Blocks available to the Commission under the one-year recovery period alternative?

A. As described in PGE Exhibit 6000, Section IV. F, the Commission could have authorized deferral of a portion of net variable power costs authorized over the one-year period beginning April 1, 1995.

Q. What were PGE's forecasted net variable power costs in UE 88?

A. The UE 88 rates were established to collect $309 million in annual net variable power costs.

Q. What would the impact have been on PGE's revenue requirement in UE 88?

A. To the extent UE 88 power costs were deferred, the revenue requirement in UE 88 would have been lower and collections from customers during the recovery period of the deferred balance would have been higher. The financial impact of a power cost deferral depends upon the amount deferred and the amortization period selected.

IX. Ratemaking Approaches Combining Various Building Blocks

Q. What Building Block combinations do you discuss in this section of your testimony?

A. We analyze in detail three approaches:

A. Approach I: One-Year Recovery and Restoration of UE 88 Disallowance

Q. What is the first approach?

A. The first approach is based on the following factual and policy decisions:

- Adoption of a one-year amortization period for the un-depreciated Trojan investment; and
- Calculation of the net benefits test based on a one-year amortization period with no return on, resulting in a partial restoration of the UE 88 write-off.

Q. Do you have an exhibit that shows the financial impact of this alternative throughout the five and one-half year period from UE 88 through UM 989?

A. Yes. The exhibit is PGE Exhibit 6202, Page 1.

Q. Can you please describe in detail that exhibit?

A. Yes. Column A of PGE Exhibit 6202, Page 1, shows the UE 88 revenue requirement compared with the UE 88 revenue requirement computed under this alternative for the UE 88 rate period from April 1, 1995, through November 27, 1995. Column B shows the UE 93 revenue requirement compared with the UE 93 revenue requirement computed under this alternative for the UE 93 rate period from November 28, 1995, through March 31, 1996. The purpose of this column is to show the financial impact for recovery of Trojan in one year. Column C shows the UE 93 revenue requirement compared with the UE 93 revenue requirement computed under this alternative for the remainder of the UE 93 rate period from April 1, 1996, through November 30, 1996. Column D shows the UE 100 revenue requirement compared with the UE 100 revenue requirement computed under this alternative for the UE 100 rate period from December 1, 1996 through September 30, 2000. Column E repeats Column A. Column F is the sum of Columns A and B. Column G is the sum of Columns A through D. Line 13 at the bottom of PGE Exhibit 6202, Page 1, shows what customers would have owed PGE at the time of the UM 989 settlement under this alternative.

Q. Do you have a table that summarizes this exhibit?

A. Yes. Table 1 below summarizes the key points of the PGE Exhibit 6202, Page 1.

Table 1
($000)

Period (All Begin 4/1/95)	Approved Revenue Requirement	Scenario Revenue Requirement	Revenue Requirement Difference
8 Months	56,502	239,153	182,651
1 Year	77,840	363,270	285,430
5.5 Years	298,187	363,270	65,083

It sets forth the revenue requirement differences during (1) the eight month period in which UE 88 rates were effective (Column A of PGE Exhibit 6202, Page 1), (2) the one-year period from April 1995 through March 1996 (Column F of PGE Exhibit 6202, Page 1), and (3) the five and a half year period from April 1995 through September 30, 2000 (Column G of PGE Exhibit 6202, Page 1).

Q. What does Table 1 show in terms of the revenue requirement under this alternative?

A. It shows that the revenue requirement under this alternative is substantially more than the approved revenue requirement. For example, during the one year following the effective date of UE 88 rates, the revenue requirement would have been in excess of $285 million more than the approved revenue requirement. Over the entire five and one-half year period, the revenue requirement under this approach would have been approximately $65 million more than the approved revenue requirement.

Q. What would PGE have been owed as of September 30, 2000?

A. PGE would have been owed approximately $183 million, as shown on line 14 of PGE Exhibit 6202, Page 1.

Q. Why is the amount customers would have owed PGE ($183 million) higher than the difference in the revenue requirements ($65 million)?

A. This reflects the fact that interest applies to the difference in revenue requirements. Under this scenario, most of the difference in revenue requirements occurs in 1995 and early 1996, when the revenue requirement would have been more than $285 million above the approved revenue requirement during the period. The interest rate used is PGE's authorized cost capital at that time.

Q. Under Approach 1, what conclusions do you draw regarding the final orders in UE 88 and UM 989?

A. This shows that there were no excess payments made by customers during the period April 1, 1995 to September 30, 2000. Under this scenario, revenue requirement would have been higher during the UE 88 rate period. In addition, the UM 989 settlement is still reasonable and a benefit to customers. In the UM 989 settlement, the Trojan balance of $180 million was offset against customer credits of $161 million. Under Approach 1, the Trojan balance is recovered in one year but customers owe PGE about $183 million at the time of the UM 989 settlement. Eliminating this $183 million customer liability by offsetting it against $161 million in customer credits still would provide customers with a substantial benefit.

B. Approach II: One-Year Recovery and Other Building Blocks

Q. What is the second combination of Building Blocks that you analyze in detail?

A. This second approach involves the following factual and policy decisions from UE 88:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation, and including the effects of the Court of Appeals' interpretation in the costs of closure and of steam generator replacement in the cost of continued operation.
- Leave $80 million of the Trojan assets in the plant in service accounts.
- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not plant in service and amortize the remaining balance over one year.
- Authorize a required return on equity of 11.85 percent.
- Defer a portion of PGE's 1995 and 1996 (four months, to match the period of Trojan recovery) net variable power costs, for recovery over the subsequent ten years;
- Recover the AMAX termination payment, pre-UE 88 deferred power costs, and SAVE incentive over the same ten years.

Q. To what rate base items does the increased ROE apply?

A. PGE's cost of capital would apply to PGE's rate base except for that portion of the Trojan investment that is classified as abandoned plant. It also would apply to interest on the regulatory assets under this approach.

Q. What is the balance of the power cost deferral?

A. The power cost deferral balance is $138 million.

Q. Why did you select this amount?

A. We selected this amount to improve the matching of costs and benefits of Trojan closure and achieve better rate stability, given recovery of the Trojan balance in one year.

Q. What is the financial impact of this approach?

A. Table 2 sets forth under this alternative the revenue requirement differences during (1) the eight month period in which UE 88 rate were effective (Column A of PGE Exhibit 6202, Page 2), (2) the one-year period from April 1995 through March 1996 (Column F of PGE Exhibit 6202, Page 2), and (3) the five and one-half year period from April 1995 through September 30, 2000 (Column G of PGE Exhibit 6202, Page 2).

Table 2
($000)

Period (All Begin 4/1/95)	Approved Revenue Requirement	Scenario Revenue Requirement	Revenue Requirement Difference
8 Months	260,125	266,606	6,482
1 Year	387,140	403,252	16,112
5.5 Years	607,487	626,446	18,959

Under this alternative, PGE's revenue requirement in UE 88 would have been slightly higher than the approved UE 88 revenue requirement ($6 million) and customers would have owed PGE about $198 million as of September 30, 2000.

Q. What is the basis for your conclusion?

A. PGE Exhibit 6202, Page 2, shows our analysis. The columns of PGE Exhibit 6202, Page 2, are the same as those set forth in PGE Exhibit 6202, Page 1.

Q. Please compare the approved UE 88, UE 93 and UE 100 revenue requirements with the corresponding revenue requirements under this approach.

A. As shown in Table 2, the revenue requirements under this approach are very similar to the approved revenue requirements. They differ by only $19 million over the five and one-half year period beginning April 1, 1995, which is less than one-half percent of the approved revenue requirement. This shows that the power cost deferral works to mitigate the impact of shortening the Trojan recovery period to one-year.

Q. What is the September 30, 2000 balance customers would have owed under this alternative?

A. It is $198 million, as shown on line 21 of PGE Exhibit 6202, Page 2.

Q. What is the basis for this balance?

A. The balance is composed of three pieces. First, the remaining balance of the Trojan plant classified as in service is about $42 million. Second, the balance for the regulatory assets (AMAX, SAVE, and Trojan replacement power cost deferrals) and the power cost deferral is about $127 million. Third, the revenue requirement under this scenario exceeds the approved revenue requirement by about $19 million plus applicable interest of $10 million. The total balance is the sum of these three component parts.

Q. Do you recommend this approach?

A. Yes, as discussed in PGE Exhibit 6000, Section V.

Q. What conclusions do you draw regarding the final orders in UE 88 and UM 989?

A. There were no excess payments from customers in UE 88 because the revenue requirement under this alternative is greater than the approved UE 88 revenue requirement. The UM 989 final order should be affirmed. Customers owe PGE $198 million under this alternative as of September 30, 2000, as compared with the Trojan balance of $180 million used in the UM 989 settlement. The UM 989 settlement looks more favorable to customers under this alternative because it uses $161 in customer credits to eliminate a $198 million customer liability.

C. Approach III: 17-Year Recovery Period and Other Building Blocks

Q. Please describe the third approach.

A. Under this third approach we use the following Building Blocks:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation, and including the effects of the Court of Appeals' interpretation in the costs of closure and of the steam generator replacement in the cost of continued operation.
- Receive 20 percent of the positive net benefit created through the economic retirement of Trojan, spread evenly over 17 years.
- Leave $80 million of the Trojan assets in plant in service accounts.
- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not plant in service.
- Authorize a required return on equity of 13.1 percent.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs, and SAVE incentive over the three subsequent years.

Q. Why did you shorten the recovery period for the regulatory assets in this alternative and eliminate the power cost deferral used in the second alternative?

A. In this approach, PGE is recovering the Trojan investment over 17 years instead of one; therefore no need exists to spread recovery of the regulatory assets over an extended period of time or for the power cost deferral. The 3-year amortization period is an appropriate choice for the Commission under this approach.

Q. How did PGE perform the net benefit test for this scenario?

A. In this scenario, we needed to take into account the portion of the Trojan asset that is plant in service and the reduction in the Trojan balance by the Boardman offset. Under this approach, the unamortized portion of the Trojan balance that remains classified as abandoned plant is $176 million after restoration of the disallowed amount in UE 88. The net benefit to customers of the Trojan shutdown is $256 million.

Q. How much of this benefit is shared with PGE?

A. PGE would receive 20% of the savings, which is consistent with Commission practice and precedent as discussed in PGE Exhibit 6000, Section IV. C.

Q. What is the impact on PGE's revenue requirement of this approach?

A. Table 3 sets forth under this alternative the revenue requirement differences during (1) the eight month period in which UE 88 rate were effective (Column A of PGE Exhibit 6202, Page 3), (2) the one-year period from April 1995 through March 1996 (Column F of PGE Exhibit 6202, Page 3), and (3) the five and one-half year period from April 1995 through September 30, 2000 (Column G of PGE Exhibit 6202, Page 3).

Table 3
($000)

Period (All Begin 4/1/95)	Approved Revenue Requirement	Scenario Revenue Requirement	Revenue Requirement Difference
8 Months	56.502	56,564	63
1 Year	77,840	85,017	7,177
5.5 Years	298,187	356,661	58,474

Under this approach, PGE's revenue requirement is quite close to the approved revenue requirements in UE 88, UE 93, and UE 100. For the five and a half year period, the revenue requirement would have been about $58 million more than the approved revenue requirement, or about one percent of the authorized revenue requirement.

Q. What is the impact on the UE 88 revenue requirement?

A. The UE 88 revenue requirement under this alternative is virtually identical to the approved UE 88 revenue requirement. This alternative would increase the revenue requirement by about $63,000.

Q. What is the balance owed to PGE as of September 30, 2000, under this alternative?

A. The balance is about $275 million, as shown on PGE Exhibit 6202, Page 3, line 20.

Q. How did you calculate the balance?

A. The balance has three parts. First, the unamortized Trojan plant is about $161 million (almost $43 million classified as plant-in-service and $118 million classified as abandoned). Second, there remains about $34 million of the share-the-savings to collect. Third, the revenue requirement under this scenario exceeds the approved revenue requirement by about $58 million plus interest of $22 million.

Q. Do you recommend this alternative?

A. Yes, as discussed in PGE Exhibit 6000. However, this approach is only recommended if the Commission approves a 17-year amortization period for Trojan.

Q. What conclusions do you draw regarding the final orders in UE 88 and UM 989 based upon this alternative?

A. During the UE 88 rate period customers did not make excess payments and the UM 989 settlement is reasonable and should be affirmed. Under this alternative, PGE's revenue requirement in UE 88 would have been higher and the customer liability eliminated by the UM 989 settlement ($275 million) would have been even greater than the $180 million in Trojan unamortized balance offset against $161 million in customer credits.

X. Qualifications

Q. Mr. Tinker, please describe your qualifications.

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. Mr. Schue, please summarize 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). Most recently, I worked on PGE's 2002 IRP and related Request for Proposals. In addition, I worked at the Oregon Public Utility Commission during 1986 and 1987, where my primary assignment was the economic analysis of conservation programs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
6201	Incremental Revenue Requirement Effects of Tools Available to the Commission
6202	Results of Revenue Requirement Approaches

PGE Exhibit 6201
Dollars in $000s

		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	Revenue Requirement Per Rate Orders							
1	Return On	22,146	10,164	18,881	87,319	22,146	32,310	138,510
2	Recovery Of	34,356	11,174	17,042	97,105	34,356	45,530	159,677
3								
4	**One-Year Amortization**							
5	Return	(22,146)	(10,164)	(18,881)	(87,319)	(22,146)	(32,310)	(138,510)
6	Return On Equity Only	(15,798)	(7,254)	(13,474)	(62,316)	(15,798)	(23,051)	(98,841)
7	ROE 25 Basis Points	1,753	1,075	2,097	12,056	1,753	2,827	16,980
8								
9	Trojan Balance Over One Year	223,940	116,222	-	-	223,940	340,162	340,162
10	Boardman Offset Over One Year	(73,174)	(37,977)	-	-	(73,174)	(111,151)	(111,151)
11	Reg. Assets -- Troj. Repl. Pow, AMAX, SAVE - 17 Years	7,232	3,753	7,323	42,109	7,232	10,985	60,417
12	Collect Def. Power Costs Over 17 Years	18,638	9,673	18,874	108,525	18,638	28,311	155,710
13	First Year Power Costs	40,370	20,951	-	-	40,370	61,321	61,321
14								
15	Net-Benefits							
16	Reversal of $23,108 of Disallowance	15,213	7,895	-	-	15,213	23,108	23,108
17	Reversal of $183,100 SG Disallowance	120,541	62,559	-	-	120,541	183,100	183,100
18	Share SG-Related "80/20"	24,108	12,512	-	-	24,108	36,620	36,620
19								
20	Plant in Service							
21	Collect Trojan Plant in Service Over 17 Years							
22	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
23	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
24	Collect Non-Plant in Service Trojan Over One Year	171,142	88,820	-	-	171,142	259,962	259,962

PGE Exhibit 6201
Dollars in $000s

		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	17-Year Amortization							
1	Return	(22,146)	(10,164)	(18,881)	(87,319)	(22,146)	(32,310)	(138,510)
2	Return on Equity only	(15,798)	(7,254)	(13,474)	(62,316)	(15,798)	(23,051)	(98,841)
3	ROE 150 Basis Points	10,517	6,447	12,580	72,336	10,517	16,965	101,881
4	Capital Structure - Shift 10% Debt to Equity	10,344	5,368	10,475	60,230	10,344	15,712	86,417
5	Recovery of Debt Costs	5,854	2,958	5,598	27,489	5,854	8,812	41,898
6								
7	Trojan Balance Over 17 Years	13,370	6,939	13,539	77,848	13,370	20,308	111,695
8								
9	Plant in Service							
10	Collect Trojan Plant in Service Over 17 Years							
11	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
12	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
13	Collect Non-Plant in Service Trojan Over One Year	10,217	5,303	10,347	59,494	10,217	15,520	85,361
14								
15	Net-Benefits							
16	Reversal of $26,828 Disallowance	1,054	547	1,068	6,140	1,054	1,602	8,809
17	Share "Net""No Return On" Savings "80/20"	1,220	633	1,235	7,103	1,220	1,853	10,192
18	Share "Net" No Return on Savings After Bdman and In Svc "80/20"	512	266	518	2,980	512	777	4,276
19	Share "Net" "No Ret. On Equity" Savings "80/20"	827	429	837	4,814	827	1,256	6,907
20	Reversal of $183,100 SG Disallowance	1,439	747	1,458	8,381	1,439	2,186	12,024

PGE Exhibit 6202
Dollars in $000s

		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	One Year Collection of Trojan with Other Changes:							
	Scenario Revenue Requirement:							
1	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
2	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
3	25 Basis Pts. ROE Increase	1,825	1,110	2,166	12,456	1,825	2,935	17,557
4	Collection of Trojan and 26.8, Net of Class. In-Service and Board., Over One Year	115,629	60,010	-	-	115,629	175,639	175,639
5	First Year Power Costs	112,918	58,603	-	-	112,918	171,521	171,521
6	Reg. Assets Collection Over 10 Years	9,424	4,891	9,544	54,877	9,424	14,316	78,736
7	Deferred First-Year Power Cost Collection Over 10 Years	13,489	7,000	13,659	78,541	13,489	20,489	112,689
8	Total Scenario Revenue Requirement Changes	266,606	136,646	33,839	189,355	266,606	403,252	626,446
9								
10	**Revenue Requirement per Rate Cases:**							
11	First Year Power Costs	203,623	105,678	-	-	203,623	309,300	309,300
12	Trojan Revenue Requirement	56,502	21,338	35,923	184,424	56,502	77,840	298,187
13	Trojan and Power Cost Revenue Requirement	260,124	127,016	35,923	184,424	260,124	387,140	607,487
14								
15	Revenue Requirement Difference	6,482	9,630	(2,084)	4,931	6,482	16,112	18,959
16								
17								

18	Derivation of Balance Owed PGE @ 9/30/2000:	
19	80,200	Trojan Plant in Service Balance @ 04/01/95
20	(37,647)	Recovery of Plant in Service Balance Over Period 04/01/95 - 09/30/00
21	18,959	Revenue Requirement Differential (Scenario Revenue Requirement Less Trojan & Pwr Cost Rev. Req.)
22	9,712	Interest on Revenue Requirement Differential
23	126,998	Remaining Balance for Reg Assets and Deferred Power Costs @ 09/30/00
24	198,222	Balance Owed PGE @ 9/30/2000

PGE Exhibit 6202
Dollars in $000s

		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	17 Year Collection of Trojan with Other Changes:							
	Scenario Revenue Requirement:							
1	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
2	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
3	150 Basis Pts. ROE Increase	10,948	6,661	12,998	74,736	10,948	17,609	105,343
4	20% STS (Based on SG, Return Foregone Net of Bdmn, Net of 26.8)	2,010	1,043	2,035	11,702	2,010	3,053	16,790
5	Collection of Trojan and 26.8, Net of Class. In-Service and Board., Over 17 Years	6,903	3,583	6,991	40,196	6,903	10,486	57,673
6	Reg. Assets (AMAX, SAVE, Troj Repl NVPC Over 3 Years)	23,382	12,135	23,678	47,357	23,382	35,518	106,553
7	Total Scenario Revenue Requirement Changes	56,564	28,453	54,171	217,473	56,564	85,017	356,661
8	**Revenue Requirement per Rate Cases:**							
9	Trojan Revenue Requirement	56,502	21,338	35,923	184,424	56,502	77,840	298,187
10	Revenue Requirement Difference	63	7,115	18,249	33,048	63	7,177	58,474
11								

12	Derivation of Balance Owed PGE @ 9/30/2000:	
13	80,200	Trojan Plant in Service Balance @ 4/1/1995
14	(37,647)	Recovery of Plant in Service Balance Over Period 04/01/95 - 09/30/00
15	58,474	Revenue Requirement Differential (Scenario Revenue Requirement Less Trojan Revenue Requirement)
16	21,578	
17	175,639	04/01/95 Balance, Net of Boardman Gain and Plant in Service, with Restoration
18	(57,673)	Payments on Net Trojan Balance Over Period 04/01/95 - 09/30/00
19	34,343	Remaining STS Balance 09/30/00
20	274,915	Balance Owed PGE @ 9/30/2000

PGE Exhibit 6202
Dollars in $000s

		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	One-Year Trojan Collection and Restoration							
	Scenario Revenue Requirement:							
1	One-Year Amortization	223,940	116,222	-	-	223,940	340,162	340,162
2	Restoration of UE 88 Write-Off	15,213	7,895	-	-	15,213	23,108	23,108
3	Total Scenario Revenue Requirement Collections	239,153	124,117	-	-	239,153	363,270	363,270
4								
5	**Revenue Requirement per Rate Cases:**							
6	Trojan Revenue Requirement	56,502	21,338	35,923	184,424	56,502	77,840	298,187
7	Revenue Requirement Difference	182,651	102,779	(35,923)	(184,424)	182,651	285,430	65,083
8								
9								

10	Derivation of Balance Owed PGE @ 9/30/2000:	
11		
12	65,083	Revenue Requirement Differential (Scenario Revenue Requirement Less Trojan Revenue Requirement)
13	118,409	Interest on Revenue Requirement Differential
14	183,492	Balance Owed PGE @ 9/30/2000

Support for Lesh Testimony

Combination 1

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirement	Difference
UE 88	621,028	627,510	6,482
UE 93	1,003,794	1,011,340	7,546
UE 100	3,674,898	3,679,829	4,931
Total	5,299,719	5,318,678	18,959

Combination 2

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirement	Difference
UE 88	621,028	621,090	63
UE 93	1,003,794	1,029,157	25,363
UE 100	3,674,898	3,707,946	33,048
Total	5,299,719	5,358,194	58,474

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Apr-95	2,738	1,984	754
May-95	2,724	1,974	750
Jun-95	2,710	1,964	746
Jul-95	2,697	1,954	743
Aug-95	2,683	1,944	739
Sep-95	2,669	1,934	735
Oct-95	2,656	1,924	731
Nov-95	2,642	1,914	728
Dec-95	2,628	1,905	724
Jan-96	2,637	1,913	724
Feb-96	2,623	1,903	721
Mar-96	2,610	1,893	717
Apr-96	2,596	1,883	713
May-96	2,582	1,873	709
Jun-96	2,568	1,863	705
Jul-96	2,555	1,853	702
Aug-96	2,541	1,843	698
Sep-96	2,527	1,833	694
Oct-96	2,513	1,823	690
Nov-96	2,500	1,813	686
Dec-96	2,486	1,803	683
Jan-97	2,472	1,793	679
Feb-97	2,458	1,783	675
Mar-97	2,444	1,773	671
Apr-97	2,431	1,763	668
May-97	2,417	1,753	664
Jun-97	2,403	1,743	660
Jul-97	2,389	1,733	656
Aug-97	2,376	1,723	652
Sep-97	2,362	1,713	649
Oct-97	2,348	1,703	645
Nov-97	2,334	1,693	641
Dec-97	2,320	1,683	637
Jan-98	2,307	1,673	634
Feb-98	2,293	1,663	630
Mar-98	2,279	1,653	626
Apr-98	2,265	1,643	622
May-98	2,252	1,633	618
Jun-98	2,238	1,623	615
Jul-98	2,224	1,613	611
Aug-98	2,210	1,603	607
Sep-98	2,197	1,593	603
Oct-98	2,183	1,583	599
Nov-98	2,169	1,573	596
Dec-98	2,155	1,563	592
Jan-99	2,141	1,553	588
Feb-99	2,128	1,543	584
Mar-99	2,114	1,533	581
Apr-99	2,100	1,523	577
May-99	2,086	1,513	573
Jun-99	2,073	1,503	569
Jul-99	2,059	1,493	565
Aug-99	2,045	1,483	562

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Sep-99	2,031	1,473	558
Oct-99	2,018	1,463	554
Nov-99	2,004	1,453	550
Dec-99	1,990	1,443	547
Jan-00	1,976	1,433	543
Feb-00	1,962	1,423	539
Mar-00	1,949	1,413	535
Apr-00	1,935	1,403	531
May-00	1,921	1,393	528
Jun-00	1,907	1,384	524
Jul-00	1,894	1,374	520
Aug-00	1,880	1,364	516
Sep-00	1,866	1,354	512
Oct-00	1,852	1,344	509
Nov-00	1,838	1,334	505
Dec-00	1,825	1,324	501
Jan-01	1,811	1,314	497
Feb-01	1,797	1,304	494
Mar-01	1,783	1,294	490
Apr-01	1,770	1,284	486
May-01	1,756	1,274	482
Jun-01	1,742	1,264	478
Jul-01	1,728	1,254	475
Aug-01	1,715	1,244	471
Sep-01	1,701	1,234	467
Oct-01	1,687	1,224	463
Nov-01	1,673	1,214	460
Dec-01	1,659	1,204	456
Jan-02	1,646	1,194	452
Feb-02	1,632	1,184	448
Mar-02	1,618	1,174	444
Apr-02	1,604	1,164	441
May-02	1,591	1,154	437
Jun-02	1,577	1,144	433
Jul-02	1,563	1,134	429
Aug-02	1,549	1,124	425
Sep-02	1,536	1,114	422
Oct-02	1,522	1,104	418
Nov-02	1,508	1,094	414
Dec-02	1,494	1,084	410
Jan-03	1,480	1,074	407
Feb-03	1,467	1,064	403
Mar-03	1,453	1,054	399
Apr-03	1,439	1,044	395
May-03	1,425	1,034	391
Jun-03	1,412	1,024	388
Jul-03	1,398	1,014	384
Aug-03	1,384	1,004	380
Sep-03	1,370	994	376
Oct-03	1,356	984	373
Nov-03	1,343	974	369
Dec-03	1,329	964	365
Jan-04	1,315	954	361
Feb-04	1,301	944	357

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Mar-04	1,288	934	354
Apr-04	1,274	924	350
May-04	1,260	914	346
Jun-04	1,246	904	342
Jul-04	1,233	894	339
Aug-04	1,219	884	335
Sep-04	1,205	874	331
Oct-04	1,191	864	327
Nov-04	1,177	854	323
Dec-04	1,164	844	320
Jan-05	1,150	834	316
Feb-05	1,136	824	312
Mar-05	1,122	814	308
Apr-05	1,109	804	304
May-05	1,095	794	301
Jun-05	1,081	784	297
Jul-05	1,067	774	293
Aug-05	1,054	764	289
Sep-05	1,040	754	286
Oct-05	1,026	744	282
Nov-05	1,012	734	278
Dec-05	998	724	274
Jan-06	985	714	270
Feb-06	971	704	267
Mar-06	957	694	263
Apr-06	943	684	259
May-06	930	674	255
Jun-06	916	664	252
Jul-06	902	654	248
Aug-06	888	644	244
Sep-06	874	634	240
Oct-06	861	624	236
Nov-06	847	614	233
Dec-06	833	604	229
Jan-07	819	594	225
Feb-07	806	584	221
Mar-07	792	574	217
Apr-07	778	564	214
May-07	764	554	210
Jun-07	751	544	206
Jul-07	737	534	202
Aug-07	723	524	199
Sep-07	709	514	195
Oct-07	695	504	191
Nov-07	682	494	187
Dec-07	668	484	183
Jan-08	654	474	180
Feb-08	640	464	176
Mar-08	627	455	172
Apr-08	613	445	168
May-08	599	435	165
Jun-08	585	425	161
Jul-08	572	415	157
Aug-08	558	405	153

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Sep-08	544	395	149
Oct-08	530	385	146
Nov-08	516	375	142
Dec-08	503	365	138
Jan-09	489	355	134
Feb-09	475	345	130
Mar-09	461	335	127
Apr-09	448	325	123
May-09	434	315	119
Jun-09	420	305	115
Jul-09	406	295	112
Aug-09	392	285	108
Sep-09	379	275	104
Oct-09	365	265	100
Nov-09	351	255	96
Dec-09	337	245	93
Jan-10	324	235	89
Feb-10	310	225	85
Mar-10	296	215	81
Apr-10	282	205	78
May-10	269	195	74
Jun-10	255	185	70
Jul-10	241	175	66
Aug-10	227	165	62
Sep-10	213	155	59
Oct-10	200	145	55
Nov-10	186	135	51
Dec-10	172	125	47
Jan-11	158	115	43
Feb-11	145	105	40
Mar-11	131	95	36
Apr-11	117	85	32
May-11	103	75	28
Jun-11	90	65	25
Jul-11	76	55	21
Aug-11	62	45	17
Sep-11	48	35	13
Oct-11	34	25	9
Nov-11	21	15	6
Dec-11	7	5	2
Sum	277,982	201,619	76,363

Net Trojan Plant Investment
From 3/31/1995 through 9/30/2000

Trojan Investment	**Before UE-88 Write-Off 3/31/1995**	**UE-88 Write-Off**	**UE-88 Write-Off Net Benefit Test**	**After UE-88 Write-off 3/31/1995**	**12/31/1995**	
FAS 90 Assets						
Net FAS 90 Balance	345,353,482.72	-	(22,773,056.00)	322,580,426.72	301,023,140.45	
Change in FAS 90 Balance (Amortization)	N/A			(22,773,056.00)	(21,557,286.27)	
FAS 71 Assets						
Inspection and Plugging	15,160,208.00	(15,160,208.00)		-	-	
Sleeving Costs	9,658,701.00	(9,658,701.00)		-	-	
Reactor Coolant Pump	2,162,144.00	(2,162,144.00)		-	-	
Other FAS 71 Assets	21,637,002.27		(4,054,994.00)	17,582,008.27	-	
Net FAS 71 Balance	48,618,055.27	(26,981,053.00)	(4,054,994.00)	17,582,008.27	-	
Change in FAS 71 Balance (Amortization)	N/A			(31,036,047.00)	(17,582,008.27)	Per Order 95-1216
Net Trojan Investment	**393,971,537.99**	**(26,981,053.00)**	**(26,828,050.00)**	**340,162,434.99**	**301,023,140.45**	
Change in Net Trojan Investment				**(53,809,103.00)**	**(39,139,294.54)**	

Trojan Investment	**12/31/1996**	**12/31/1997**	**12/31/1998**	**12/31/1999**	**9/30/2000**
FAS 90 Assets					
Net FAS 90 Balance	275,460,218.15	251,763,045.03	229,202,119.88	202,682,933.93	180,485,808.72
Change in FAS 90 Balance (Amortization)	(25,562,922.30)	(23,697,173.12)	(22,560,925.15)	(26,519,185.95)	(22,197,125.21)
FAS 71 Assets					
Inspection and Plugging	-	-	-	-	-
Sleeving Costs	-	-	-	-	-
Reactor Coolant Pump	-	-	-	-	-
Other FAS 71 Assets	-	-	-	-	-
Net FAS 71 Balance	-	-	-	-	-
Change in FAS 71 Balance (Amortization)					
Net Trojan Investment	**275,460,218.15**	**251,763,045.03**	**229,202,119.88**	**202,682,933.93**	**180,485,808.72**
Change in Net Trojan Investment	**(25,562,922.30)**	**(23,697,173.12)**	**(22,560,925.15)**	**(26,519,185.95)**	**(22,197,125.21)**

Summary of UE-88 Trojan Write-Off[1]
In Dollars

	3/31/95 Balance Before UE-88 Write-Off	Write-Off Post 1991 Expenditures	Write-Off Additional $20.4 million	3/31/95 Balance After UE-88 Write-Off
Trojan Investment (Pre-tax)	$ 393,971,538	$ (26,981,053)	$ (26,828,050)	$ 340,162,435
Deferred Taxes	$ (83,627,326)	$ 10,673,256	$ 6,428,050	$ (66,526,020)
Trojan Investment Tax Credits	$ (9,756,019)	$ -	$ -	$ (9,756,019)
Trojan Investment (After-tax)	$ 300,588,193	$ (16,307,797)	$ (20,400,000)	$ 263,880,396

1: After the UE-88 write-off, the pre-tax balance of Trojan, $340.2 million, was the remaining investment subject to amortization through 2011, consistent with Order 95-322.

Trojan Balances for Scenarios
Dollars in 000s

<u>For 1 year Amort Scenario - Partial Restoration</u>

Balance @ 4/1/1995	340,162
Restoration of UE-88 Net Benefit Write-off	23,108
Net Trojan	363,270

<u>For 1 year Amort Scenario - Full Restoration</u>

Balance @ 4/1/1995	340,162
Boardman Gain	(111,151)
Plant in Service	(80,200)
Restoration of UE-88 Net Benefit Write-off	26,828
Net Trojan	175,639

<u>For 17 year Amort Scenario - Full Restoration</u>

Balance @ 4/1/1995	340,162
Boardman Gain	(111,151)
Plant in Service	(80,200)
Restoration of UE-88 Net Benefit Write-off	26,828
Net Trojan	175,639

. Introduction

Q. Please state your name and position with Portland General Electric.

A. My name is Stephen M. Quennoz. I am Vice President of Generation with Portland General Electric. My qualifications appear at the end of this testimony.

My name is Leonard ("Pete") S. Peterson. I am a Federal Policy Analyst with Portland General Electric. My qualifications appear at the end of this testimony.

My name is Randy Dahlgren. I am Director of Regulatory Policy and Affairs at PGE. My qualifications appear in Section III of PGE Exhibit 6100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to review the 1995 asset classifications of Trojan for cost recovery.

Q. How is your testimony organized?

A. We first provide a description of the Staff and PGE perspectives expressed in 1994 regarding Trojan asset classification. We describe the Commission's decision concerning asset classification in Order 95-322. We then discuss how the remand of UE-88 affects those decisions and the need to re-evaluate the amount of Trojan plant remaining in service following closure. Finally, we describe how PGE determined the amount of Trojan assets that should have remained as plant-in-service.

II. Trojan Asset Classification in UE-88

Q. Please describe PGE's position regarding the Trojan asset classification for cost recovery in UE-88.

A. In 1992, PGE first identified those Trojan assets that remained in service following plant closure. In 1994, PGE testified that approximately $130 million of gross Trojan assets (approximately $80 million of net Trojan assets) continued to be used and useful and should be classified as plant-in-service (i.e., FERC account 101). PGE maintained that these assets were used and useful because "the Trojan plant remaining in FERC account 101 protects public health and safety, provides security, or provides office space and facilities for the employees remaining on site" (PGE Exhibit 2000, page 69).

Q. Which assets did PGE maintain were still in service?

A. As discussed in PGE Exhibit 900, PGE operated Trojan pursuant to a license from the NRC. Even after Trojan ceased producing electricity, a number of its systems were required by the terms of the NRC license. PGE identified the major systems still in service. These included the control, reactor auxiliary, central and fuel buildings; main control and electric board; intake structure; plant wiring; service water; fire protection; cooling water; clean radwaste treatment; gaseous radwaste treatment; instrument racks and panels, tools, equipment and fixtures; and diesel engine generators. All of these systems were still required under the terms of PGE's NRC license (PGE Exhibit 900, page 43).

Q. Did PGE provide any additional support for its position?

A. Yes. PGE provided two additional pieces as support: 1) a letter from the Chief Accountant at FERC that approved PGE's proposed Trojan asset classification; and 2) a copy of the Report of Independent Public Accountants that certified the accuracy of PGE's FERC-based financial reporting, which included the Trojan assets as plant-in-service. We have included the appropriate work papers as PGE Exhibit 6301.

Q. Did Staff agree with PGE's position?

A. No. Staff argued that the referenced assets were needed primarily for decommissioning and were a result of past, not current operations of the plant. Consequently, Staff maintained that no Trojan assets were used and useful and all such assets should be classified as regulatory assets in FERC account 182.2.

Q. What did the Commission decide on this issue?

A. The Commission ultimately agreed with Staff and specified that "All Trojan plant investment…should be transferred to FERC Account 182.2, Unrecovered Plant and Regulatory and Regulatory Study Costs" (Order No. 95-322, page 54).

Q. Did any other factors influence the Commission's decision regarding Trojan asset classification?

A. Yes. At the time of its decision in UE-88, the Commission was relying on the framework of its earlier decision in DR 10. Specifically, the Commission believed that it could provide both the recovery of, and a return on, plant no longer in service, as long as these could be demonstrated to be in the public interest. Given this framework, the Commission decision on asset classification was largely an accounting issue. It had no impact on the rates that were set in UE-88.

Q. What did Staff and the Commission say?

A. Both Staff and the Commission observed that because both FERC accounts 101 and 182.2 are in rate base, "transferring investment between the accounts will not affect the rate base" (Staff Exhibit 66, page 3 and Commission Order No. 95-322, page 53).

III. Implications of UE-88 Remand

Q. Does the remand of UE-88 impact the Commission's decision regarding Trojan asset classification?

A. Yes. In light of the court's interpretation of ORS 757.355, the Commission should reconsider its analysis. Following the 1995 decision, PGE earned a return on plant assets in both accounting classifications, so the distinction between the two was not necessarily material. Now, however, the classification has a direct impact on PGE's rate base and the ratemaking treatment that follows from that decision.

Q. How does ORS 757.355 describe assets eligible to earn a return on investment?

A. The statute provides that "A public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer" (ORS 757.355(1)).

Q. How is "service" defined in this context?

A. ORS 756.010(8) defines service broadly. "'Service' is used in the *broadest and most inclusive sense* and includes equipment and facilities related to providing the service or the product served" (ORS 756.010(8) italics added for emphasis).

Q. Did the Commission rely upon ORS 756.010(8) and a broad definition of service in deciding the asset classification issue in UE-88?

A. We do not believe the Commission did. From the language in Order 95-322, it appears that the Commission defined "service" narrowly. The Commission stated, "As Staff notes, however, the original purpose of the assets in question was to be part of an operating plant that was providing service to ratepayers. This plant has now been permanently shut down, and those assets are now used only to provide the service necessary for safety and asset preservation pending decommissioning and dismantling of the plant" (OPUC Order No. 95-322, page 53).

Q. Did Staff and the Commission rely on any other authorities to determine that the Trojan was not plant-in-service?

A. Yes, Staff and the Commission cited Federal Accounting Standards Board (FASB) Statement No. 90 which states "When it becomes probable that an operating asset… will be abandoned, the cost of that asset shall be removed from…plant-in-service" (Staff Exhibit 66, page 5).

Q. Was Trojan abandoned in 1995?

A. No. The plant was far from abandoned in 1995 because it was in the early stages of a long and complicated decommissioning process. Further, neither Staff nor the Commission explicitly disagreed with PGE's method to identify Trojan plant-in service. In fact, Staff audited PGE's analysis and work papers and their testimony took no exception to our results. Ultimately, the Commission agreed that the referenced assets were providing service (OPUC Order No. 95-322, page 53).

Q. Are these assets necessary to protect the public health and safety?

A. Yes. These assets provide necessary service, required both before the Trojan plant was shut down and during decommissioning.

IV. Determining Asset Classification

Q. How did PGE determine which Trojan assets continued to provide service?

A. Beginning in 1992, PGE conducted an analysis to determine Trojan plant-in-service. PGE was required to accurately record Trojan assets on PGE's books and financial statements using FERC accounting standards. PGE requested and received approval from the FERC Chief Accountant for its treatment of Trojan plant-in-service (see PGE Exhibit 6301). This detailed analysis was reviewed and updated regularly through 1994 to reflect Trojan activities and PGE's understanding of the asset usage (see 1992-1994, PGE FERC Form 1, page 205, lines 17-23, provided as PGE Exhibit 6302).

Q. What was the value of Trojan plant-in-service?

A. In 1992, PGE identified $130 million gross Trojan plant-in-service (approximately $80 million net Trojan assets) following the plant closure. PGE's ongoing analysis through 1994 indicated that the value of gross Trojan plant-in-service was $150 million following the plant closure. We utilized the $130 million figure in the UE-88 rate case because, as Staff and the Commission noted, "transferring investment between the accounts will not affect the rate base" (Staff Exhibit 66, page 3 and Commission Order No. 95-322, page 53).

Q. Has PGE updated this work?

A. Yes. While the analysis of 1992-1994 was very rigorous, PGE believed that by using the same methodology, but with the experience of numerous years of decommissioning effort, we might identify a different level of Trojan plant-in-service. This value could be higher than the $80 million identified in 1992 or it could be lower. To this end, we have reviewed all Trojan assets as of 1995 and identified which ones were in fact used and useful during the following years. We relied on the same criteria that existed in 1995. Details of the analysis are provided as PGE Exhibit 6303. We identified $214.5 million gross plant-in-service and $113.6 million net plant-in-service.

Q. How, specifically, did you identify the $113.6 million?

A. We evaluated a detailed listing of Trojan assets that reflected plant balances on PGE's books in 1995 (see PGE Exhibit 6303). We performed an asset-by-asset review to determine what, if any, service the asset provided for safety, environmental protection, and/or decommissioning. If we concluded that some or all of an asset provided legitimate service, we then determined what percent of that asset should be counted as in service.

Q. Please explain.

A. If we determined an entire asset was in service, it was listed as 100 percent. If we concluded that only part of an asset was in service, we had to make a subsequent determination regarding the percent to apply. If an asset had distinct components that allowed its use to be clearly separated by function, then we applied a percent that reflected that partial use (*e.g.*, laboratory equipment and office furniture). If an asset was not realistically separable, such as the water system described in Staff Exhibit 66, pages 6-7, then it was counted as 100 percent. Several managers at the Trojan plant then reviewed our analysis. We, and the managers who prepared and reviewed this list, have decades of experience at the Trojan plant and are confident in our expert understanding of the plant's operations.

Q. Did PGE use the same process in 1992-1994 to determine Trojan plant-in-service?

A. Yes. We utilized the same process as described above. We reviewed system-level investment detail and established applicable percentages based on the whether an asset or portion of an asset provided service. If a portion of an asset provided service, we then established whether the asset's functionality was separable. If so, we applied a percent that reflected that partial use. If not, we listed the asset at 100 percent.

Q. Do you believe the current analysis is more accurate than the 1992-1994 evaluation?

A. Yes, but the current analysis is developed with hindsight. It demonstrates that the original $80 million net plant-in-service value developed in 1992 was quite reasonable. Our update supports the use of $80 million for net Trojan plant that was then presently used for utility service in UE-88.

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, General Manager at the Arkansas Nuclear One Station for Arkansas Power and Light, and Restart Manager at 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. I've held my current position of Vice President, Generation since December 2000. My responsibilities include overseeing the operations of PGE's thermal and hydro plants 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. Peterson, please describe your qualifications.

A. I have 29 years of experience in the nuclear industry, including 24 years in support of the operation and decommissioning of the Trojan Nuclear Plant. Among my decommissioning duties, I was the cost control engineer for the large component removal, reactor vessel and internals removal, and Independent Spent Fuel Storage Installation projects. In 1972, I received a Bachelors of Science in Engineering Physics from the University of Illinois, and in 1973, I obtained a Masters of Science in Nuclear Engineering from the same school. I am a registered Professional Engineer and am currently enrolled in the Graduate Certificate

Program in Applied Energy Economics and Policy at Portland State University. I am now a Federal Policy Analyst in PGE's Federal Regulatory Affairs Department.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
6301	UE-88 PGE Rebuttal Work papers - Trojan Investment Classification
6302	PGE FERC Form 1 – 1992 - 1994, Pages 204-205
6303	Current Analysis of Trojan Asset Classification

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
ADMIN BLDG,BLDG FRAME 8150-140-020	152,594.13	$	103,001.04	100%	$	103,001.04	The Admin Bldg was used for records storage and housed communications equipment. The structure also contained a small amount of asbestos-containing material.
ADMIN BLDG,COMMUNICATIONS EQUIP 8150-140-010	553,309.10	$	373,483.64	100%	$	373,483.64	Communication System used to support plant
ADMIN BLDG,EXCAVATION 8150-140-006	4,549.01	$	3,070.58	100%	$	3,070.58	
ADMIN BLDG,EXTERIOR WALLS 8150-140-040	178,916.96	$	120,768.95	100%	$	120,768.95	
ADMIN BLDG,FENCING 8150-140-175	46,540.65	$	31,414.94	0%	$	-	Fencing was not used.
ADMIN BLDG,FIRE PROTECTION SYSTEM 8150-140-130	18,987.53	$	12,816.58	100%	$	12,816.58	
ADMIN BLDG,FLOORS AND FLOOR COVERINGS 8150-140-030	26,090.20	$	17,610.89	100%	$	17,610.89	
ADMIN BLDG,HVAC 8150-140-120	301,908.58	$	203,788.29	100%	$	203,788.29	
ADMIN BLDG,IN-PLANT COMMUNICATION EQUIP 8150-140-125	15,222.40	$	10,275.12	100%	$	10,275.12	Communications system was used.
ADMIN BLDG,INTERIOR WALLS AND CEILINGS 8150-140-050	45,321.60	$	30,592.08	100%	$	30,592.08	
ADMIN BLDG,LIGHTING 8150-140-110	106,942.94	$	72,186.48	100%	$	72,186.48	
ADMIN BLDG,PLUMBING 8150-140-090	54,350.04	$	36,686.28	100%	$	36,686.28	
ADMIN BLDG,ROOFING GUTTERS DOWNSPOUTS 8150-140-060	26,154.39	$	17,654.21	100%	$	17,654.21	
ADMIN BLDG,STRUCTURAL MATERIAL 8150-140-008	651,339.92	$	439,654.45	100%	$	439,654.45	
CENTRAL BLDG,BLDG ELECTRICAL 8150-135-100	995,797.82	$	672,163.53	100%	$	672,163.53	
CENTRAL BLDG,BLDG FRAME 8150-135-020	2,126,960.02	$	1,435,698.01	100%	$	1,435,698.01	The Central Bldg was the main office building on-site and housed required radiation protection, decommissioning, operations, quality assurance, licensing and security personnel. As such, the structure and supporting systems and components were required.
CENTRAL BLDG,BLDG LIGHTING 8150-135-110	426.90	$	288.16	100%	$	288.16	
CENTRAL BLDG,BLDG PLUMBING 8150-135-090	254,495.32	$	171,784.34	100%	$	171,784.34	
CENTRAL BLDG,CABINETS, SHELVES & COUNTERS 8150-135-140	116,405.00	$	78,573.38	100%	$	78,573.38	
CENTRAL BLDG,COMMUNICATION EQUIP 8150-135-010	1,129,849.52	$	762,648.43	100%	$	762,648.43	
CENTRAL BLDG,COMPUTER EQUIP 8150-135-645	183,370.28	$	123,774.94	66%	$	81,691.46	Staffing reduction
CENTRAL BLDG,ELEVATOR 8150-135-144	98,475.10	$	66,470.69	100%	$	66,470.69	
CENTRAL BLDG,EXTERIOR WALLS 8150-135-040	65,988.93	$	44,542.53	100%	$	44,542.53	
CENTRAL BLDG,FIRE PROTECTION SYSTEM 8150-135-130	141,964.05	$	95,825.73	100%	$	95,825.73	
CENTRAL BLDG,FLOOR & FLOOR COVERINGS 8150-135-030	722,360.29	$	487,593.20	100%	$	487,593.20	
CENTRAL BLDG,FURNITURE & OFC EQUIP 8150-135-120	2,429,148.21	$	1,639,675.04	66%	$	1,082,185.53	Staffing reduction
CENTRAL BLDG,IN-PLANT COMMUNICATIONS EQUIP 8150-135-125	47,560.35	$	32,103.24	100%	$	32,103.24	
CENTRAL BLDG,INSTRUMENTS RACKS AND PANELS 8150-135-256	2,310.59	$	1,559.65	100%	$	1,559.65	
CENTRAL BLDG,INTERIOR WALLS & CEILINGS 8150-135-050	1,025,369.44	$	692,124.37	100%	$	692,124.37	
CENTRAL BLDG,LANDSCAPING 8150-135-011	48,226.75	$	32,553.06	0%	$	-	No longer necessary
CENTRAL BLDG,ROADS, ROADWAYS, AND PARKING LOTS 8150-135-035	105,498.00	$	71,211.15	100%	$	71,211.15	
CENTRAL BLDG,ROOFING, GUTTERS & DOWNSPOUTS 8150-135-060	262,650.27	$	177,288.93	100%	$	177,288.93	
CENTRAL BLDG,SECURITY SYSTEM 8150-135-123	57,917.05	$	39,094.01	100%	$	39,094.01	
CENTRAL BLDG,SEWAGE DISPOSAL SYSTEM 8150-135-080	94,454.79	$	63,756.98	100%	$	63,756.98	
CONDENSATE DEMINERALIZER BLDG,480-V AUXILIARY SYSTEM 8150-260-618	18,272.68	$	12,334.06	100%	$	12,334.06	The Condensate Demineralizer Bldg contained a small amount of radioactive material, and was extensively used in subsequent years as a radioactive waste processing facility. The structure itself and support systems were necessary radiological barriers.
CONDENSATE DEMINERALIZER BLDG,BLDG FRAME 8150-260-020	399,420.97	$	269,609.15	100%	$	269,609.15	
CONDENSATE DEMINERALIZER BLDG,CARD KEY ACCESS SYSTEM 8150-260-911	16,178.31	$	10,920.36	100%	$	10,920.36	
CONDENSATE DEMINERALIZER BLDG,CONDENSATE DEMINERALIZER SYSTEM 8150-260-434	3,612,622.51	$	2,438,520.19	0%	$	-	No longer used
CONDENSATE DEMINERALIZER BLDG,CRANES & HOISTS 8150-260-805	51,702.06	$	34,898.89	100%	$	34,898.89	
CONDENSATE DEMINERALIZER BLDG,ELECTRICAL SYSTEM 8150-260-001	836,312.45	$	564,510.90	100%	$	564,510.90	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
CONDENSATE DEMINERALIZER BLDG,EXCAVATION 8150-260-006	5,775.38	$	3,898.38	100%	$	3,898.38	
CONDENSATE DEMINERALIZER BLDG,EXTERIOR WALLS 8150-260-040	1,534,027.39	$	1,035,468.49	100%	$	1,035,468.49	
CONDENSATE DEMINERALIZER BLDG,FIRE PROTECTION SYSTEM 8150-260-130	40,534.53	$	27,360.81	100%	$	27,360.81	
CONDENSATE DEMINERALIZER BLDG,FLOORS AND FLOOR COVERINGS 8150-260-030	20,565.80	$	13,881.92	100%	$	13,881.92	
CONDENSATE DEMINERALIZER BLDG,FOUNDATION AND BASE SLAB 8150-260-010	311,640.78	$	210,357.53	100%	$	210,357.53	
CONDENSATE DEMINERALIZER BLDG,HVAC 8150-260-120	173,318.31	$	116,989.86	100%	$	116,989.86	
CONDENSATE DEMINERALIZER BLDG,INTERIOR WALLS 8150-260-050	17,113.51	$	11,551.62	100%	$	11,551.62	
CONDENSATE DEMINERALIZER BLDG,LIGHTING AND CONTROLS 8150-260-110	36,795.20	$	24,836.76	100%	$	24,836.76	
CONDENSATE DEMINERALIZER BLDG,PAINTING 8150-260-070	1,171.03	$	790.45	100%	$	790.45	
CONDENSATE DEMINERALIZER BLDG,PLUMBING 8150-260-090	112,985.84	$	76,265.44	100%	$	76,265.44	
CONDENSATE DEMINERALIZER BLDG,ROOFS GUTTERS DOWNSPOUTS 8150-260-060	24,201.15	$	16,335.78	100%	$	16,335.78	
CONDENSATE DEMINERALIZER BLDG,STRUCTURAL MATERIAL 8150-260-008	68,148.27	$	46,000.08	100%	$	46,000.08	
CONTROL BLDG,12.5KV AUXILIARY SYSTEM 8150-300-616	51,829.47	$	34,984.89	100%	$	34,984.89	The Control Building housed the main control room, electrical switchgear & distribution rooms, controlled access points for security and radiation protection purposes, mechanical and computer rooms, and the control and instrumentation shop.
CONTROL BLDG,120-V AC INSTRUMENT SYSTEM 8150-300-630	457,026.34	$	308,492.78	100%	$	308,492.78	Included were electrical power, instrumentation and control systems necessary for Spent Fuel Pool cooling and radiation monitoring.
CONTROL BLDG,4160-V AUXILIARY SYSTEM 8150-300-617	28,544.32	$	19,267.42	100%	$	19,267.42	
CONTROL BLDG,480-V AUXILIARY SYSTEM 8150-300-618	197,668.03	$	133,425.92	100%	$	133,425.92	
CONTROL BLDG,ACCOUSTIC LEAK MONITOR SYSTEM 8150-300-445	264,890.89	$	178,801.35	0%	$	-	No longer used
CONTROL BLDG,AUXILIARY FEEDWATER SYSTEM 8150-300-432	348,600.45	$	235,305.30	0%	$	-	No longer used
CONTROL BLDG,CABINETS SHELVES AND COUNTERS 8150-300-140	928,971.42	$	627,055.71	100%	$	627,055.71	
CONTROL BLDG,CARD KEY ACCESS SYSTEM 8150-300-911	190,317.92	$	128,464.60	100%	$	128,464.60	
CONTROL BLDG,CIRCULATING WATER SYSTEM 8150-300-435	41,916.25	$	28,293.47	0%	$	-	No longer used
CONTROL BLDG,COMMUNICATIONS EQUP 8150-300-010	457,951.19	$	309,117.05	100%	$	309,117.05	The main control room was required to be manned 24 hours a day by the Nuclear Regulatory Commission in order to monitor the spent fuel pool and take action if necessary.
CONTROL BLDG,COMPONENT COOLING WATER SYSTEM 8150-300-216	497,954.09	$	336,119.01	0%	$	-	No longer used
CONTROL BLDG,COMPUTER EQUIP (TOC ANALYZER) 8150-300-645	5,454,469.80	$	3,681,767.12	100%	$	3,681,767.12	
CONTROL BLDG,CONTROL ROD DRIVE POWER 8150-300-635	5,564.61	$	3,756.11	0%	$	-	No longer used
CONTROL BLDG,DC ELECTRICAL SYSTEM 8150-300-620	1,271,111.90	$	858,000.53	100%	$	858,000.53	DC system necessary for elect. Control pwr
CONTROL BLDG,DEMINERALIZER SYSTEM 8150-300-243	35,911.18	$	24,240.05	0%	$	-	No longer used
CONTROL BLDG,DIESEL FUEL OIL SYSTEM 8150-300-626	78,272.67	$	52,834.05	0%	$	-	No longer used
CONTROL BLDG,ELEVATORS 8150-300-144	118,264.03	$	79,828.22	100%	$	79,828.22	
CONTROL BLDG,EXCAVATION 8150-300-006	20,688.11	$	13,964.47	100%	$	13,964.47	
CONTROL BLDG,EXTERIOR WALLS 8150-300-040	2,448,694.73	$	1,652,868.94	100%	$	1,652,868.94	
CONTROL BLDG,FIRE PROTECTION EQUIP 8150-300-130	5,755,942.58	$	3,885,261.24	100%	$	3,885,261.24	
CONTROL BLDG,FIXED AREA RADIATION MONITOR 8150-300-260	12,482.83	$	8,425.91	100%	$	8,425.91	
CONTROL BLDG,FLOORS AND FLOOR COVERINGS 8150-300-030	199,126.42	$	134,410.33	100%	$	134,410.33	
CONTROL BLDG,FURNITURE & OFC EQUIP 8150-300-100	167,122.37	$	112,807.60	100%	$	112,807.60	
CONTROL BUILDING,BLDG FRAME 8150-300-020	2,208,672.14	$	1,490,853.69	100%	$	1,490,853.69	
CONTROL BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-300-425	205,802.65	$	138,916.79	100%	$	138,916.79	
CONTROL BUILDING,IN-PLANT COMMUNICATIONS EQUIP 8150-300-125	136,980.77	$	92,462.02	100%	$	92,462.02	
CONTROL BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-300-810	80,142.60	$	54,096.26	100%	$	54,096.26	
CONTROL BUILDING,INSTRUMENTATION AND CONTROL 8150-300-261	1,572,621.26	$	1,061,519.35	40%	$	424,607.74	
CONTROL BUILDING,INSTRUMENTS RACKS & PANELS 8150-300-460	1,265,374.17	$	854,127.56	40%	$	341,651.03	
CONTROL BUILDING,INTEGRATED LEAK RATE TESTING SYSTEM 8150-300-257	80,863.23	$	54,582.68	0%	$	-	No longer used
CONTROL BUILDING,INTERIOR WALLS AND CEILINGS 8150-300-050	757,841.86	$	511,543.26	100%	$	511,543.26	
CONTROL BUILDING,LAB EQUIPMENT 8150-300-134	322,896.37	$	217,955.05	40%	$	87,182.02	
CONTROL BUILDING,LADDERS AND STAIRWAYS 8150-300-013	81,613.35	$	55,089.01	100%	$	55,089.01	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
CONTROL BUILDING,LIGHTING AND CONTROLS 8150-300-110	1,123,399.31	$	758,294.53	100%	$	758,294.53	
CONTROL BUILDING,MAIN CONTROL & ELECTRIC BOARD 8150-300-640	12,144,189.24	$	8,197,327.74	40%	$	3,278,931.09	
CONTROL BUILDING,METEOROLOGY INSTRUMENTS 8150-300-220	52,799.43	$	35,639.62	100%	$	35,639.62	
CONTROL BUILDING,MISC GAS SUPPLY SYSTEM 8150-300-815	387,069.75	$	261,272.08	50%	$	130,636.04	Used Nitrogen and sample gasses
CONTROL BUILDING,NSSS COMPUTER 8150-300-269	1,016,406.04	$	686,074.08	0%	$	-	
CONTROL BUILDING,PLUMBING 8150-300-090	874,215.47	$	590,095.44	100%	$	590,095.44	
CONTROL BUILDING,POWER SYSTEMS 8150-300-265	400,493.57	$	270,333.16	100%	$	270,333.16	
CONTROL BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-300-262	646,876.16	$	436,641.41	100%	$	436,641.41	All radiation monitors still in service
CONTROL BUILDING,PROCESS SAMPLING SYSTEM 8150-300-267	154,846.48	$	104,521.37	10%	$	10,452.14	
CONTROL BUILDING,PROCESS STEAM SYSTEM 8150-300-422	8,444.45	$	5,700.00	0%	$	-	No longer used
CONTROL BUILDING,REACTOR CONTROL AND PROTECTION SYSTEM 8150-300-264	1,116,727.04	$	753,790.75	0%	$	-	No longer used
CONTROL BUILDING,REACTOR CONTROLS 8150-300-212	9,934.35	$	6,705.69	0%	$	-	No longer used
CONTROL BUILDING,REMOTE SHUTDOWN STATION 8150-300-680	10,204,594.97	$	6,888,101.60	0%	$	-	No longer used
CONTROL BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-300-060	81,275.14	$	54,860.72	100%	$	54,860.72	
CONTROL BUILDING,SECURITY EQUIPMENT 8150-300-120	11,569,440.96	$	7,809,372.65	100%	$	7,809,372.65	
CONTROL BUILDING,SECURITY EQUIPMENT 8150-300-123	2,712,061.80	$	1,830,641.72	100%	$	1,830,641.72	
CONTROL BUILDING,SERVICE WATER SYSTEM 8150-300-440	1,359,272.76	$	917,509.11	100%	$	917,509.11	
CONTROL BUILDING,STATION AND AREA RADIATION MONITORING EQUIP 8150-300-135	1,140,805.93	$	770,044.00	100%	$	770,044.00	
CONTROL BUILDING,STORES EQUIPMENT 8150-300-138	1,850.00	$	1,248.75	40%	$	499.50	
CONTROL BUILDING,STRUCTURAL MATERIAL 8150-300-008	241,624.11	$	163,096.27	100%	$	163,096.27	
CONTROL BUILDING,TOOLS & EQUIPMENT 8150-300-136	310,223.53	$	209,400.88	40%	$	83,760.35	
CONTROL BUILDING,TURBINE-GENERATOR CONTROL PANEL 8150-300-407	12,894.76	$	8,703.96	0%	$	-	No longer used
CONTROL BUILDING,UNDISTRIBUTED PROPERTY 8150-300-001	370,488.24	$	250,079.56	0%	$	-	
COOLING TOWER,AVIATION WARNING LIGHTS 8150-340-060	174,908.44	$	118,063.20	100%	$	118,063.20	Tower height made it an aviation hazard
COOLING TOWER,BASIN AND OUTLET STRUCTURE 8150-340-020	926,216.14	$	625,195.89	100%	$	625,195.89	The cooling tower structure contained asbestos-containing fill material that required cleanup to protect the safety of the public.
COOLING TOWER,CIRCULATING WATER SYSTEM 8150-340-435	62,396.10	$	42,117.37	0%	$	-	
COOLING TOWER,COMMUNICATIONS EQUIPMENT 8150-340-010	855,151.89	$	577,227.53	100%	$	577,227.53	
COOLING TOWER,CONDENSATE SYSTEM 8150-340-430	22,144.94	$	14,947.83	0%	$	-	
COOLING TOWER,FILL AND FILL SUPPORTS 8150-340-093	3,641,798.67	$	2,458,214.10	100%	$	2,458,214.10	Asbestos-containing material (the cooling tower fill material) remained in 1995 and had to be removed and disposed of safely.
COOLING TOWER,INSTRUMENTS RACKS AND PANELS 8150-340-460	16,978.69	$	11,460.62	0%	$	-	
COOLING TOWER,MECHANICAL FACILITIES 8150-340-419	499,877.83	$	337,417.54	0%	$	-	
COOLING TOWER,TOWER SUPPORTS AND VEIL 8150-340-030	3,740,477.23	$	2,524,822.13	100%	$	2,524,822.13	The cooling tower structure contained asbestos-containing fill material that required cleanup to protect the safety of the public.
COOLING TOWER,WATER PIPING SYSTEM 8150-340-090	240,390.78	$	162,263.78	0%	$	-	
DECHLORINATION BUILDING,BUILDING FRAME 8150-280-020	4,572.15	$	3,086.20	100%	$	3,086.20	Dechlorination required by NPDES permit before discharge into the Columbia River.
DECHLORINATION BUILDING,DOMESTIC WATER SYSTEM 8150-280-451	6,429.42	$	4,339.86	100%	$	4,339.86	
DECHLORINATION BUILDING,EXCAVATION 8150-400-006	2,150.82	$	1,451.80	100%	$	1,451.80	
DECHLORINATION BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-400-120	10,167.93	$	6,863.35	100%	$	6,863.35	
DECHLORINATION BUILDING,LADDERS AND STAIRWAYS 8150-400-013	7,380.65	$	4,981.94	100%	$	4,981.94	
DECHLORINATION BUILDING,LIGHTING AND CONTROLS 8150-280-110	21,092.68	$	14,237.56	100%	$	14,237.56	
DECHLORINATION BUILDING,MISC GAS SUPPLY SYSTEM 8150-280-815	1,178.14	$	795.24	100%	$	795.24	
DECHLORINATION BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-400-060	484.40	$	326.97	100%	$	326.97	
DECHLORINATION BUILDING,STRUCTURAL MATERIAL 8150-400-008	25,379.28	$	17,131.01	100%	$	17,131.01	
FIRE EXTINGUISHERS,COMPANY NUMBER 6000 - 6999 8150-050-006	2,182.84	$	1,473.42	100%	$	1,473.42	Fire protection required for personnel safety and to prevent spread of radioactive material.
FIRE EXTINGUISHERS,COMPANY NUMBERS 0000-0999 8150-050-980	6,344.51	$	4,282.54	100%	$	4,282.54	
FIRE EXTINGUISHERS,COMPANY NUMBERS 03000-03999 8150-050-003	46,136.52	$	31,142.15	100%	$	31,142.15	
FIRE EXTINGUISHERS,COMPANY NUMBERS 04000-04999 8150-050-004	8,891.40	$	6,001.70	100%	$	6,001.70	
FIRE EXTINGUISHERS,COMPANY NUMBERS 05000-05999 8150-050-005	13,511.72	$	9,120.41	100%	$	9,120.41	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
FIRE EXTINGUISHERS,COMPANY NUMBERS 1000-1999 8150-050-001	2,022.56	$	1,365.23	100%	$	1,365.23	
FIRE EXTINGUISHERS,COMPANY NUMBERS 7000 - 7999 8150-050-007	1,912.41	$	1,290.88	100%	$	1,290.88	
FIRE EXTINGUISHERS,FIRE EXTINGUISHER, NO COMPANY NUMBER 8150-050-999	1,335.77	$	901.64	100%	$	901.64	
FISH REARING FACILITIES,CONTROL WIRING 8150-040-490	9,927.12	$	6,700.81	0%	$	-	No longer used.
FISH REARING FACILITIES,HEAT TRACING SYSTEM 8150-040-648	59,956.66	$	40,470.75	0%	$	-	
FISH REARING FACILITIES,INSTRUMENTS RACKS AND PANELS 8150-040-256	64,726.07	$	43,690.10	0%	$	-	
FISH REARING FACILITIES,SITE AND YARD DEVELOPMENT 8150-040-412	115,688.04	$	78,089.43	0%	$	-	
FISH REARING FACILITIES,WARM WATER SUPPLY 8150-040-444	1,077,688.05	$	727,439.43	0%	$	-	
FUEL BUILDING,480-V AUXILIARY SYSTEM 8150-220-618	6,130.41	$	4,138.03	100%	$	4,138.03	The Fuel Bldg contained the Spent Fuel Pool (which contained spent nuclear fuel), radiation and pool leakage monitoring equipment, and other support systems for the spent fuel pool.
FUEL BUILDING,AUXILIARY STEAM SYSTEM 8150-220-421	2,513.06	$	1,696.32	0%	$	-	Not used.
FUEL BUILDING,BUILDING FRAME 8150-220-020	1,484,790.61	$	1,002,233.66	100%	$	1,002,233.66	The Fuel Bldg also contained radioactively contaminated rooms and equipment, radioactive waste storage and treatment equipment, and asbestos containing material, all of which had to be contained.
FUEL BUILDING,CABINETS SHELVES AND COUNTERS 8150-220-140	97,934.84	$	66,106.02	100%	$	66,106.02	
FUEL BUILDING,CARD KEY ACCESS SYSTEM 8150-220-911	32,960.40	$	22,248.27	100%	$	22,248.27	
FUEL BUILDING,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-220-224	2,711,354.10	$	1,830,164.02	0%	$	-	Not used.
FUEL BUILDING,CIRCULATING WATER SYSTEM 8150-220-435	95,509.65	$	64,469.01	0%	$	-	Not used.
FUEL BUILDING,CLEAN RADWASTE TREATMENT SYSTEM 8150-220-250	1,337,112.45	$	902,550.90	100%	$	902,550.90	
FUEL BUILDING,COMPONENT COOLING WATER SYSTEM 8150-220-216	2,661,538.30	$	1,796,538.35	100%	$	1,796,538.35	Used for the SFP Cooling
FUEL BUILDING,CONTAINMENT SPRAY SYSTEM 8150-220-227	519,069.35	$	350,371.81	0%	$	-	Not used.
FUEL BUILDING,CRANES & HOISTS 8150-220-805	465,262.13	$	314,051.94	100%	$	314,051.94	The Fuel Bldg also contained equipment, tools and spare parts necessary for removing the spent fuel from the pool and into radiation shielding casks.
FUEL BUILDING,DECONTAMINATION SYSTEM 8150-220-255	541,120.39	$	365,256.26	100%	$	365,256.26	
FUEL BUILDING,DEMINERALIZER SYSTEM 8150-220-243	141,643.63	$	95,609.45	20%	$	19,121.89	Rad. Waste and SFP cooling demins.
FUEL BUILDING,DIESEL FUEL OIL SYSTEM 8150-220-626	60,752.10	$	41,007.67	0%	$	-	Not used.
FUEL BUILDING,DOMESTIC WATER SYSTEM 8150-220-451	40,512.39	$	27,345.86	100%	$	27,345.86	
FUEL BUILDING,EXCAVATION 8150-220-006	10,969.80	$	7,404.62	100%	$	7,404.62	
FUEL BUILDING,EXTERIOR WALLS 8150-220-040	789,462.01	$	532,886.86	100%	$	532,886.86	
FUEL BUILDING,FENCING 8150-220-175	404,477.74	$	273,022.47	100%	$	273,022.47	
FUEL BUILDING,FIRE PROTECTION EQUIPMENT 8150-220-130	1,048,024.70	$	707,416.67	100%	$	707,416.67	
FUEL BUILDING,FIXED AREA RADIATION MONITOR SYSTEM 8150-220-260	13,149.21	$	8,875.72	100%	$	8,875.72	
FUEL BUILDING,FLOORS AND FLOOR COVERINGS 8150-220-030	703,047.01	$	474,556.73	100%	$	474,556.73	
FUEL BUILDING,FOUNDATIONS 8150-220-010	22,682.82	$	15,310.90	100%	$	15,310.90	
FUEL BUILDING,FUEL BUILDING HEAT AND VENT SYSTEM 8150-220-229	123,843.94	$	83,594.66	100%	$	83,594.66	
FUEL BUILDING,FUEL HANDLING AND STORAGE EQUIPMENT 8150-220-231	112,424.77	$	75,886.72	100%	$	75,886.72	
FUEL BUILDING,GASEOUS RADWASTE TREATMENT SYSTEM 8150-220-252	268,173.79	$	181,017.31	0%	$	-	Not used.
FUEL BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-220-120	1,855,889.15	$	1,252,725.18	100%	$	1,252,725.18	
FUEL BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-220-425	91,021.48	$	61,439.50	100%	$	61,439.50	
FUEL BUILDING,IN-PLANT COMMUNICATION EQUIP. 8150-220-125	1,925.17	$	1,299.49	100%	$	1,299.49	
FUEL BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-220-810	1,681,755.58	$	1,135,185.02	50%	$	567,592.51	
FUEL BUILDING,INSTRUMENTS RACKS & PANELS 8150-220-460	82,356.88	$	55,590.89	50%	$	27,795.45	
FUEL BUILDING,INSTRUMENTS RACKS AND PANELS 8150-220-256	1,027,735.57	$	693,721.51	50%	$	346,860.75	
FUEL BUILDING,INTERIOR WALLS AND CEILING 8150-220-050	1,610,483.03	$	1,087,076.05	100%	$	1,087,076.05	
FUEL BUILDING,LADDERS AND STAIRWAYS 8150-220-013	7,484.20	$	5,051.84	100%	$	5,051.84	
FUEL BUILDING,LIGHTING AND CONTROLS 8150-220-110	280,252.68	$	189,170.56	100%	$	189,170.56	
FUEL BUILDING,MAKE-UP WATER TREATMENT SYSTEM 8150-220-446	24,694.20	$	16,668.59	50%	$	8,334.29	Used for CCW and SFP makeup
FUEL BUILDING,MISC GAS SUPPLY SYSTEM 8150-220-815	147,636.16	$	99,654.41	30%	$	29,896.32	Used for CCW Nitrogen
FUEL BUILDING,PLUMBING 8150-220-090	97,946.04	$	66,113.58	100%	$	66,113.58	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
FUEL BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-220-225	59,084.40 $	39,881.97	0% $	-	Not used.
FUEL BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-220-245	106,663.02 $	71,997.54	0% $	-	Not used.
FUEL BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-220-262	5,057.99 $	3,414.14	100% $	3,414.14	
FUEL BUILDING,PROCESS SAMPLING SYSTEM 8150-220-267	100,794.45 $	68,036.25	20% $	13,607.25	
FUEL BUILDING,PROCESS STEAM SYSTEM 8150-220-422	652,375.15 $	440,353.23	0% $	-	Not used.
FUEL BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-220-060	36,477.49 $	24,622.31	100% $	24,622.31	
FUEL BUILDING,SAFETY INJECTION SYSTEM 8150-220-214	27,434.17 $	18,518.06	0% $	-	Not used.
FUEL BUILDING,SERVICE WATER SYSTEM 8150-220-440	1,681,374.68 $	1,134,927.91	50% $	567,463.95	
FUEL BUILDING,SOLID RADWASTE TREATMENT SYSTEM 8150-220-253	429,572.68 $	289,961.56	0% $	-	Not used.
FUEL BUILDING,SPENT FUEL POOL COOLING SYSTEM 8150-220-233	1,645,599.82 $	1,110,779.88	100% $	1,110,779.88	
FUEL BUILDING,STORES EQUIPMENT 8150-220-138	6,345.99 $	4,283.54	100% $	4,283.54	
FUEL BUILDING,STRUCTURAL MATERIAL 8150-220-008	130,816.51 $	88,301.14	100% $	88,301.14	
FUEL BUILDING,TOOLS & EQUIPMENT 8150-220-136	122,594.77 $	82,751.47	100% $	82,751.47	
FUEL BUILDING,TOOLS EQUIPMENT AND FIXTURES 8150-220-232	4,639,984.70 $	3,131,989.67	100% $	3,131,989.67	
GUARDHOUSE,120 8150-070-120	353,896.24 $	238,879.96	100% $	238,879.96	Security-related. Security protect the public from the theft of radioactive material and terrorist activities.
GUARDHOUSE,BUILDING FRAME 8150-070-020	39,232.11 $	26,481.67	100% $	26,481.67	
GUARDHOUSE,CABINETS SHELVES & COUNTERS 8150-070-140	33,820.75 $	22,829.01	100% $	22,829.01	
GUARDHOUSE,CARD KEY ACCESS SYSTEM 8150-070-911	1,299,672.57 $	877,278.98	100% $	877,278.98	
GUARDHOUSE,COMMUNICATIONS EQUIPMENT 8150-070-010	124,714.54 $	84,182.31	100% $	84,182.31	
GUARDHOUSE,EXTERIOR WALLS 8150-070-040	202,780.05 $	136,876.53	100% $	136,876.53	
GUARDHOUSE,FLOOR & FLOOR COVERINGS 8150-070-030	19,515.79 $	13,173.16	100% $	13,173.16	
GUARDHOUSE,FURNITURE & OFFICE EQUIPMENT 8150-070-100	29,230.99 $	19,730.92	100% $	19,730.92	
GUARDHOUSE,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-070-125	18,310.07 $	12,359.30	100% $	12,359.30	
GUARDHOUSE,INTERIOR WALLS & CEILINGS 8150-070-050	1,720,305.72 $	1,161,206.36	100% $	1,161,206.36	
GUARDHOUSE,LIGHTING 8150-070-110	86,007.45 $	58,055.03	100% $	58,055.03	
GUARDHOUSE,PLUMBING 8150-070-090	16,853.12 $	11,375.86	100% $	11,375.86	
GUARDHOUSE,ROOFING GUTTERS DOWNSPOUTS 8150-070-060	11,781.49 $	7,952.51	100% $	7,952.51	
GUARDHOUSE,SECURITY EQUIPMENT 8150-070-123	2,006,017.41 $	1,354,061.75	100% $	1,354,061.75	
IN PLANT COMMUNICATION SYSTEM,IN PLANT COMMUNICATION EQUIPMENT 8150-333-125	1,822,545.06 $	1,230,217.92	100% $	1,230,217.92	Necessary for required plant operations.
INTAKE STRUCTURE,480-V AUXILIARY SYSTEM 8150-360-618	161,209.77 $	108,816.59	100% $	108,816.59	The Intake Structure included structures, equipment and components for taking water from the Columbia River and pumping it into the plant for cooling purposes (including the spent fuel) and for fire protection.
INTAKE STRUCTURE,BUILDING FRAME 8150-360-020	26,152.59 $	17,653.00	100% $	17,653.00	
INTAKE STRUCTURE,CARD KEY ACCESS SYSTEM 8150-360-911	16,480.20 $	11,124.14	100% $	11,124.14	
INTAKE STRUCTURE,CHLORINATION SYSTEM 8150-360-447	188,922.14 $	127,522.44	50% $	63,761.22	Using the Sodium Hypochlorinate for Serv. Water
INTAKE STRUCTURE,CIRCULATING WATER SYSTEM 8150-360-435	241,070.63 $	162,722.68	0% $	-	
INTAKE STRUCTURE,CRANES & HOISTS 8150-360-805	19,047.32 $	12,856.94	100% $	12,856.94	
INTAKE STRUCTURE,DIESEL FUEL OIL SYSTEM 8150-360-626	60,977.43 $	41,159.77	100% $	41,159.77	
INTAKE STRUCTURE,EXCAVATION 8150-360-006	8,605.46 $	5,808.69	100% $	5,808.69	
INTAKE STRUCTURE,EXTERIOR WALLS 8150-360-040	44,593.26 $	30,100.45	100% $	30,100.45	
INTAKE STRUCTURE,FIRE PROTECTION EQUIPMENT 8150-360-130	642,981.31 $	434,012.38	100% $	434,012.38	
INTAKE STRUCTURE,FOUNDATION AND BASE SLAB 8150-360-010	767,172.88 $	517,841.69	100% $	517,841.69	
INTAKE STRUCTURE,FURNITURE & OFFICE EQUIPMENT 8150-360-100	508.03 $	342.92	100% $	342.92	
INTAKE STRUCTURE,HEAT VENTILATING AND AIR CONDITIONING 8150-360-120	73,279.94 $	49,463.96	100% $	49,463.96	
INTAKE STRUCTURE,INSTRUMENT & SERVICE AIR SYSTEM 8150-360-810	180,591.74 $	121,899.42	100% $	121,899.42	
INTAKE STRUCTURE,INSTRUMENTS RACKS AND PANELS 8150-360-256	110,430.21 $	74,540.39	100% $	74,540.39	
INTAKE STRUCTURE,INSTRUMENTS RACKS AND PANELS 8150-360-460	76,986.18 $	51,965.67	100% $	51,965.67	
INTAKE STRUCTURE,INTAKE SCREEN WASH SYSTEM 8150-360-450	414,095.07 $	279,514.17	100% $	279,514.17	
INTAKE STRUCTURE,LIGHTING AND CONTROLS 8150-360-110	201,921.22 $	136,296.82	100% $	136,296.82	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
INTAKE STRUCTURE,MAKE-UP WATER TREATMENT SYSTEM 8150-360-446	119,427.43	$	80,613.52	100%	$	80,613.52	Makup to SFP and CCW
INTAKE STRUCTURE,MECHANICAL FACILITIES 8150-360-419	451,786.95	$	304,956.19	100%	$	304,956.19	
INTAKE STRUCTURE,PLUMBING 8150-360-090	7,961.90	$	5,374.28	100%	$	5,374.28	
INTAKE STRUCTURE,ROOFS GUTTERS DOWNSPOUTS 8150-360-060	6,564.80	$	4,431.24	100%	$	4,431.24	
INTAKE STRUCTURE,SECURITY EQUIPMENT 8150-360-123	14.40	$	9.72	100%	$	9.72	
INTAKE STRUCTURE,SERVICE WATER SYSTEM 8150-360-440	884,692.30	$	597,167.30	100%	$	597,167.30	
INTAKE STRUCTURE,STRUCTURAL MATERIAL 8150-360-008	101,542.79	$	68,541.38	100%	$	68,541.38	
INTANGIBLE PLANT,COMPUTER SOFTWARE 8150-005-003	13,604,788.91	$	9,183,232.51	10%	$	918,323.25	Some of the intangibles (e.g., computer software) were used for radiation protection and security purposes.
LABORATORY EQUIPMENT,COMPANY NUMBERS 10000-10999 8150-500-010	146,918.80	$	99,170.19	75%	$	74,377.64	Used for analyzing required radioactive and non-radioactive (e.g., residual chlorine in discharge) samples
LABORATORY EQUIPMENT,COMPANY NUMBERS 1000-1999 8150-500-001	193,143.29	$	130,371.72	75%	$	97,778.79	
LABORATORY EQUIPMENT,COMPANY NUMBERS 11000-11999 8150-500-011	161,940.39	$	109,309.76	75%	$	81,982.32	
LABORATORY EQUIPMENT,COMPANY NUMBERS 16000-16999 8150-500-016	384.90	$	259.81	75%	$	194.86	
LABORATORY EQUIPMENT,COMPANY NUMBERS 2000-2999 8150-500-002	3,174.49	$	2,142.78	75%	$	1,607.09	
LABORATORY EQUIPMENT,COMPANY NUMBERS 3000-3999 8150-500-003	632.71	$	427.08	75%	$	320.31	
LABORATORY EQUIPMENT,COMPANY NUMBERS 4000-4999 8150-500-004	26,127.24	$	17,635.89	75%	$	13,226.92	
LABORATORY EQUIPMENT,COMPANY NUMBERS 5000-5999 8150-500-005	50,803.17	$	34,292.14	75%	$	25,719.10	
LABORATORY EQUIPMENT,COMPANY NUMBERS 6000-6999 8150-500-006	105,899.19	$	71,481.95	75%	$	53,611.46	
LABORATORY EQUIPMENT,COMPANY NUMBERS 7000-7999 8150-500-007	429,526.32	$	289,930.27	75%	$	217,447.70	
LABORATORY EQUIPMENT,COMPANY NUMBERS 8000-8999 8150-500-008	356,463.36	$	240,612.77	75%	$	180,459.58	
LABORATORY EQUIPMENT,COMPANY NUMBERS 9000-9999 8150-500-009	261,847.41	$	176,747.00	75%	$	132,560.25	
LABORATORY EQUIPMENT,COMPANY NUMBERS EQUAL TO ZERO 8150-500-020	1,319,450.94	$	890,629.38	75%	$	667,972.04	
LABORATORY EQUIPMENT,COMPANY NUMBERS LESS THAN 1000 8150-500-100	149,520.23	$	100,926.16	75%	$	75,694.62	
LABORATORY EQUIPMENT,STORE ISSUE TICKET ITEMS NOT NUMBERED 8150-500-101	104,822.75	$	70,755.36	75%	$	53,066.52	
LIQUID/STEEL STORAGE WAREHOUSE,OUTSIDE FACILITIES 8150-255-020	143,763.29	$	97,040.22	100%	$	97,040.22	Hazardous materials and metals that would be used later on in decommissioning activities were stored here.
LOWER COLUMBIA RIVER LABORATORY,240-V AUXILIARY SYSTEM 8150-090-510	5,842.03	$	3,943.37	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,COMMUNICATIONS EQUIPMENT 8150-090-010	1,016.88	$	686.39	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,EXTERIOR WALLS 8150-090-040	20,387.63	$	13,761.65	100%	$	13,761.65	Structure needed because building contained asbestos-containing material.
LOWER COLUMBIA RIVER LABORATORY,FLOORS AND FLOOR COVERINGS 8150-090-030	4,272.05	$	2,883.63	100%	$	2,883.63	
LOWER COLUMBIA RIVER LABORATORY,FOUNDATION AND BASE SLAB 8150-090-012	6,555.76	$	4,425.14	100%	$	4,425.14	
LOWER COLUMBIA RIVER LABORATORY,FURNITURE & OFFICE EQUIPMENT 8150-090-100	34,915.16	$	23,567.73	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-090-125	2,396.56	$	1,617.68	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,LAB EQUIPMENT 8150-090-134	31,749.26	$	21,430.75	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,MISCELLANEOUS BUILDING EQUIPMENT 8150-090-199	38,485.50	$	25,977.71	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,OUTSIDE FACILITIES 8150-090-006	45,012.53	$	30,383.46	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,PARTITIONS AND CEILINGS 8150-090-050	44,614.71	$	30,114.93	0%	$	-	Not used.
LOWER COLUMBIA RIVER LABORATORY,PLUMBING 8150-090-090	65,561.04	$	44,253.70	0%	$	-	
LOWER COLUMBIA RIVER LABORATORY,ROOFS GUTTERS AND DOWNSPOUTS 8150-090-060	15,787.22	$	10,656.37	100%	$	10,656.37	
LOWER COLUMBIA RIVER LABORATORY,STORES EQUIPMENT 8150-090-138	477.17	$	322.09	0%	$	-	
MAIN STEAM SUPPORT STRUCTURE (MSSS),AUXILIARY FEEDWATER SYSTEM 8150-245-432	105,239.73	$	71,036.82	0%	$	-	
MAIN STEAM SUPPORT STRUCTURE (MSSS),EXTERIOR WALLS 8150-245-040	104,165.15	$	70,311.48	100%	$	70,311.48	Structure needed; small area contaminated.
MAIN STEAM SUPPORT STRUCTURE (MSSS),LADDERS AND STAIRWAYS 8150-245-013	279,825.86	$	188,882.46	100%	$	188,882.46	Structure needed; small area contaminated.
MAIN STEAM SUPPORT STRUCTURE (MSSS),MAIN CONTROL AND ELECTRIC BOARD 8150-245-640	424,253.44	$	286,371.07	100%	$	286,371.07	Essent. All electrically sys. Still in service
MAIN STEAM SUPPORT STRUCTURE (MSSS),PLUMBING 8150-245-090	6,358.13	$	4,291.74	100%	$	4,291.74	All drains still in service
MAINTENANCE CONTRACTORS SHOP,BUILDING FRAME 8150-155-020	469,830.68	$	317,135.71	100%	$	317,135.71	Maintenance shops were needed for decommissioning activities.
MAINTENANCE CONTRACTORS SHOP,ELECTRICAL SYSTEM 8150-155-100	9,454.78	$	6,381.98	100%	$	6,381.98	
MAINTENANCE CONTRACTORS SHOP,HEAT VENTILATING & AIR CONDITIONING 8150-155-120	9,259.89	$	6,250.43	100%	$	6,250.43	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
MAINTENANCE SHOP,COMPUTER EQUIPMENT 8150-150-645	47,799.95	$	32,264.97	100%	$	32,264.97	Maintenance shops were needed for decommissioning activities.
MAINTENANCE SHOP,CRANES & HOISTS 8150-150-805	9,120.13	$	6,156.09	100%	$	6,156.09	
MAINTENANCE SHOP,FURNITURE AND OFFICE EQUIPMENT 8150-150-100	10,765.95	$	7,267.02	100%	$	7,267.02	
MAINTENANCE SHOP,IN-PLANT COMMUNICATION EQUIP. 8150-150-125	853.38	$	576.03	100%	$	576.03	
MAINTENANCE SHOP,LAB EQUIPMENT 8150-150-134	11,915.62	$	8,043.04	100%	$	8,043.04	
MAINTENANCE SHOP,MORE TOOLS & EQUIPMENT 8150-150-137	460,809.11	$	311,046.15	100%	$	311,046.15	
MAINTENANCE SHOP,STORES EQUIPMENT 8150-150-138	10,132.70	$	6,839.57	100%	$	6,839.57	
MAINTENANCE SHOP,TOOLS & EQUIPMENT 8150-150-136	1,150,606.64	$	776,659.48	100%	$	776,659.48	
METEOROLOGY YARD,ACCESS ROAD-METEOROLOGY TOWER 8150-080-300	4,551.76	$	3,072.44	100%	$	3,072.44	The met. Tower still in service with reduced function.
METEOROLOGY YARD,FENCING 8150-080-175	604.89	$	408.30	100%	$	408.30	
METEOROLOGY YARD,INSTRUMENT BUILDING 8150-080-060	3,134.81	$	2,116.00	100%	$	2,116.00	
METEOROLOGY YARD,METEOROLOGY INSTRUMENTS 8150-080-220	243,907.44	$	164,637.52	25%	$	41,159.38	
METEOROLOGY YARD,METEOROLOGY TOWER & EQUIPMENT 8150-080-250	2,497.88	$	1,686.07	100%	$	1,686.07	
METEOROLOGY YARD,METEOROLOGY TOWER 8150-080-200	32,595.49	$	22,001.96	100%	$	22,001.96	
METEOROLOGY YARD,METEOROLOGY TOWER LIGHTING 8150-080-230	42,782.52	$	28,878.20	100%	$	28,878.20	
METEOROLOGY YARD,METEOROLOGY YARD 8150-080-010	519.07	$	350.37	100%	$	350.37	
MOBILE AREA,CELLULAR TELEPHONES 8150-330-020	13,238.93	$	8,936.28	0%	$	-	
MOBILE AREA,COMMUNICATIONS EQUIPMENT 8150-330-010	21,799.82	$	14,714.88	0%	$	-	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),BUILDING FRAME 8150-425-020	105,563.80	$	71,255.57	100%	$	71,255.57	Facility used for asset recovery and document storage. Comm. System still in service
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),CABINETS SHELVES AND COUNTERS 8150-425-140	72,013.81	$	48,609.32	0%	$	-	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),COMMUNICATIONS SYSTEM 8150-425-010	1,098,269.97	$	741,332.23	100%	$	741,332.23	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),COMPUTER EQUIPMENT 8150-425-645	64,192.55	$	43,329.97	100%	$	43,329.97	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),ELEVATORS 8150-425-144	46,947.05	$	31,689.26	100%	$	31,689.26	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),EXTERIOR WALLS 8150-425-040	74,651.22	$	50,389.57	100%	$	50,389.57	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),FIRE PROTECTION EQUIPMENT 8150-425-130	231,282.57	$	156,115.73	100%	$	156,115.73	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),FLOORS AND FLOOR COVERINGS 8150-425-030	738,530.34	$	498,507.98	100%	$	498,507.98	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),FURNITURE AND OFFICE EQUIPMENT 8150-425-100	1,002,085.73	$	676,407.87	0%	$	-	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),HEAT VENTILATING AND AIR CONDITIONING 8150-425-120	1,164,393.73	$	785,965.77	100%	$	785,965.77	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),IN-PLANT COMMUNICATIONS EQUIPMENT 8150-425-125	65,682.56	$	44,335.73	100%	$	44,335.73	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),INTERIOR WALLS AND CEILINGS 8150-425-050	758,766.53	$	512,167.41	100%	$	512,167.41	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),LADDERS AND STAIRWAYS 8150-425-013	104,942.39	$	70,836.11	100%	$	70,836.11	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),ROOFS GUTTERS DOWNSPOUTS 8150-425-060	148,025.04	$	99,916.90	100%	$	99,916.90	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),SEWAGE DISPOSAL SYSTEM 8150-425-080	8,781.96	$	5,927.82	100%	$	5,927.82	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),STRUCTURAL MATERIAL 8150-425-008	696,786.33	$	470,330.77	100%	$	470,330.77	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),TELEPHONE COMMUNICATION 8150-425-019	425,043.59	$	286,904.42	100%	$	286,904.42	
OFFICE EQUIPMENT,1992/1993 MASS PROPERTY PER PRESTON 8150-520-092	2,525,782.68	$	1,704,903.31	20%	$	340,980.66	Portion used for security, radiation protection, operations, quality assurance , Independent Fuel Storage Installation (ISFSI) project and decommissioning personnel.
OFFICE EQUIPMENT,COMPANY NUMBERS 1000 - 1999 8150-520-010	786.64	$	530.98	20%	$	106.20	(Reduced as a percentage of personnel on-site. Roughly 200 out of 1000 or more.)
OFFICE EQUIPMENT,COMPANY NUMBERS 11000-11999 8150-520-111	9,514.30	$	6,422.15	20%	$	1,284.43	
OFFICE EQUIPMENT,COMPANY NUMBERS 12000-12999 8150-520-112	756.00	$	510.30	20%	$	102.06	
OFFICE EQUIPMENT,COMPANY NUMBERS 14000-14999 8150-520-400	698.00	$	471.15	20%	$	94.23	
OFFICE EQUIPMENT,COMPANY NUMBERS 15000-15999 8150-520-150	1,119.00	$	755.33	20%	$	151.07	
OFFICE EQUIPMENT,COMPANY NUMBERS 5000-5999 8150-520-050	752,786.44	$	508,130.85	20%	$	101,626.17	
OFFICE EQUIPMENT,COMPANY NUMBERS 6000 - 6999 8150-520-060	169,830.23	$	114,635.41	20%	$	22,927.08	
OFFICE EQUIPMENT,COMPANY NUMBERS 8000-8999 8150-520-080	4,208.79	$	2,840.93	20%	$	568.19	
OFFICE EQUIPMENT,COMPANY NUMBERS 9000-9999 8150-520-090	14,746.47	$	9,953.87	20%	$	1,990.77	
OFFICE EQUIPMENT,OFFICE EQUIPMENT, NO COMPANY NUMBER 8150-520-999	1,972,366.76	$	1,331,347.56	20%	$	266,269.51	
OFFICE FURNITURE,COMPANY NUMBERS 0001-0999 8150-510-005	44,141.59	$	29,795.57	20%	$	5,959.11	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
OFFICE FURNITURE,COMPANY NUMBERS 1000-1999 8150-510-010	134,242.40	$	90,613.62	20%	$	18,122.72	
OFFICE FURNITURE,COMPANY NUMBERS 2000-2999 8150-510-020	16,766.92	$	11,317.67	20%	$	2,263.53	
OFFICE FURNITURE,COMPANY NUMBERS 3000-3999 8150-510-030	117,756.71	$	79,485.78	20%	$	15,897.16	
OFFICE FURNITURE,COMPANY NUMBERS 4000-4999 8150-510-040	17,618.65	$	11,892.59	20%	$	2,378.52	
OFFICE FURNITURE,COMPANY NUMBERS 5000-5999 8150-510-050	46,798.69	$	31,589.12	20%	$	6,317.82	
OFFICE FURNITURE,FURNITURE, NO COMPANY NUMBER 8150-510-999	424,841.41	$	286,767.95	20%	$	57,353.59	
OFFICE FURNITURE,MASS PROPERTY ITEMS 8150-510-998	1,195,596.50	$	807,027.64	20%	$	161,405.53	
OLD WAREHOUSE,TOOLS AND EQUIPMENT 8150-250-136	249,728.68	$	168,566.86	50%	$	84,283.43	Portion of old WSH Warehouse used for ISFSI project and packaging area for LCR project.
ON-SITE WAREHOUSE (NEW),BUILDING FRAME 8150-445-020	832,948.25	$	562,240.07	100%	$	562,240.07	Warehouse used for parts and material shipment receipt for decommissioning activities.
ON-SITE WAREHOUSE (NEW),COMPUTER EQUIPMENT 8150-445-645	41,783.30	$	28,203.73	100%	$	28,203.73	
ON-SITE WAREHOUSE (NEW),EXCAVATION 8150-445-006	69,418.42	$	46,857.43	100%	$	46,857.43	
ON-SITE WAREHOUSE (NEW),FOUNDATION AND BASE SLAB 8150-445-010	1,145,792.24	$	773,409.76	100%	$	773,409.76	
ON-SITE WAREHOUSE (NEW),FURNITURE & OFFICE EQUIPMENT 8150-445-100	2,106.74	$	1,422.05	100%	$	1,422.05	
ON-SITE WAREHOUSE (NEW),STOREROOM EQUIPMENT 8150-445-138	649,684.17	$	438,536.81	100%	$	438,536.81	Warehouse used for parts and material shipment receipt for decommissioning activities.
OUTSIDE FACILITIES,12.5-KV AUXILIARY SYSTEM 8150-020-617	182,299.18	$	123,051.95	100%	$	123,051.95	Switchyard was necessary for electrical power, barge facilities were needed for barge shipments of radioactive components, fire protection equipment was necessary, domestic water was needed for plant personnel.
OUTSIDE FACILITIES,4160-V AUXILIARY SYSTEM 8150-020-616	133,985.79	$	90,440.41	100%	$	90,440.41	
OUTSIDE FACILITIES,480-V AUXILIARY SYSTEM 8150-020-618	12,460.06	$	8,410.54	100%	$	8,410.54	
OUTSIDE FACILITIES,AUXILIARY FEEDWATER SYSTEM 8150-020-432	233,167.51	$	157,388.07	0%	$	-	
OUTSIDE FACILITIES,BARGE UNLOADING BASIN 8150-020-034	272,584.43	$	183,994.49	100%	$	183,994.49	
OUTSIDE FACILITIES,CATHODIC PROTECTION SYSTEM 8150-020-650	677,399.25	$	457,244.49	100%	$	457,244.49	
OUTSIDE FACILITIES,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-020-224	265,388.52	$	179,137.25	0%	$	-	
OUTSIDE FACILITIES,CHLORINATION SYSTEM 8150-020-447	257,584.03	$	173,869.22	0%	$	-	
OUTSIDE FACILITIES,CIRCULATING WATER SYSTEM 8150-020-435	5,550,061.87	$	3,746,291.76	0%	$	-	
OUTSIDE FACILITIES,CLEAN RADWASTE TREATMENT SYSTEM 8150-020-250	208,660.75	$	140,846.01	100%	$	140,846.01	
OUTSIDE FACILITIES,COMMUNICATIONS EQUIPMENT 8150-020-010	2,263,746.28	$	1,528,028.74	100%	$	1,528,028.74	
OUTSIDE FACILITIES,CONDENSATE SYSTEM 8150-020-430	360,323.68	$	243,218.48	0%	$	-	
OUTSIDE FACILITIES,DECHLORINATION SYSTEM 8150-020-448	379,888.41	$	256,424.68	100%	$	256,424.68	
OUTSIDE FACILITIES,DIESEL FUEL OIL SYSTEM 8150-020-626	671,685.75	$	453,387.88	0%	$	-	
OUTSIDE FACILITIES,DOMESTIC WATER SYSTEM 8150-020-451	1,791,948.00	$	1,209,564.90	100%	$	1,209,564.90	System used to support decom. Act., CCW, SFP, all site facilities, etc.
OUTSIDE FACILITIES,FENCING 8150-020-175	801,125.53	$	540,759.73	100%	$	540,759.73	
OUTSIDE FACILITIES,FIRE PROTECTION EQUIPMENT 8150-020-130	751,530.76	$	507,283.26	100%	$	507,283.26	
OUTSIDE FACILITIES,GENERATOR COOLING AND VENT SYSTEM 8150-020-570	30,000.03	$	20,250.02	0%	$	-	
OUTSIDE FACILITIES,GROUNDING SYSTEM 8150-020-655	263,136.88	$	177,617.39	100%	$	177,617.39	
OUTSIDE FACILITIES,GROUNDS EQUIPMENT 8150-020-610	3,928.76	$	2,651.91	100%	$	2,651.91	
OUTSIDE FACILITIES,GUARD TOWERS 8150-020-037	1,432,705.81	$	967,076.42	0%	$	-	Not used.
OUTSIDE FACILITIES,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-020-425	245,067.40	$	165,420.50	100%	$	165,420.50	
OUTSIDE FACILITIES,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-020-125	134,913.88	$	91,066.87	100%	$	91,066.87	
OUTSIDE FACILITIES,INSTRUMENT & SERVICE AIR SYSTEM 8150-020-810	666,046.18	$	449,581.17	100%	$	449,581.17	
OUTSIDE FACILITIES,INSTRUMENTS RACKS AND PANELS 8150-020-460	255,889.41	$	172,725.35	30%	$	51,817.61	
OUTSIDE FACILITIES,ISOLATED PHASE BUS 8150-020-200	331,634.55	$	223,853.32	0%	$	-	
OUTSIDE FACILITIES,LADDERS AND STAIRWAYS 8150-020-013	194,351.75	$	131,187.43	100%	$	131,187.43	
OUTSIDE FACILITIES,LAND & LAND RIGHTS 8150-020-005	840,663.36	$	567,447.77	100%	$	567,447.77	
OUTSIDE FACILITIES,LANDSCAPING 8150-020-011	1,002.16	$	676.46	0%	$	-	
OUTSIDE FACILITIES,LIGHTING AND CONTROLS 8150-020-110	202,708.51	$	136,828.24	100%	$	136,828.24	
OUTSIDE FACILITIES,MAIN STEAM SYSTEM 8150-020-420	5,556,423.29	$	3,750,585.72	0%	$	-	
OUTSIDE FACILITIES,MAKE-UP WATER TREATMENT SYSTEM 8150-020-446	1,346,671.36	$	909,003.17	100%	$	909,003.17	System used to support decom. Act., CCW, SFP, all site facilities, etc.

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
OUTSIDE FACILITIES,METEOROLOGICAL MONITORING-KALAMA WASH 8150-020-139	6,061.30	$	4,091.38	0%	$	-	
OUTSIDE FACILITIES,METEOROLOGICAL MONITORING-KELSO WASH 8150-020-135	2,948.30	$	1,990.10	0%	$	-	
OUTSIDE FACILITIES,MISCELLANEOUS 8150-020-900	256,964.68	$	173,451.16	30%	$	52,035.35	
OUTSIDE FACILITIES,OREGON STATE HIGHWAY 8150-020-029	63,183.57	$	42,648.91	100%	$	42,648.91	
OUTSIDE FACILITIES,PRIMARY MAKE-UP WATER SYSTEM 8150-020-225	335,534.07	$	226,485.50	0%	$	-	
OUTSIDE FACILITIES,PROCESS STEAM SYSTEM 8150-020-422	26,496.47	$	17,885.12	0%	$	-	
OUTSIDE FACILITIES,RAILROAD SPURS 8150-020-032	239.27	$	161.51	0%	$	-	
OUTSIDE FACILITIES,ROADWAYS AND PARKING 8150-020-030	2,036,638.88	$	1,374,731.24	100%	$	1,374,731.24	
OUTSIDE FACILITIES,SAFETY INJECTION SYSTEM 8150-020-214	533,079.40	$	359,828.60	0%	$	-	
OUTSIDE FACILITIES,SECURITY EQUIPMENT 8150-020-120	3,090,156.22	$	2,085,855.45	100%	$	2,085,855.45	Security required for protection against security threats.
OUTSIDE FACILITIES,SERVICE WATER SYSTEM 8150-020-440	3,778,166.83	$	2,550,262.61	100%	$	2,550,262.61	
OUTSIDE FACILITIES,SEWAGE DISPOSAL SYSTEM 8150-020-080	1,992,403.90	$	1,344,872.63	100%	$	1,344,872.63	The sewage treatment system protected the environment.
OUTSIDE FACILITIES,SIGNS 8150-020-520	110,873.98	$	74,839.94	100%	$	74,839.94	
OUTSIDE FACILITIES,SIRENS AND RERP RELATED EQUIP. TAX CD. 218 8150-020-905	926,003.07	$	625,052.07	0%	$	-	
OUTSIDE FACILITIES,START-UP BOILER BLDG 8150-020-040	51,916.88	$	35,043.89	0%	$	-	
OUTSIDE FACILITIES,TELEPHONE COMMUNICATIONS 8150-020-019	475,149.75	$	320,726.08	100%	$	320,726.08	
OUTSIDE FACILITIES,TRAILER FACILITIES INSIDE PROTECTED AREA 8150-020-015	282,144.54	$	190,447.56	0%	$	-	Not used.
OUTSIDE FACILITIES,UNDERGROUND DUCTWAYS 8150-020-670	635,977.01	$	429,284.48	100%	$	429,284.48	
OUTSIDE FACILITIES,UNDISTRIBUTED PROPERTY CHARGE 8150-020-001	395,203.50	$	266,762.36	0%	$	-	
OUTSIDE FACILITIES,UNDISTRIBUTED PROPERTY CHARGE 8150-020-002	0.61	$	0.41	0%	$	-	
OUTSIDE FACILITIES,VEHICLE GATE GUARDHOUSE 8150-020-036	6,152.91	$	4,153.21	100%	$	4,153.21	
OUTSIDE FACILITIES,WIRE LINE TERMINAL EQUIPMENT 8150-020-020	367,697.31	$	248,195.68	100%	$	248,195.68	
OUTSIDE FACILITIES,YARD AND MISC STRUCTURE MATERIAL 8150-020-007	1,095,334.05	$	739,350.48	100%	$	739,350.48	
OUTSIDE FACILITIES,YARD AREA LIGHTING 8150-020-510	523,100.10	$	353,092.57	100%	$	353,092.57	
OUTSIDE FACILITIES,YARD LOOP DISTRIBUTION SYSTEM 8150-020-490	531,276.16	$	358,611.41	100%	$	358,611.41	
PLANT COMPUTER EQUIPMENT,COMPUTER EQUIPMENT 8150-390-645	740,055.75	$	499,537.63	10%	$	49,953.76	A portion was used for monitoring the spent fuel pool and radioactive waste treatment systems.
PLANT COMPUTER EQUIPMENT,COMPUTER FURNITURE 8150-390-644	902.00	$	608.85	10%	$	60.89	
PLANT WIRING & ACCESSORIES,4160-V AUXILIARY SYSTEM 8150-380-617	3,270.86	$	2,207.83	100%	$	2,207.83	Essent. All electrically sys. Still in service to support functional plant systems, support decom., lighting, etc.
PLANT WIRING & ACCESSORIES,480-V AUXILIARY SYSTEM 8150-380-618	3,331.26	$	2,248.60	100%	$	2,248.60	
PLANT WIRING & ACCESSORIES,CABLE CONNECTIONS 8150-380-015	427,261.15	$	288,401.28	100%	$	288,401.28	
PLANT WIRING & ACCESSORIES,CABLE FIREPROOFING & BARRIERS 8150-380-012	107,209.83	$	72,366.64	100%	$	72,366.64	
PLANT WIRING & ACCESSORIES,CABLE TRAYS 8150-380-011	1,410,330.47	$	951,973.07	100%	$	951,973.07	
PLANT WIRING & ACCESSORIES,CARD KEY ACCESS SYSTEM 8150-380-911	102,167.54	$	68,963.09	100%	$	68,963.09	
PLANT WIRING & ACCESSORIES,CONDUIT & TUBING 8150-380-010	1,116,513.19	$	753,646.40	100%	$	753,646.40	
PLANT WIRING & ACCESSORIES,ELECTRICAL SYSTEMS 8150-380-999	19,543,101.61	$	13,191,593.59	100%	$	13,191,593.59	
PLANT WIRING & ACCESSORIES,ELECTRICAL TESTING 8150-380-017	302,251.19	$	204,019.55	100%	$	204,019.55	
PLANT WIRING & ACCESSORIES,EXCAVATION 8150-380-006	602.54	$	406.71	100%	$	406.71	
PLANT WIRING & ACCESSORIES,FIRE PROTECTION SYSTEM 8150-380-130	2,957,098.85	$	1,996,041.72	100%	$	1,996,041.72	
PLANT WIRING & ACCESSORIES,FIRE-RATED CABLE WRAP SYSTEM 8150-380-005	734,958.87	$	496,097.24	100%	$	496,097.24	
PLANT WIRING & ACCESSORIES,GROUND CABLE 8150-380-016	355,050.06	$	239,658.79	100%	$	239,658.79	
PLANT WIRING & ACCESSORIES,HEAT TRACING SYSTEM 8150-380-648	90,413.93	$	61,029.40	100%	$	61,029.40	
PLANT WIRING & ACCESSORIES,IN-PLANT COMMUNICATION & ALARM 8150-380-125	3,683.44	$	2,486.32	100%	$	2,486.32	
PLANT WIRING & ACCESSORIES,LIGHTING AND CONTROLS 8150-380-110	90,010.12	$	60,756.83	100%	$	60,756.83	
PLANT WIRING & ACCESSORIES,MAIN CONTROL & ELECTRIC BOARD 8150-380-640	4,956.35	$	3,345.54	100%	$	3,345.54	
PLANT WIRING & ACCESSORIES,ROOFS GUTTERS DOWNSPOUTS 8150-380-060	135.68	$	91.58	100%	$	91.58	
PLANT WIRING & ACCESSORIES,STRUCTURAL MATERIAL 8150-380-008	7,109.94	$	4,799.21	100%	$	4,799.21	
PLANT WIRING & ACCESSORIES,TERMINAL & PULL BOXES 8150-380-013	82,199.90	$	55,484.93	100%	$	55,484.93	
PLANT WIRING & ACCESSORIES,UNDISTRIBUTED PROPERTY CHARGE 8150-380-001	1,202,885.67	$	811,947.83	100%	$	811,947.83	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
PLANT WIRING & ACCESSORIES,WIRE & CABLE 8150-380-014	4,277,515.47	$	2,887,322.94	25%	$	721,830.74	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,COMPUTER EQUIPMENT 8150-700-645	16,696.97	$	11,270.45	0%	$	-	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,FURNITURE AND OFFICE EQUIPMENT 8150-700-100	2,886.32	$	1,948.27	0%	$	-	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,LABORATORY EQUIPMENT 8150-700-134	58,017.53	$	39,161.83	0%	$	-	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,SIRENS AND RERP RELATED EQUIPMENT 8150-700-905	464,333.23	$	313,424.93	0%	$	-	
RADWASTE ANNEX BUILDING,TOOLS AND EQUIPMENT 8150-235-136	3,095.48	$	2,089.45	100%	$	2,089.45	Used to store radioactive material.
RADWASTE ANNEX FACILITY,DOMESTIC WATER SYSTEM 8150-225-451	20,212.47	$	13,643.42	100%	$	13,643.42	
RADWASTE ANNEX FACILITY,ELECTRICAL SYSTEM 8150-225-100	30,631.97	$	20,676.58	100%	$	20,676.58	
RADWASTE ANNEX FACILITY,EXTERIOR WALLS 8150-225-040	245,951.27	$	166,017.11	100%	$	166,017.11	
RADWASTE ANNEX FACILITY,FIRE PROTECTION 8150-225-130	26,106.77	$	17,622.07	100%	$	17,622.07	
RADWASTE ANNEX FACILITY,FLOORS AND FLOOR COVERINGS 8150-225-030	79,894.07	$	53,928.50	100%	$	53,928.50	
RADWASTE ANNEX FACILITY,HEAT VENTILATING AND AIR CONDITIONING 8150-225-120	106,765.89	$	72,066.98	100%	$	72,066.98	
RADWASTE ANNEX FACILITY,HOISTS AND CRANES 8150-225-805	10,365.17	$	6,996.49	100%	$	6,996.49	
RADWASTE ANNEX FACILITY,INSTRUMENT RACKS AND PANELS 8150-225-256	2,080.70	$	1,404.47	100%	$	1,404.47	
RADWASTE ANNEX FACILITY,INTERIOR WALLS AND CEILINGS 8150-225-050	15,118.00	$	10,204.65	100%	$	10,204.65	
RADWASTE ANNEX FACILITY,LIGHTING AND CONTROLS 8150-225-110	66,643.03	$	44,984.05	100%	$	44,984.05	
RADWASTE ANNEX FACILITY,PLUMBING 8150-225-090	63,994.28	$	43,196.14	100%	$	43,196.14	
RADWASTE ANNEX FACILITY,ROOFS GUTTERS AND DOWNSPOUTS 8150-225-060	211,742.56	$	142,926.23	100%	$	142,926.23	
RADWASTE ANNEX FACILITY,STRUCTURAL MATERIAL 8150-225-008	152,469.65	$	102,917.01	100%	$	102,917.01	
RADWASTE ANNEX FACILITY,TOOLS AND EQUIPMENT 8150-225-136	161,076.00	$	108,726.30	100%	$	108,726.30	
RAINIER COMMUNICATION STA.,COMMUNICATION EQUIPMENT 8150-455-010	4,852.44	$	3,275.40	100%	$	3,275.40	Part of the communications system to offsite locals.
REACTOR AUXILIARY BUILDING,480-V AUXILIARY SYSTEM 8150-200-618	84,052.83	$	56,735.66	100%	$	56,735.66	The Auxiliary Bldg housed the spent fuel pool cooling system, radioactive waste treatment systems, the radioactive sample (hot) lab, many radioactive components and contaminated areas.
REACTOR AUXILIARY BUILDING,BUILDING FRAME 8150-200-020	3,596,542.20	$	2,427,665.99	100%	$	2,427,665.99	
REACTOR AUXILIARY BUILDING,CAPITALIZED INSPECTIONS 8150-200-710	2,109,779.46	$	1,424,101.14	100%	$	1,424,101.14	
REACTOR AUXILIARY BUILDING,CARD KEY ACCESS SYSTEM 8150-200-911	245,024.71	$	165,391.68	100%	$	165,391.68	
REACTOR AUXILIARY BUILDING,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-200-224	6,021,480.87	$	4,064,499.59	0%	$	-	Not used.
REACTOR AUXILIARY BUILDING,CHEMICAL INJECTION SYSTEM 8150-200-438	25,023.59	$	16,890.92	0%	$	-	Not used.
REACTOR AUXILIARY BUILDING,CIRCULATING WATER SYSTEM 8150-200-435	38,284.20	$	25,841.84	0%	$	-	Not used.
REACTOR AUXILIARY BUILDING,CLEAN RADWASTE TREATMENT SYSTEM 8150-200-250	3,711,879.64	$	2,505,518.76	100%	$	2,505,518.76	
REACTOR AUXILIARY BUILDING,CLEAN RADWASTE TREATMENT SYSTEM 8150-200-610	17,128.05	$	11,561.43	100%	$	11,561.43	
REACTOR AUXILIARY BUILDING,COMPONENT COOLING WATER SYSTEM 8150-200-216	3,477,286.60	$	2,347,168.46	50%	$	1,173,584.23	In service to support the SFP Cooling sys.
REACTOR AUXILIARY BUILDING,CONDENSATE SYSTEM 8150-200-430	160,614.12	$	108,414.53	0%	$	-	Not used.
REACTOR AUXILIARY BUILDING,CONTAINMENT HEAT AND VENT SYSTEM 8150-200-228	69,258.79	$	46,749.68	100%	$	46,749.68	
REACTOR AUXILIARY BUILDING,CONTAINMENT SPRAY SYSTEM 8150-200-227	1,380,800.87	$	932,040.59	0%	$	-	Not used.
REACTOR AUXILIARY BUILDING,CRANES & HOISTS 8150-200-805	18,791.54	$	12,684.29	100%	$	12,684.29	
REACTOR AUXILIARY BUILDING,DEMINERALIZER SYSTEM 8150-200-243	533,385.96	$	360,035.52	15%	$	54,005.33	
REACTOR AUXILIARY BUILDING,DIESEL FUEL OIL SYSTEM 8150-200-626	193,288.09	$	130,469.46	0%	$	-	Not used.
REACTOR AUXILIARY BUILDING,DIRTY RADWASTE TREATMENT SYSTEM 8150-200-251	790,814.51	$	533,799.79	100%	$	533,799.79	
REACTOR AUXILIARY BUILDING,DOMESTIC WATER SYSTEM 8150-200-451	43,086.86	$	29,083.63	100%	$	29,083.63	
REACTOR AUXILIARY BUILDING,EXCAVATION 8150-200-006	360,920.16	$	243,621.11	100%	$	243,621.11	
REACTOR AUXILIARY BUILDING,EXTERIOR WALLS 8150-200-040	659,882.76	$	445,420.86	100%	$	445,420.86	
REACTOR AUXILIARY BUILDING,EXTRACTION STEAM SYSTEM 8150-200-423	101,640.26	$	68,607.18	0%	$	-	Not used.
REACTOR AUXILIARY BUILDING,FIRE PROTECTION EQUIPMENT 8150-200-130	2,178,870.97	$	1,470,737.90	100%	$	1,470,737.90	
REACTOR AUXILIARY BUILDING,FIXED AREA RADIATION MONITOR SYSTEM 8150-200-260	546,170.57	$	368,665.13	100%	$	368,665.13	
REACTOR AUXILIARY BUILDING,FLOORS AND FLOOR COVERINGS 8150-200-030	123,265.46	$	83,204.19	100%	$	83,204.19	
REACTOR AUXILIARY BUILDING,FOUNDATION AND BASE SLAB 8150-200-010	1,489,188.11	$	1,005,201.97	100%	$	1,005,201.97	
REACTOR AUXILIARY BUILDING,FUEL HANDLING AND STORAGE EQUIPMENT 8150-200-231	19,913.05	$	13,441.31	100%	$	13,441.31	
REACTOR AUXILIARY BUILDING,FURNITURE & OFFICE EQUIPMENT 8150-200-100	176.23	$	118.96	100%	$	118.96	
REACTOR AUXILIARY BUILDING,GASEOUS RADWASTE TREATMENT SYSTEM 8150-200-252	2,876,838.76	$	1,941,866.16	0%	$	-	Not used.

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
REACTOR AUXILIARY BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-200-120	2,061,078.12	$ 1,391,227.73	100%	$ 1,391,227.73	
REACTOR AUXILIARY BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-200-425	388,378.33	$ 262,155.37	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-200-810	1,512,385.02	$ 1,020,859.89	30%	$ 306,257.97	
REACTOR AUXILIARY BUILDING,INSTRUMENTS RACKS AND PANELS 8150-200-200	7,899.17	$ 5,331.94	30%	$ 1,599.58	
REACTOR AUXILIARY BUILDING,INSTRUMENTS RACKS AND PANELS 8150-200-256	6,185,985.29	$ 4,175,540.07	30%	$ 1,252,662.02	
REACTOR AUXILIARY BUILDING,INSTRUMENTS RACKS AND PANELS 8150-200-460	10,258.17	$ 6,924.26	30%	$ 2,077.28	
REACTOR AUXILIARY BUILDING,INTERIOR WALLS AND CEILINGS 8150-200-050	4,254,158.76	$ 2,871,557.16	100%	$ 2,871,557.16	
REACTOR AUXILIARY BUILDING,LAB EQUIPMENT 8150-200-134	82,364.17	$ 55,595.81	100%	$ 55,595.81	
REACTOR AUXILIARY BUILDING,LADDERS AND STAIRWAYS 8150-200-013	256,438.49	$ 173,095.98	100%	$ 173,095.98	
REACTOR AUXILIARY BUILDING,LIGHTING AND CONTROLS 8150-200-110	213,541.70	$ 144,140.65	100%	$ 144,140.65	
REACTOR AUXILIARY BUILDING,MAIN STEAM SYSTEM 8150-200-420	697,381.16	$ 470,732.28	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,MAKE-UP WATER TREATMENT SYSTEM 8150-200-446	73,518.56	$ 49,625.03	100%	$ 49,625.03	Used to support CCW and SFP
REACTOR AUXILIARY BUILDING,MISC GAS SUPPLY SYSTEM 8150-200-815	2,347,470.64	$ 1,584,542.68	50%	$ 792,271.34	Nitrogen sys. For CCW and SFP doors
REACTOR AUXILIARY BUILDING,NUCLEAR INSTRUMENTATION SYSTEM 8150-200-263	4,339.53	$ 2,929.18	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,PLUMBING 8150-200-090	1,055,521.51	$ 712,477.02	100%	$ 712,477.02	
REACTOR AUXILIARY BUILDING,POWER SYSTEMS 8150-200-265	136,035.40	$ 91,823.90	100%	$ 91,823.90	
REACTOR AUXILIARY BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-200-225	463,660.63	$ 312,970.93	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-200-245	293,661.33	$ 198,221.40	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-200-262	3,648,439.86	$ 2,462,696.91	100%	$ 2,462,696.91	
REACTOR AUXILIARY BUILDING,PROCESS SAMPLING SYSTEM 8150-200-267	2,017,661.33	$ 1,361,921.40	30%	$ 408,576.42	
REACTOR AUXILIARY BUILDING,PROCESS SAMPLING SYSTEM 8150-200-670	4,443.27	$ 2,999.21	30%	$ 899.76	
REACTOR AUXILIARY BUILDING,PROCESS STEAM SYSTEM 8150-200-422	721,121.51	$ 486,757.02	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,REACTOR AUXILIARY HEAT AND VENT SYSTEM 8150-200-230	70,428.34	$ 47,539.13	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,REACTOR COOLANT SYSTEM 8150-200-221	1,044,521.59	$ 705,052.07	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,RESIDUAL HEAT REMOVAL SYSTEM 8150-200-215	3,396,554.62	$ 2,292,674.37	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-200-060	148,823.66	$ 100,455.97	100%	$ 100,455.97	
REACTOR AUXILIARY BUILDING,SAFETY INJECTION SYSTEM 8150-200-214	3,795,390.06	$ 2,561,888.29	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,SERVICE WATER SYSTEM 8150-200-440	3,258,322.92	$ 2,199,367.97	30%	$ 659,810.39	
REACTOR AUXILIARY BUILDING,SOLID RADWASTE TREATMENT SYSTEM 8150-200-253	221,984.66	$ 149,839.65	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,SPENT FUEL POOL COOLING SYSTEM 8150-200-233	1,587,028.72	$ 1,071,244.39	100%	$ 1,071,244.39	
REACTOR AUXILIARY BUILDING,STEAM GENERATOR BLOWDOWN SYSTEM 8150-200-254	1,036,420.47	$ 699,583.82	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,STRUCTURAL MATERIAL 8150-200-008	489,342.66	$ 330,306.30	100%	$ 330,306.30	
REACTOR AUXILIARY BUILDING,TOOLS AND EQUIPMENT 8150-200-136	88,663.17	$ 59,847.64	100%	$ 59,847.64	
REACTOR CONTAINMENT,120-V AC INSTRUMENT SYSTEM 8150-160-630	35,446.92	$ 23,926.67	100%	$ 23,926.67	
REACTOR CONTAINMENT,480-V AUXILIARY SYSTEM 8150-160-618	54,860.05	$ 37,030.53	100%	$ 37,030.53	
REACTOR CONTAINMENT,CARD KEY ACCESS SYSTEM 8150-160-911	16,510.41	$ 11,144.53	100%	$ 11,144.53	
REACTOR CONTAINMENT,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-160-224	2,315,521.21	$ 1,562,976.82	0%	$ -	
REACTOR CONTAINMENT,CLEAN RADWASTE TREATMENT SYSTEM 8150-160-250	616,810.03	$ 416,346.77	0%	$ -	
REACTOR CONTAINMENT,COMPONENT COOLING WATER SYSTEM 8150-160-216	5,678,663.94	$ 3,833,098.16	0%	$ -	
REACTOR CONTAINMENT,CONTAINMENT FLOORS AND WALKWAYS 8150-160-030	1,658,666.92	$ 1,119,600.17	100%	$ 1,119,600.17	
REACTOR CONTAINMENT,CONTAINMENT HEAT AND VENT SYSTEM 8150-160-228	1,247,793.63	$ 842,260.70	100%	$ 842,260.70	
REACTOR CONTAINMENT,CONTAINMENT PENETRATIONS 8150-160-229	1,395,881.38	$ 942,219.93	100%	$ 942,219.93	
REACTOR CONTAINMENT,CONTAINMENT SPRAY SYSTEM 8150-160-227	3,280,319.80	$ 2,214,215.87	0%	$ -	
REACTOR CONTAINMENT,CONTAINMENT SUPERSTRUCTURE 8150-160-020	13,627,370.32	$ 9,198,474.97	100%	$ 9,198,474.97	
REACTOR CONTAINMENT,CRANES & HOISTS 8150-160-805	1,600,664.35	$ 1,080,448.44	100%	$ 1,080,448.44	
REACTOR CONTAINMENT,DEMINERALIZER SYSTEM 8150-160-243	22,847.57	$ 15,422.11	0%	$ -	
REACTOR CONTAINMENT,DIRTY RADWASTE TREATMENT SYSTEM 8150-160-251	371,326.64	$ 250,645.48	100%	$ 250,645.48	Containment drains still inservice
REACTOR CONTAINMENT,ELECTRICAL PENETRATIONS 8150-160-010	4,733,329.29	$ 3,194,997.27	100%	$ 3,194,997.27	
REACTOR CONTAINMENT,EXCAVATION 8150-160-006	97,918.85	$ 66,095.22	100%	$ 66,095.22	
REACTOR CONTAINMENT,FEEDWATER SYSTEM 8150-160-431	1,386,793.98	$ 936,085.94	0%	$ -	
REACTOR CONTAINMENT,FIRE PROTECTION EQUIPMENT 8150-160-130	367,151.57	$ 247,827.31	100%	$ 247,827.31	
REACTOR CONTAINMENT,FIXED AREA RADIATION MONITOR SYSTEM 8150-160-260	9,861.89	$ 6,656.78	0%	$ -	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
REACTOR CONTAINMENT,FUEL HANDLING AND STORAGE EQUIPMENT 8150-160-231	188,547.49	$	127,269.56	0%	$	-	The fuel was removed from the containment bldg.
REACTOR CONTAINMENT,GASEOUS RADWASTE TREATMENT SYSTEM 8150-160-252	612,780.55	$	413,626.87	0%	$	-	
REACTOR CONTAINMENT,HEAT VENTILATING AND AIR CONDITIONING 8150-160-120	5,329,118.03	$	3,597,154.67	100%	$	3,597,154.67	
REACTOR CONTAINMENT,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-160-425	89,979.97	$	60,736.48	100%	$	60,736.48	
REACTOR CONTAINMENT,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-160-125	17,432.93	$	11,767.23	100%	$	11,767.23	
REACTOR CONTAINMENT,INSTRUMENT & SERVICE AIR SYSTEM 8150-160-810	1,285,957.27	$	868,021.16	100%	$	868,021.16	System in service to support decom. Act.
REACTOR CONTAINMENT,INSTRUMENTATION AND CONTROL 8150-160-261	3,117,089.79	$	2,104,035.61	0%	$	-	
REACTOR CONTAINMENT,INSTRUMENTS RACKS AND PANELS 8150-160-256	969,403.80	$	654,347.57	0%	$	-	
REACTOR CONTAINMENT,INSTRUMENTS RACKS AND PANELS 8150-160-460	13,588.94	$	9,172.53	0%	$	-	
REACTOR CONTAINMENT,INTEGRATED LEAK RATE TESTING SYSTEM 8150-160-257	21,581.55	$	14,567.55	0%	$	-	
REACTOR CONTAINMENT,INTERIOR WALLS AND DOME 8150-160-035	388,126.19	$	261,985.18	100%	$	261,985.18	
REACTOR CONTAINMENT,LAB EQUIPMENT 8150-160-134	65,153.95	$	43,978.92	0%	$	-	
REACTOR CONTAINMENT,LADDERS AND STAIRWAYS 8150-160-013	637,458.42	$	430,284.43	100%	$	430,284.43	
REACTOR CONTAINMENT,LIGHTING AND CONTROL 8150-160-110	471,626.97	$	318,348.20	100%	$	318,348.20	
REACTOR CONTAINMENT,MAIN STEAM SYSTEM 8150-160-420	4,360,259.63	$	2,943,175.25	0%	$	-	
REACTOR CONTAINMENT,MAKE-UP WATER TREATMENT SYSTEM 8150-160-446	169,988.66	$	114,742.35	100%	$	114,742.35	Still in service to support decom. Act.
REACTOR CONTAINMENT,MISC GAS SUPPLY SYSTEM 8150-160-815	89,710.72	$	60,554.74	0%	$	-	
REACTOR CONTAINMENT,MISCELLANEOUS REACTOR PLANT INSTRUMENT EQUIPMENT 8150-160-269	45,096.35	$	30,440.04	0%	$	-	
REACTOR CONTAINMENT,NUCLEAR INSTRUMENTATION SYSTEM 8150-160-263	4,243,271.09	$	2,864,207.99	0%	$	-	
REACTOR CONTAINMENT,PLUMBING 8150-160-090	13,475.57	$	9,096.01	0%	$	-	
REACTOR CONTAINMENT,PRIMARY MAKE-UP WATER SYSTEM 8150-160-225	114,796.42	$	77,487.58	0%	$	-	
REACTOR CONTAINMENT,PRIMARY MAKE-UP WATER SYSTEM 8150-160-245	52,040.46	$	35,127.31	0%	$	-	
REACTOR CONTAINMENT,PROCESS RADIATION MONITOR SYSTEM 8150-160-262	1,245,205.10	$	840,513.44	50%	$	420,256.72	PERM-1 for effluent monitoring
REACTOR CONTAINMENT,PROCESS SAMPLING SYSTEM 8150-160-267	1,453,061.34	$	980,816.40	0%	$	-	
REACTOR CONTAINMENT,REACTOR CONTROL AND PROTECTION SYSTEM 8150-160-264	84,618.18	$	57,117.27	0%	$	-	
REACTOR CONTAINMENT,REACTOR CONTROLS 8150-160-212	5,779,344.57	$	3,901,057.58	0%	$	-	
REACTOR CONTAINMENT,REACTOR COOLANT SYSTEM 8150-160-221	22,733,053.44	$	15,344,811.07	0%	$	-	
REACTOR CONTAINMENT,RESIDUAL HEAT REMOVAL SYSTEM 8150-160-215	2,485,200.92	$	1,677,510.62	0%	$	-	
REACTOR CONTAINMENT,ROOFS GUTTERS DOWNSPOUTS 8150-160-060	22,053.59	$	14,886.17	100%	$	14,886.17	
REACTOR CONTAINMENT,SAFETY INJECTION SYSTEM 8150-160-214	4,842,038.91	$	3,268,376.26	0%	$	-	
REACTOR CONTAINMENT,SERVICE WATER SYSTEM 8150-160-440	360.21	$	243.14	0%	$	-	
REACTOR CONTAINMENT,SPENT FUEL POOL COOLING SYSTEM 8150-160-233	289,019.40	$	195,088.10	0%	$	-	
REACTOR CONTAINMENT,STEAM GENERATOR BLOWDOWN SYSTEM 8150-160-254	1,534,601.30	$	1,035,855.88	0%	$	-	
REACTOR CONTAINMENT,STORES EQUIPMENT 8150-160-138	195.49	$	131.96	0%	$	-	
REACTOR CONTAINMENT,STRUCTURAL MATERIAL 8150-160-008	1,133,830.86	$	765,335.83	100%	$	765,335.83	
REACTOR CONTAINMENT,TOOLS & EQUIPMENT 8150-160-136	557,267.59	$	376,155.62	25%	$	94,038.91	Some tools, equipment and fixtires were needed for decommissioning the Reactor Vessel and other components.
REACTOR CONTAINMENT,TOOLS EQUIPMENT AND FIXTURES 8150-160-232	1,425,580.09	$	962,266.56	25%	$	240,566.64	
REACTOR CONTAINMENT,TRANSPORTATION-AUXILIARY COMPONENTS 8150-160-296	1,078,085.56	$	727,707.75	0%	$	-	
REACTOR CONTAINMENT,UNDISTRIBUTED PROPERTY CHARGE 8150-160-001	2,992,178.90	$	2,019,720.76	0%	$	-	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),BUILDING FRAME 8150-435-020	35,846.58	$	24,196.44	100%	$	24,196.44	This area was used to during the asset recovery process, store hazardous non-radioactive material and was later used to process and ship slightly contaminated concrete.
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),CABINETS SHELVES AND COUNTERS 8150-435-140	10,473.37	$	7,069.52	0%	$	-	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),ELECTRICAL SYSTEM 8150-435-100	5,101.25	$	3,443.34	100%	$	3,443.34	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),FENCING 8150-435-175	4,395.06	$	2,966.67	100%	$	2,966.67	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),FLOOR AND FLOOR COVERINGS 8150-435-030	4,503.26	$	3,039.70	100%	$	3,039.70	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),INTERIOR WALLS AND CEILINGS 8150-435-050	10,602.74	$	7,156.85	0%	$	-	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),LIGHTING AND CONTROLS 8150-435-110	943.48	$	636.85	100%	$	636.85	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),MISCELLANEOUS BUILDING EQUIPMENT 8150-435-199	50,432.00	$	34,041.60	100%	$	34,041.60	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),PLUMBING 8150-435-090	35,395.81	$	23,892.17	100%	$	23,892.17	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),ROADWAYS AND PARKING 8150-435-031	86,922.83	$	58,672.91	100%	$	58,672.91	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),STOREROOM EQUIPMENT 8150-435-138	12,191.10	$	8,228.99	100%	$	8,228.99	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),TEMPORARY STORAGE OF CHEMICAL WASTE 8150-435-180	44,011.17	$	29,707.54	100%	$	29,707.54	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),TOOLS & EQUIPMENT 8150-435-136	9,935.31	$	6,706.33	100%	$	6,706.33	
RECONCILIATION ADJUSTMENT,ADJUSTMENTS 8150-018-013	(60,662.37)	$	(40,947.10)	100%	$	(40,947.10)	
RECREATION FACILITIES,FURNITURE & OFFICE EQUIPMENT 8150-060-610	13,141.56	$	8,870.55	0%	$	-	The recreation area was used, but it was for the enjoyment of the public rather than the safety of the public.
RECREATION FACILITIES,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-060-125	1,340.26	$	904.68	100%	$	904.68	
RECREATION FACILITIES,MAINTENANCE BUILDING 8150-060-280	185,725.96	$	125,365.02	100%	$	125,365.02	
RECREATION FACILITIES,MODELS DISPLAYS & FILMS 8150-060-600	28,943.64	$	19,536.96	0%	$	-	VIC shutdown
RECREATION FACILITIES,OUTSIDE FACILITIES 8150-060-006	1,250.98	$	844.41	100%	$	844.41	
RECREATION FACILITIES,PICNIC SHELTER 1 8150-060-260	117,155.02	$	79,079.64	100%	$	79,079.64	
RECREATION FACILITIES,PICNIC SHELTER 2 8150-060-262	117,155.06	$	79,079.67	100%	$	79,079.67	
RECREATION FACILITIES,RECREATION AND PICNIC AREAS 8150-060-200	1,709,599.89	$	1,153,979.93	100%	$	1,153,979.93	
RECREATION FACILITIES,RECREATION AREA EQUIPMENT 8150-060-700	1,784.67	$	1,204.65	100%	$	1,204.65	
RECREATION FACILITIES,RECREATION AREA OFFICE BUILDING 8150-060-210	31,582.40	$	21,318.12	100%	$	21,318.12	
RECREATION FACILITIES,REFLECTING LAKE 8150-060-010	304,285.82	$	205,392.93	100%	$	205,392.93	
RECREATION FACILITIES,RESTROOM 1 8150-060-250	75,994.17	$	51,296.06	100%	$	51,296.06	
RECREATION FACILITIES,RESTROOM 2 8150-060-252	75,994.15	$	51,296.05	100%	$	51,296.05	
RECREATION FACILITIES,SECURITY EQUIPMENT 8150-060-123	1,889.78	$	1,275.60	100%	$	1,275.60	security-related
RECREATION FACILITIES,TOOLS & EQUIPMENT 8150-060-136	25,847.85	$	17,447.30	100%	$	17,447.30	
RECREATION FACILITIES,TRAFFIC CONTROL BOOTH 8150-060-270	29,157.30	$	19,681.18	0%	$	-	Building not used
RECREATION FACILITIES,WILDLIFE VIEWING SHELTER 8150-060-290	146,499.40	$	98,887.10	0%	$	-	
SECURITY BUILDING-WEST,BUILDING COMMUNICATIONS WIRING/EQUIP 8150-075-130	3,194.55	$	2,156.32	100%	$	2,156.32	
SECURITY BUILDING-WEST,BUILDING ELECTRICAL 8150-075-100	221,432.87	$	149,467.19	100%	$	149,467.19	
SECURITY BUILDING-WEST,BUILDING FRAME 8150-075-020	84,656.72	$	57,143.29	100%	$	57,143.29	Protect the public from security-related threats.
SECURITY BUILDING-WEST,BUILDING LIGHTING 8150-075-110	50,126.76	$	33,835.56	100%	$	33,835.56	
SECURITY BUILDING-WEST,BUILDING PLUMBING 8150-075-090	68,795.48	$	46,436.95	100%	$	46,436.95	
SECURITY BUILDING-WEST,CABINETS, SHELVES & COUNTERS 8150-075-140	2,652.17	$	1,790.21	100%	$	1,790.21	
SECURITY BUILDING-WEST,EXTERIOR WALLS 8150-075-040	236,680.44	$	159,759.30	100%	$	159,759.30	
SECURITY BUILDING-WEST,FLOOR & FLOOR COVERINGS 8150-075-030	125,608.01	$	84,785.41	100%	$	84,785.41	
SECURITY BUILDING-WEST,FOUNDATION & BASE SLAB 8150-075-010	127,141.45	$	85,820.48	100%	$	85,820.48	
SECURITY BUILDING-WEST,HEAT, VENTILATING & AIR CONDITIONING 8150-075-120	129,588.79	$	87,472.43	100%	$	87,472.43	
SECURITY BUILDING-WEST,INTERIOR WALLS & CEILINGS 8150-075-050	277,070.60	$	187,022.66	100%	$	187,022.66	
SECURITY BUILDING-WEST,LABRATORY EQUIPMENT 8150-075-500	261,726.02	$	176,665.06	100%	$	176,665.06	
SECURITY BUILDING-WEST,ROOFING, GUTTERS, & DOWNSPOUTS 8150-075-060	75,675.03	$	51,080.65	100%	$	51,080.65	
SECURITY BUILDING-WEST,SECURITY EQUIPMENT 8150-075-123	907,256.85	$	612,398.37	100%	$	612,398.37	
SECURITY BUILDING-WEST,TEMPORARY FENCING & SECURITY EQUIPMENT 8150-075-001	11,775.55	$	7,948.50	100%	$	7,948.50	
SIMULATOR TRAINING FACILITY,BUILDING FRAME 8150-115-020	729,261.13	$	492,251.26	100%	$	492,251.26	
SIMULATOR TRAINING FACILITY,CABINETS, SHELVES AND COUNTERS 8150-115-140	91,286.27	$	61,618.23	5%	$	3,080.91	The training Bldg was used later on for training during decommissioning, LCR project, to support large plant meetings, and the ISFSI project (in particular for welder training.
SIMULATOR TRAINING FACILITY,CABLE TRAYS 8150-115-011	92,589.76	$	62,498.09	100%	$	62,498.09	
SIMULATOR TRAINING FACILITY,COMMUNICATION EQUIPMENT 8150-115-010	295,428.57	$	199,414.28	100%	$	199,414.28	
SIMULATOR TRAINING FACILITY,COMMUNICATION EQUIPMENT-INTERSITE ONLY. 8150-115-125	27,569.17	$	18,609.19	100%	$	18,609.19	
SIMULATOR TRAINING FACILITY,COMPUTER EQUIPMENT-(TO CLOSE 89--ITMS S/B TRNSFRD) 8150-115-645	192,040.14	$	129,627.09	0%	$	-	
SIMULATOR TRAINING FACILITY,ELEVATORS 8150-115-144	53,835.15	$	36,338.73	100%	$	36,338.73	
SIMULATOR TRAINING FACILITY,EXTERIOR WALLS 8150-115-040	809,560.04	$	546,453.03	100%	$	546,453.03	
SIMULATOR TRAINING FACILITY,FIRE PROTECTION EQUIPMENT 8150-115-130	338,613.27	$	228,563.96	100%	$	228,563.96	
SIMULATOR TRAINING FACILITY,FLOORS AND FLOOR COVERINGS 8150-115-030	467,592.14	$	315,624.69	5%	$	15,781.23	
SIMULATOR TRAINING FACILITY,FURNITURE AND OFFICE EQUIPMENT 8150-115-100	1,150,500.43	$	776,587.79	5%	$	38,829.39	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
SIMULATOR TRAINING FACILITY,HEATING, VENTILATING & AIR CONDITIONING 8150-115-120	1,208,642.92 $	815,833.97	100% $	815,833.97	
SIMULATOR TRAINING FACILITY,HOISTS AND CRANES 8150-115-805	47,311.71 $	31,935.40	100% $	31,935.40	
SIMULATOR TRAINING FACILITY,INSTRU;MENTS RACKS AND PANELS 8150-115-460	152,390.98 $	102,863.91	5% $	5,143.20	
SIMULATOR TRAINING FACILITY,INTERIOR WALLS AND CEILINGS 8150-115-050	679,955.30 $	458,969.83	100% $	458,969.83	
SIMULATOR TRAINING FACILITY,LABORATORY EQUIPMENT 8150-115-500	364,162.05 $	245,809.38	5% $	12,290.47	
SIMULATOR TRAINING FACILITY,MAINTENANCE BUILDING 8150-115-280	11,964.35 $	8,075.94	5% $	403.80	
SIMULATOR TRAINING FACILITY,ROADS, ROADWAYS, AND PARKING LOTS 8150-115-035	195,810.00 $	132,171.75	100% $	132,171.75	
SIMULATOR TRAINING FACILITY,ROOFING, GUTTERS, DOWNSPOUTS 8150-115-060	348,856.53 $	235,478.16	100% $	235,478.16	
SIMULATOR TRAINING FACILITY,SECURITY EQUIPMENT 8150-115-123	41,122.88 $	27,757.94	100% $	27,757.94	
SIMULATOR TRAINING FACILITY,TOOLS AND EQUIPMENT 8150-115-136	783.75 $	529.03	5% $	26.45	
SPARE PARTS,120-V AC INSTRUMENT SYSTEM 8150-600-630	17,094.85 $	11,539.02	100% $	11,539.02	Some spare parts were needed for maintenance, decommissioning and the ISFSI project.
SPARE PARTS,480-V SWITCHGEAR 8150-600-618	521.12 $	351.76	100% $	351.76	
SPARE PARTS,COMMUNICATION EQUIPMENT 8150-600-010	1,910.82 $	1,289.80	100% $	1,289.80	
SPARE PARTS,FIRE PROTECTION EQUIPMENT 8150-600-130	1,455.34 $	982.35	100% $	982.35	
SPARE PARTS,LAB EQUIPMENT 8150-600-134	967.79 $	653.26	100% $	653.26	
SPARE PARTS,MAIN CONTROL & ELECTRIC BOARD 8150-600-640	49,916.92 $	33,693.92	30% $	10,108.18	
SPARE PARTS,REACTOR CONTROLS 8150-600-212	9,967.13 $	6,727.81	0% $	-	
SPARE PARTS,REACTOR COOLANT SYSTEM 8150-600-221	14,620.57 $	9,868.88	0% $	-	
SPARE PARTS,SECURITY EQUIPMENT 8150-600-120	9,102.62 $	6,144.27	100% $	6,144.27	
SPARE PARTS,SNUBBERS 8150-600-063	163,242.69 $	110,188.82	0% $	-	
STEAM GENERATOR BLOWDOWN BUILDING,BUILDING FRAME 8150-430-020	170,715.21 $	115,232.77	100% $	115,232.77	Building contained radioactive contaminated material
STEAM GENERATOR BLOWDOWN BUILDING,ELECTRICAL SYSTEM 8150-430-100	910,654.12 $	614,691.53	0% $	-	
STEAM GENERATOR BLOWDOWN BUILDING,FENCING 8150-430-175	6,015.37 $	4,060.37	0% $	-	
STEAM GENERATOR BLOWDOWN BUILDING,FOUNDATION 8150-430-010	64,122.32 $	43,282.57	100% $	43,282.57	
STEAM GENERATOR BLOWDOWN BUILDING,HEAT VENTILATION AND AIR CONDITIONING 8150-430-120	20,729.47 $	13,992.39	0% $	-	
STEAM GENERATOR BLOWDOWN BUILDING,IN-PLANT COMMUNICATIONS EQUIP. 8150-430-125	1,651.93 $	1,115.05	0% $	-	
STEAM GENERATOR BLOWDOWN BUILDING,LIGHTING AND CONTROLS 8150-430-110	48,215.80 $	32,545.67	0% $	-	
STEAM GENERATOR BLOWDOWN BUILDING,STEAM GENERATOR BLOWDOWN SYSTEM 8150-430-254	5,392,160.63 $	3,639,708.43	0% $	-	
STEAM GENERATOR BLOWDOWN BUILDING,TOOLS AND EQUIPMENT 8150-430-136	25,304.51 $	17,080.54	0% $	-	
SULFURIC ACID STORAGE TANK BUILDING,CIRCULATING WATER SYSTEM 8150-370-435	316,095.28 $	213,364.31	0% $	-	Not used.
SULFURIC ACID STORAGE TANK BUILDING,DOMESTIC WATER SYSTEM 8150-370-451	11,470.39 $	7,742.51	0% $	-	
SULFURIC ACID STORAGE TANK BUILDING,ELECTICAL SYSTEM 8150-370-100	2,581.74 $	1,742.67	0% $	-	
SULFURIC ACID STORAGE TANK BUILDING,LIGHTING 8150-370-110	10,200.91 $	6,885.61	0% $	-	
SULFURIC ACID STORAGE TANK BUILDING,ROADWAYS AND PARKING 8150-370-030	31,962.13 $	21,574.44	0% $	-	
SWITCHYARD,230-KV ALLSTON BPA #1 LINE 8150-120-154	55,337.33 $	37,352.70	100% $	37,352.70	The Switchyard was necessary for power supply to the plant, and continues to be the interface between PGE and BPA at Alston.
SWITCHYARD,230-KV ALLSTON BPA #2 LINE 8150-120-156	96,604.85 $	65,208.27	100% $	65,208.27	
SWITCHYARD,230-KV BUS TIE V-81-82 8150-120-111	68,203.08 $	46,037.08	100% $	46,037.08	
SWITCHYARD,230-KV BUS TIE V-81-85 8150-120-113	22,889.86 $	15,450.66	100% $	15,450.66	
SWITCHYARD,230-KV BUS TIE V-82-85 8150-120-114	111,162.07 $	75,034.40	100% $	75,034.40	
SWITCHYARD,230-KV BUS V-81 8150-120-110	169,678.12 $	114,532.73	100% $	114,532.73	
SWITCHYARD,230-KV BUS V-82 8150-120-112	102,433.31 $	69,142.48	100% $	69,142.48	
SWITCHYARD,230-KV DEAD-END TOWER 8150-120-080	530,791.03 $	358,283.95	100% $	358,283.95	
SWITCHYARD,230-KV RIVERGATE LINE 8150-120-150	26,647.12 $	17,986.81	100% $	17,986.81	
SWITCHYARD,230-KV ST MARYS LINE 8150-120-152	55,272.25 $	37,308.77	100% $	37,308.77	
SWITCHYARD,A-C STATION SERVICE 8150-120-300	26,734.41 $	18,045.73	100% $	18,045.73	
SWITCHYARD,BUILDING FOUNDATION AND FLOORS 8150-120-020	81,876.05 $	55,266.33	100% $	55,266.33	
SWITCHYARD,COMMUNICATION EQUIPMENT 8150-120-010	512,665.83 $	346,049.44	100% $	346,049.44	
SWITCHYARD,CONDUIT & COPE TRAY 8150-120-220	1,928.60 $	1,301.81	100% $	1,301.81	
SWITCHYARD,CONTROL HOUSE BUILDING 8150-120-070	111,048.26 $	74,957.58	100% $	74,957.58	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
SWITCHYARD,CRUSHED ROCK SURFACING 8150-120-012	73,016.04	$	49,285.83	100%	$	49,285.83	
SWITCHYARD,DC POWER SUPPLY-MICROWAVE 8150-120-700	10,560.68	$	7,128.46	100%	$	7,128.46	
SWITCHYARD,D-C STATION SERVICE 8150-120-305	13,968.39	$	9,428.66	100%	$	9,428.66	
SWITCHYARD,FENCING 8150-120-175	17,376.73	$	11,729.29	100%	$	11,729.29	
SWITCHYARD,GROUND GRID 8150-120-670	36,414.49	$	24,579.78	100%	$	24,579.78	
SWITCHYARD,HEATING VENTILATING & AIR CONDITIONING 8150-120-120	230.76	$	155.76	100%	$	155.76	
SWITCHYARD,MAIN TRANSFORMER UNIT 1 8150-120-090	1,645,634.84	$	1,110,803.52	0%	$	-	Plant transformer not likely to be used.
SWITCHYARD,MICROWAVE PANEL EQUIPMENT 8150-120-100	25,298.24	$	17,076.31	100%	$	17,076.31	
SWITCHYARD,MISCELLANEOUS 8150-120-990	473,900.99	$	319,883.17	100%	$	319,883.17	
SWITCHYARD,OIL CIRCUIT BREAKERS 8150-120-401	559,296.31	$	377,525.01	100%	$	377,525.01	
SWITCHYARD,RELAY & SWITCH PANELS 8150-120-208	248,900.34	$	168,007.73	100%	$	168,007.73	
SWITCHYARD,START-UP TRANSFORMERS 8150-120-611	420,860.41	$	284,080.78	100%	$	284,080.78	Startup transformers still in service to supply the plant
SWITCHYARD,TELEMETERING EQUIPMENT 8150-120-209	145,786.13	$	98,405.64	100%	$	98,405.64	
SWITCHYARD,UNDERGROUND CONDUIT & DUCTS 8150-120-510	133,284.80	$	89,967.24	100%	$	89,967.24	
SWITCHYARD,VAULTS HANDHOLES & MANHOLES 8150-120-512	40,838.37	$	27,565.90	100%	$	27,565.90	
SWITCHYARD,YARD LOOP DISTRIBUTION SYSTEM 8150-120-490	630.72	$	425.74	100%	$	425.74	
SYSTEM CONTROL CENTER,COMMUNICATION EQUIPMENT 8150-450-010	33,407.54	$	22,550.09	100%	$	22,550.09	
TECHNICAL SUPPORT CENTER,CARD KEY ACCESS SYSTEM 8150-462-911	625,502.78	$	422,214.38	100%	$	422,214.38	The Technical Support Center housed some security equipment, records vault for NRC-required records, the contract labor force for decommissioning, and is now the ISFSI headquarters.
TECHNICAL SUPPORT CENTER,COMMUNICATIONS EQUIPMENT 8150-462-010	2,037,890.57	$	1,375,576.13	100%	$	1,375,576.13	
TECHNICAL SUPPORT CENTER,COMPUTER EQUIPMENT 8150-462-645	3,004,113.50	$	2,027,776.61	0%	$	-	Not used.
TECHNICAL SUPPORT CENTER,FIRE PROTECTION SYSTEM 8150-462-130	3,019.12	$	2,037.91	100%	$	2,037.91	
TECHNICAL SUPPORT CENTER,FIXED AREA RADIATION MONITOR SYSTEM 8150-462-260	193,697.65	$	130,745.91	0%	$	-	
TECHNICAL SUPPORT CENTER,FURNITURE AND OFFICE EQUIPMENT 8150-462-100	1,224,114.67	$	826,277.40	0%	$	-	
TECHNICAL SUPPORT CENTER,HEAT VENTILATING AND AIR CONDITIONING 8150-462-120	726,254.34	$	490,221.68	100%	$	490,221.68	
TECHNICAL SUPPORT CENTER,IN-PLANT COMMUNICATION EQUIP 8150-462-125	10,263.74	$	6,928.02	100%	$	6,928.02	
TECHNICAL SUPPORT CENTER,INTERIOR WALLS AND CEILINGS 8150-462-050	137,848.47	$	93,047.72	100%	$	93,047.72	
TECHNICAL SUPPORT CENTER,STRUCTURAL MATERIAL 8150-462-008	389,319.96	$	262,790.97	100%	$	262,790.97	
TRAILERS/MODULAR BUILDINGS,COMMUNICATION EQUIPMENT 8150-325-010	2,109.90	$	1,424.18	0%	$	-	
TURBINE-GENERATOR BUILDING,12.5-KV AUXILIARY SYSTEM 8150-240-616	364,269.24	$	245,881.74	100%	$	245,881.74	
TURBINE-GENERATOR BUILDING,4160-V AUXILIARY SYSTEM 8150-240-617	1,094,472.50	$	738,768.94	100%	$	738,768.94	Turbine Building contained electrical switchgear rooms, fire protection, plant air system compressors, and water systems. Structures also contained asbestos containing material and some equipment was potential contaminated until the Final Survey was completed
TURBINE-GENERATOR BUILDING,480-V AUXILIARY SYSTEM 8150-240-618	622,387.66	$	420,111.67	100%	$	420,111.67	
TURBINE-GENERATOR BUILDING,ALTERREX EXCITOR SYSTEM 8150-240-415	361,754.02	$	244,183.96	0%	$	-	
TURBINE-GENERATOR BUILDING,AUXILIARY FEEDWATER SYSTEM 8150-240-432	4,016,586.07	$	2,711,195.60	0%	$	-	
TURBINE-GENERATOR BUILDING,AUXILIARY STEAM SYSTEM 8150-240-421	970,257.41	$	654,923.75	0%	$	-	
TURBINE-GENERATOR BUILDING,BEARING COOLING WATER SYSTEM 8150-240-441	1,152,348.24	$	777,835.06	0%	$	-	
TURBINE-GENERATOR BUILDING,BUILDING FRAME 8150-240-020	5,643,620.08	$	3,809,443.55	100%	$	3,809,443.55	
TURBINE-GENERATOR BUILDING,CARD KEY ACCESS SYSTEM 8150-240-911	291,667.90	$	196,875.83	100%	$	196,875.83	
TURBINE-GENERATOR BUILDING,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-240-224	25,346.10	$	17,108.62	0%	$	-	
TURBINE-GENERATOR BUILDING,CHEMICAL INJECTION SYSTEM 8150-240-210	879,906.32	$	593,936.77	0%	$	-	
TURBINE-GENERATOR BUILDING,CHEMICAL INJECTION SYSTEM 8150-240-438	35,789.37	$	24,157.82	0%	$	-	
TURBINE-GENERATOR BUILDING,CIRCULATING WATER SYSTEM 8150-240-435	3,508,016.71	$	2,367,911.28	0%	$	-	
TURBINE-GENERATOR BUILDING,COMMUNICATIONS EQUIPMENT 8150-240-010	847,080.07	$	571,779.05	100%	$	571,779.05	
TURBINE-GENERATOR BUILDING,COMPONENT COOLING WATER SYSTEM 8150-240-216	190,836.56	$	128,814.68	0%	$	-	
TURBINE-GENERATOR BUILDING,CONDENSATE DEMINERALIZER SYSTEM 8150-240-434	161,936.93	$	109,307.43	0%	$	-	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
TURBINE-GENERATOR BUILDING,CONDENSATE SYSTEM 8150-240-430	21,366,478.04 $	14,422,372.68	0% $	-	
TURBINE-GENERATOR BUILDING,CRANES & HOISTS 8150-240-805	995,512.63 $	671,971.03	100% $	671,971.03	The Turbine Building was used later on for a laydown and quality assurance inspection area for spent fuel baskets during the ISFSI project.
TURBINE-GENERATOR BUILDING,DC ELECTRICAL SYSTEM 8150-240-620	66,135.14 $	44,641.22	100% $	44,641.22	
TURBINE-GENERATOR BUILDING,DECHLORINATION SYSTEM 8150-240-448	4,701.55 $	3,173.55	100% $	3,173.55	
TURBINE-GENERATOR BUILDING,DEMINERALIZER SYSTEM 8150-240-243	877,527.95 $	592,331.37	100% $	592,331.37	
TURBINE-GENERATOR BUILDING,DIESEL FUEL OIL SYSTEM 8150-240-626	859,986.67 $	580,491.00	0% $	-	
TURBINE-GENERATOR BUILDING,DOMESTIC WATER SYSTEM 8150-240-451	589,257.76 $	397,748.99	100% $	397,748.99	
TURBINE-GENERATOR BUILDING,ELEVATORS 8150-240-144	67,605.12 $	45,633.46	100% $	45,633.46	
TURBINE-GENERATOR BUILDING,EXCAVATION 8150-240-006	88,599.25 $	59,804.49	100% $	59,804.49	
TURBINE-GENERATOR BUILDING,EXTERIOR WALLS 8150-240-040	1,797,798.30 $	1,213,513.85	100% $	1,213,513.85	
TURBINE-GENERATOR BUILDING,EXTRACTION STEAM SYSTEM 8150-240-423	8,313,195.08 $	5,611,406.68	0% $	-	
TURBINE-GENERATOR BUILDING,FEEDWATER SYSTEM 8150-240-429	34,097.93 $	23,016.10	0% $	-	
TURBINE-GENERATOR BUILDING,FEEDWATER SYSTEM 8150-240-431	25,347,008.01 $	17,109,230.41	0% $	-	
TURBINE-GENERATOR BUILDING,FIRE PROTECTION EQUIPMENT 8150-240-130	3,937,140.41 $	2,657,569.78	100% $	2,657,569.78	
TURBINE-GENERATOR BUILDING,FLOORS AND FLOOR COVERINGS 8150-240-030	146,958.13 $	99,196.74	100% $	99,196.74	
TURBINE-GENERATOR BUILDING,FOUNDATIONS 8150-240-011	98,274.06 $	66,334.99	100% $	66,334.99	
TURBINE-GENERATOR BUILDING,GENERATOR EXCITER SYSTEM 8150-240-605	6,850.05 $	4,623.78	0% $	-	
TURBINE-GENERATOR BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-240-120	2,097,826.19 $	1,416,032.68	100% $	1,416,032.68	
TURBINE-GENERATOR BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-240-425	14,129,783.94 $	9,537,604.16	100% $	9,537,604.16	
TURBINE-GENERATOR BUILDING,HYDROGEN COOLING SYSTEM 8150-240-418	373,641.94 $	252,208.31	0% $	-	
TURBINE-GENERATOR BUILDING,HYDROGEN SYSTEM 8150-240-419	1,100,409.33 $	742,776.30	0% $	-	
TURBINE-GENERATOR BUILDING,IN-PLANT COMMUNICATION EQUIP 8150-240-125	1,023.67 $	690.98	100% $	690.98	
TURBINE-GENERATOR BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-240-810	2,540,298.47 $	1,714,701.47	100% $	1,714,701.47	The air compressors were located in the Turbine Building.
TURBINE-GENERATOR BUILDING,INSTRUMENTS RACKS & PANELS 8150-240-460	4,161,860.95 $	2,809,256.14	10% $	280,925.61	
TURBINE-GENERATOR BUILDING,INSTRUMENTS RACKS AND PANELS 8150-240-256	317,429.05 $	214,264.61	10% $	21,426.46	
TURBINE-GENERATOR BUILDING,INTERIOR WALLS AND CEILINGS 8150-240-050	443,253.25 $	299,195.94	100% $	299,195.94	
TURBINE-GENERATOR BUILDING,ISOLATED PHASE BUS 8150-240-200	111,236.50 $	75,084.64	0% $	-	
TURBINE-GENERATOR BUILDING,LADDERS AND STAIRWAYS 8150-240-013	243,697.15 $	164,495.58	100% $	164,495.58	
TURBINE-GENERATOR BUILDING,LIGHTING AND CONTROLS 8150-240-070	13,722.45 $	9,262.65	100% $	9,262.65	
TURBINE-GENERATOR BUILDING,LIGHTING AND CONTROLS 8150-240-110	869,489.73 $	586,905.57	100% $	586,905.57	
TURBINE-GENERATOR BUILDING,LUBE OIL STORAGE AND FILTER SYSTEM 8150-240-416	1,636,331.61 $	1,104,523.84	0% $	-	
TURBINE-GENERATOR BUILDING,MAIN CONTROL & ELECTRIC BOARD 8150-240-640	73.36 $	49.52	0% $	-	
TURBINE-GENERATOR BUILDING,MAIN STEAM SYSTEM 8150-240-420	5,965,489.47 $	4,026,705.39	0% $	-	
TURBINE-GENERATOR BUILDING,MAKE-UP WATER TREATMENT SYSTEM 8150-240-446	862,695.20 $	582,319.26	0% $	-	
TURBINE-GENERATOR BUILDING,MISC GAS SUPPLY SYSTEM 8150-240-815	1,523,475.19 $	1,028,345.75	0% $	-	
TURBINE-GENERATOR BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-240-245	173,306.11 $	116,981.62	0% $	-	
TURBINE-GENERATOR BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-240-262	1,682,860.02 $	1,135,930.51	0% $	-	
TURBINE-GENERATOR BUILDING,PROCESS SAMPLING SYSTEM 8150-240-267	1,046,878.84 $	706,643.22	0% $	-	
TURBINE-GENERATOR BUILDING,PROCESS STEAM SYSTEM 8150-240-422	484,719.85 $	327,185.90	0% $	-	
TURBINE-GENERATOR BUILDING,REACTOR COOLANT SYSTEM 8150-240-221	91,920.69 $	62,046.47	0% $	-	
TURBINE-GENERATOR BUILDING,REHEAT AND MOISTURE SEPARATOR SYSTEM 8150-240-428	723,199.33 $	488,159.55	0% $	-	
TURBINE-GENERATOR BUILDING,REHEAT AND MOISTURE SEPARATOR SYSTEM 8150-240-440	4,003,721.19 $	2,702,511.80	0% $	-	
TURBINE-GENERATOR BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-240-060	416,700.36 $	281,272.74	100% $	281,272.74	
TURBINE-GENERATOR BUILDING,SECURITY EQUIPMENT 8150-240-123	542.33 $	366.07	100% $	366.07	
TURBINE-GENERATOR BUILDING,STEAM GENERATOR BLOWDOWN SYSTEM 8150-240-254	14,120.46 $	9,531.31	0% $	-	
TURBINE-GENERATOR BUILDING,STEAM SEAL AND DRAIN SYSTEM 8150-240-426	256,694.33 $	173,268.67	0% $	-	
TURBINE-GENERATOR BUILDING,STORES EQUIPMENT 8150-240-138	390.98 $	263.91	0% $	-	
TURBINE-GENERATOR BUILDING,STRUCTURAL MATERIAL 8150-240-008	594,725.47 $	401,439.69	100% $	401,439.69	
TURBINE-GENERATOR BUILDING,TG CONTROL AND SUPPORT EQUIPMENT 8150-240-410	24,012.40 $	16,208.37	0% $	-	
TURBINE-GENERATOR BUILDING,TG ELECTRO-HYDRAULIC CONTROL SYSTEM 8150-240-411	1,645,453.01 $	1,110,680.78	0% $	-	
TURBINE-GENERATOR BUILDING,TOOLS & EQUIPMENT 8150-240-136	21,559.38 $	14,552.58	15% $	2,182.89	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
TURBINE-GENERATOR BUILDING,TURBINE GENERATOR STATOR 8150-240-417	5,379,618.23 $	3,631,242.31	0% $	-	
TURBINE-GENERATOR BUILDING,TURBINE GENERATOR SYSTEM 8150-240-409	39,661,707.24 $	26,771,652.39	0% $	-	
TURBINE-GENERATOR BUILDING,TURBINE GENERATOR TURNING GEAR 8150-240-413	484,297.89 $	326,901.08	0% $	-	
TURBINE-GENERATOR BUILDING,TURBINE-GENERATOR CONTROL PANEL 8150-240-407	1,009.61 $	681.49	0% $	-	
TURBINE-GENERATOR BUILDING,UNDISTRIBUTED PROPERTY CHARGE 8150-240-001	161,885.71 $	109,272.85	0% $	-	
TURBINE-GENERATOR BUILDING,WATER PIPING SYSTEM 8150-240-090	1,475,462.73 $	995,937.34	0% $	-	
UNDISTRIBUTED PROPERTY CHARGE,UNDISTRIBUTED PROPERTY CHARGE 8150-010-001	52.52 $	35.45	0% $	-	
UNDISTRIBUTED PROPERTY,FURNITURE WITH NO LOCATION 8150-015-100	761.84 $	514.24	0% $	-	
UNWORKED ACCOUNT 8150-001-001	3,249,519.37 $	2,193,425.57	0% $	-	
VEHICLES,VEHICLES, NO COMPANY NUMBER 8150-290-999	21,474.31 $	14,495.16	100% $	14,495.16	Maintenance used vehicles for transporting parts and tools to the worksite. Forklifts and mobile cranes were used for loading radwaste boxes and moving decommissioning and ISFSI equipment. Security used vehicles for patrols.
VEHICLES,VEHICLES, NUMBERS 006001 THRU 006999 8150-290-006	299,265.01 $	202,003.88	100% $	202,003.88	
VISITORS INFORMATION CENTER,BUILDING FRAME 8150-100-020	206,433.22 $	139,342.42	100% $	139,342.42	Visitors Information Center structure was needed because it housed asbestos-containing material.
VISITORS INFORMATION CENTER,COMMUNICATION EQUIPMENT 8150-100-010	136,906.89 $	92,412.15	0% $	-	
VISITORS INFORMATION CENTER,EMERGENCY OPERATING FACILITY 8150-100-131	664,159.32 $	448,307.54	0% $	-	
VISITORS INFORMATION CENTER,EXTERIOR WALLS 8150-100-040	213,043.85 $	143,804.60	100% $	143,804.60	
VISITORS INFORMATION CENTER,FENCING 8150-100-175	1,335.00 $	901.13	0% $	-	
VISITORS INFORMATION CENTER,FIRE PROTECTION SYSTEM 8150-100-130	11,565.89 $	7,806.98	100% $	7,806.98	
VISITORS INFORMATION CENTER,FLOORS & FLOOR COVERINGS 8150-100-030	101,891.39 $	68,776.69	0% $	-	
VISITORS INFORMATION CENTER,FOUNDATION & BASE SLAB 8150-100-012	107,606.10 $	72,634.12	100% $	72,634.12	
VISITORS INFORMATION CENTER,FURNITURE AND OFFICE EQUIPMENT 8150-100-100	108,792.21 $	73,434.74	0% $	-	
VISITORS INFORMATION CENTER,HEATING VENTILATING AND AIR CONDITIONING 8150-100-120	205,649.94 $	138,813.71	0% $	-	
VISITORS INFORMATION CENTER,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-100-125	473.62 $	319.69	0% $	-	
VISITORS INFORMATION CENTER,LAB EQUIPMENT 8150-100-134	15,974.99 $	10,783.12	0% $	-	
VISITORS INFORMATION CENTER,MISC EQUIPMENT 8150-100-612	16,128.05 $	10,886.43	0% $	-	
VISITORS INFORMATION CENTER,MISCELLANEOUS EQUIPMENT 8150-100-199	3,788.54 $	2,557.26	0% $	-	
VISITORS INFORMATION CENTER,OUTSIDE FACILITIES 8150-100-006	445,798.45 $	300,913.95	0% $	-	
VISITORS INFORMATION CENTER,PARTITIONS & CEILINGS 8150-100-005	46,983.77 $	31,714.04	0% $	-	
VISITORS INFORMATION CENTER,PARTITIONS AND CEILINGS 8150-100-050	231,320.34 $	156,141.23	0% $	-	
VISITORS INFORMATION CENTER,PLUMBING 8150-100-090	7,308.87 $	4,933.49	0% $	-	
VISITORS INFORMATION CENTER,PRELIMINARY COSTS 8150-100-004	228,625.53 $	154,322.23	0% $	-	
VISITORS INFORMATION CENTER,ROOFS GUTTERS AND DOWNSPOUTS 8150-100-060	87,930.81 $	59,353.30	100% $	59,353.30	
VISITORS INFORMATION CENTER,SECURITY EQUIPMENT 8150-100-123	7,735.46 $	5,221.44	0% $	-	
VISITORS INFORMATION CENTER,SOUND SYSTEMS 8150-100-102	13,113.18 $	8,851.40	0% $	-	
VISITORS INFORMATION CENTER,STAIRWAYS 8150-100-070	19,852.42 $	13,400.38	100% $	13,400.38	
VISITORS INFORMATION CENTER,YARD LOOP DISTRIBUTION SYSTEM 8150-100-490	493.31 $	332.98	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),BUILDING FRAME 8150-440-020	220,085.10 $	148,557.44	100% $	148,557.44	Maintenance building and shop.
WAREHOUSE AND SHOP (MATERIAL SERVICES),CABINETS SHELVES AND COUNTERS 8150-440-140	51,687.26 $	34,888.90	100% $	34,888.90	
WAREHOUSE AND SHOP (MATERIAL SERVICES),CARD KEY ACCESS SYSTEM 8150-440-911	68,903.80 $	46,510.07	100% $	46,510.07	
WAREHOUSE AND SHOP (MATERIAL SERVICES),COMMUNICATIONS EQUIPMENT 8150-440-010	328,393.51 $	221,665.62	100% $	221,665.62	
WAREHOUSE AND SHOP (MATERIAL SERVICES),COMPUTER EQUIPMENT 8150-440-645	1,834,575.74 $	1,238,338.62	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),COMPUTER EQUIPMENT-NOT NUMBERED 8150-440-647	381,900.44 $	257,782.80	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),CONSTRUCTION BUILDINGS 8150-440-178	282,794.14 $	190,886.04	100% $	190,886.04	
WAREHOUSE AND SHOP (MATERIAL SERVICES),CRANES & HOISTS 8150-440-805	72,571.15 $	48,985.53	100% $	48,985.53	
WAREHOUSE AND SHOP (MATERIAL SERVICES),EXCAVATION 8150-440-006	4,839.34 $	3,266.55	100% $	3,266.55	
WAREHOUSE AND SHOP (MATERIAL SERVICES),EXTERIOR WALLS 8150-440-040	279,318.05 $	188,539.68	100% $	188,539.68	
WAREHOUSE AND SHOP (MATERIAL SERVICES),FENCING 8150-440-175	96,046.74 $	64,831.55	100% $	64,831.55	
WAREHOUSE AND SHOP (MATERIAL SERVICES),FIRE PROTECTION EQUIPMENT 8150-440-130	169,415.24 $	114,355.29	100% $	114,355.29	
WAREHOUSE AND SHOP (MATERIAL SERVICES),FLOORS AND FLOOR COVERINGS 8150-440-030	107,820.12 $	72,778.58	100% $	72,778.58	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
WAREHOUSE AND SHOP (MATERIAL SERVICES),FURNITURE & OFFICE EQUIPMENT 8150-440-100	362,175.68	$	244,468.58	20%	$	48,893.72	
WAREHOUSE AND SHOP (MATERIAL SERVICES),HEAT VENTILATING AND AIR CONDITIONING 8150-440-120	287,312.39	$	193,935.86	100%	$	193,935.86	
WAREHOUSE AND SHOP (MATERIAL SERVICES),HOLDING FOR COMPUTER EQUIPMENT NUMBERS 8150-440-646	35,110.53	$	23,699.61	0%	$	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),INTERIOR WALLS AND CEILINGS 8150-440-050	50,934.97	$	34,381.10	100%	$	34,381.10	
WAREHOUSE AND SHOP (MATERIAL SERVICES),LAB EQUIPMENT 8150-440-134	5,658.35	$	3,819.39	0%	$	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),LIGHTING 8150-440-110	265,302.35	$	179,079.09	100%	$	179,079.09	
WAREHOUSE AND SHOP (MATERIAL SERVICES),MISC SPECIAL TOOLS 8150-440-910	22,648.39	$	15,287.66	100%	$	15,287.66	
WAREHOUSE AND SHOP (MATERIAL SERVICES),MISCELLANEOUS BUILDING EQUIPMENT 8150-440-199	115,542.90	$	77,991.46	100%	$	77,991.46	
WAREHOUSE AND SHOP (MATERIAL SERVICES),MODELS DISPLAYS & FILMS 8150-440-600	12,507.97	$	8,442.88	0%	$	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),PLUMBING 8150-440-090	62,844.35	$	42,419.94	100%	$	42,419.94	
WAREHOUSE AND SHOP (MATERIAL SERVICES),ROOFS GUTTERS DOWNSPOUTS 8150-440-060	48,801.68	$	32,941.13	100%	$	32,941.13	
WAREHOUSE AND SHOP (MATERIAL SERVICES),SECURITY EQUIPMENT 8150-440-123	207.64	$	140.16	100%	$	140.16	
WAREHOUSE AND SHOP (MATERIAL SERVICES),SPARE PARTS 8150-440-915	79,923.48	$	53,948.35	100%	$	53,948.35	
WAREHOUSE AND SHOP (MATERIAL SERVICES),STORES EQUIPMENT 8150-440-138	509,023.30	$	343,590.73	100%	$	343,590.73	
WAREHOUSE AND SHOP (MATERIAL SERVICES),STRUCTURAL MATERIAL 8150-440-008	58,096.31	$	39,215.01	100%	$	39,215.01	
WAREHOUSE AND SHOP (MATERIAL SERVICES),TOOLS & EQUIPMENT 8150-440-136	832,925.28	$	562,224.56	100%	$	562,224.56	
					$	-	
	670,820,435.56		452,803,794.00			214,488,944.77	

Gross Plant Cost Total	556,249,705
Accum Amort	(261,663,314)
Net Plant	294,586,391
Plant in Service Share of Gross	38.6%
Implied Share of Net Plant	113,592,014

I. Introduction

Q. Please state your name and position.

A. My name is Patrick G. Hager. My position is Manager, Regulatory Affairs. My current qualifications are at the end of this testimony.

Q. Have you previously provided testimony in this docket?

A. Yes. I have previously offered cost of capital testimony and sponsored three PGE Exhibits. First, I co-sponsored PGE's opening cost of capital testimony in UE 88 (PGE Exhibit 700). Second, I sponsored PGE's testimony that summarized and supported the cost of capital stipulation PGE reached with the OPUC Staff (PGE Exhibit 2600). Third, I provided testimony regarding the expected financial effects on PGE under different Trojan return alternatives (PGE Exhibit 2300).

Q. What is the purpose of your testimony?

A. The purpose of my current testimony is three-fold. First, I summarize PGE's cost of capital testimony in UE 88. PGE prepared and submitted cost of capital testimony in 1993 and 1994, estimating PGE's cost of capital for the 1995-1996 test period. Second, I provide a qualitative analysis of the cost of capital effects of the Oregon Court of Appeals interpretation precluding the Commission from permitting a return on plant that has been retired economically to achieve least cost for customers. I show that, had this interpretation of Oregon law been available at the time of UE 88, PGE would have supported a higher required return on equity as well as on debt to reflect the increased risk of Oregon's regulatory environment. Given the significant new information that the Commission cannot set rates based on allowing PGE a return on our undepreciated Trojan investment, I have modified my estimated range for PGE's Required Return on Equity (RROE). My range differs depending on whether the regulatory environment is one of simply “no return on but rapid recovery of” or “no return on and slow recovery of” such investments. If the Commission allows PGE to collect its unamortized investment in Trojan over a short period of time, then my estimated range for PGE’s RROE is 11.7% to 11.94%, with a point estimate of 11.85%. If the Commission specifies a longer period of time over which PGE can collect its investment, then my estimated range is 12.8% to 13.4%, with a point estimate of 13.1%. Third, I provide a brief overview of the remaining cost of capital witnesses. Their testimony supports my analysis and my estimate of the range for the higher required return.

II. PGE's UE 88 Cost of Capital Analysis

A. Overview

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:

$$k = r + \pi + i + b + f + l \quad \textbf{(1)}$$

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" <u>above</u> the nominal interest rate that the investor requires to purchase the common stock or investment. 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. Expected ROE refers to an investor's anticipated return on an investment security as part of a decision to purchase or sell the security. 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 for the potential return on equity that the company can earn. If the authorized return on equity is set "low," then investors will expect the company to earn a lower return on equity. Conversely, if the authorized return on equity is set "high," then investors will expect the company to earn a higher return on equity.

Q. What do you mean by PGE's Required Return on Equity (RROE)?

A. PGE's RROE is the ROE that investors require in order to buy or hold PGE's common equity. This is the appropriate rate for PGE, considering the pricing and operation risks proposed for PGE as discussed elsewhere in the UE 88 filing.

Q. Why is it important that PGE's authorized ROE be set at or above PGE's RROE?

A. It enables PGE to attract equity capital on favorable terms in the marketplace.

Q. Please explain.

A. 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 and expected returns on other (alternative) investments. Most sophisticated 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 <u>required</u> ROE for the selected stock, the investor then compares it to the <u>expected</u> ROE. As stated above, the expected return for a utility is dependent on the utility's authorized rate of return. 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. One consequence of this is that PGE would have to issue more shares than otherwise to raise the same amount of capital, increasing its dividend cost and hurting its financials.

To ensure its ability to attract common equity on favorable terms in the marketplace, PGE must provide current and prospective shareholders with an ROE that encompasses their range of required ROEs. The return I recommend accomplishes this goal and would have allowed PGE to attract capital on favorable terms in the marketplace, had the Commission adopted it in UE 88.

1. <u>The Discounted Cash Flow and Capital Asset Pricing Models</u>

Q. You stated that investors used one or more financial models to determine the required return on their investment. What financial models did you use in 1993 and 1994 to determine PGE's RROE?

A. I used the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM) models to calculate the range for PGE's RROE. I also considered authorized ROEs that had been recently granted in other state jurisdictions.

Q. Please briefly describe the CAPM model.

A. The Capital Asset Pricing Model (CAPM) focuses on the investor's portfolio and the risk associated with a particular portfolio. Specifically, CAPM assumes that the investor holds a market portfolio consisting of every financial asset in the world. It is from the investor's portfolio decisions that the risk and value of an individual firm can be determined and, thus, the Required Return on Equity (RROE) for the firm can also be found. The firm's relevant risk can be measured by a single number, Beta. The Required Rate of Return is then a simple function of Beta:

RROE = (Risk-free rate) + Beta times (Expected return on the market portfolio - Risk free rate) **(2)**

Q. What is Beta?

A. By definition, Beta is the regression coefficient of the company's common stock return or the covariance of the company's stock return with the market return divided by the variance of the market return. More intuitively, Beta can be thought of simply as the ratio of changes in the company's return to changes in the market's return.

Q. What is the Expected Return minus the Risk-free rate?

A. This term is called the Market Risk Premium. It is the return above the risk-free rate that an investor must receive in order to hold the market portfolio instead of the risk-free security.

Q. Is the CAPM a Risk Premium model?

A. Yes. Like other Risk Premium Models, CAPM attempts to estimate the premium over and above the risk-free rate that an investor requires in order to hold an investment instead of the risk-free security. Dr. Hess also describes the CAPM model in PGE Exhibit 6700.

Q. Please briefly describe the DCF model.

A. 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. The most common forms of the DCF model are single- and multi-stage.

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:

$$P_o = D_1 \div (k_e - g) \qquad \textbf{(3)}$$

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:

$$k_e = (D_1 \div P_0) + g \qquad \textbf{(4)}$$

This general form of the DCF model is known as a single-stage growth model because it assumes a constant dividend growth rate over time.

Q. What is the multi-stage DCF model?

A. The multi-stage DCF does not assume a constant dividend growth rate so that solving for the cost of equity is more complicated. Equations 3 and 4 above assume a single growth rate. If more than one dividend growth rate is assumed, then the equations become more complex:

$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \Lambda + \frac{D_n}{(1+k)^n} + \frac{P_n}{(1+k)^n} \qquad \textbf{(5)}$$

or

$$P_o = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \frac{P_n}{(1+k)^n} \qquad \textbf{(6)}$$

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 (6) above. Dr. Blaydon describes the DCF model in more detail in PGE Exhibit 6600.

2. <u>Opening cost of capital testimony</u>

Q. Please summarize PGE's opening cost of capital testimony in UE 88.

A. PGE filed its opening cost of capital testimony on November 8, 1993 (PGE Exhibit 700). We included financial information available through June 30, 1993 and stated that we planned to update our estimate with more current information in our rebuttal testimony. Our initial estimate for PGE's cost of capital for the test period 1995-1996 was:

Table 1
Opening Testimony RROE Estimates

Estimation Method	Range
Discounted Cash Flow	10.96% - 11.91%
CAPM	11.02% - 12.10%

3. Settlement (Rebuttal) cost of capital testimony.

Q. Did PGE file additional cost of capital testimony?

A. Yes. PGE reached a settlement with OPUC Staff concerning our 1995-1996 test period cost of capital. PGE filed testimony supporting the settlement in mid-November 1994, almost a year after our opening testimony.

Q. Please summarize this second round of testimony.

A. In our rebuttal testimony, we updated our estimate for PGE's cost of capital using financial information available through mid-November 1994. Our updated estimated range was:

Table 2
Updated RROE Estimates

Estimation Method	Range
Discounted Cash Flow	11.46% - 12.10%
CAPM	12.65% - 13.37%

The stipulated RROE was included in our updated estimated range for PGE's cost of capital.

Q. Why did your estimated RROE range increase from that in your opening testimony?

A. My direct testimony on PGE's cost of capital, filed in November 1993, was prepared using information available to investors as of June 30, 1993. The financial markets changed significantly between June 1993 and November 1994, not only with higher interest rates and stock market levels, but also demonstrating volatility during the period.

Q. How did the bond market behave during the June 1993 to November 1994 period?

A. The change and the associated volatility in the bond market can be illustrated using the "Treasury benchmark" 30-year bond, shown in PGE Exhibit 2603. Between June and mid-October 1993, the period just prior to our initial filing, interest rates, as measured by the 30-year Treasury Bond, <u>declined</u> by over 90 basis points, from 6.70% to 5.78%. However, interest rates then began to <u>rise</u>, reaching 7.55% in mid-August 1994, when Staff prepared its response testimony and rose further to 8.10% in early November 1994, at about the time of the cost of capital stipulation. As of November 21, 1994, the 30-year Treasury bond was at 8.13%, significantly higher than when we or Staff prepared our estimates.

Q. Describe how the stock market was higher and more volatile over this same time period?

A. The S&P 500 is frequently used as an index for the overall stock market. Figure 1 in PGE Exhibit 2604 shows the monthly average closing price for the Standard & Poor's 500 Index (S&P 500) from January 1993 through mid-November 1994. Figure 2 shows the daily high, low, and close for the period July 1, 1993 through November 10, 1994. Both graphs show that the S&P 500 rose from July 1993 through January 1994. Figure 2 shows that the daily volatility was significant at times. In mid-March 1994, the S&P 500 began a short but substantial decline, from approximately 470 to 441 in May, a 6% decline in less than two months. The S&P 500 fell below its July 1, 1993 level. Between May and November 1994, the S&P 500 climbed above 465, but its rise was punctuated with short and large declines. Given the changes in the financial market between May 1993 and November 1994 and the volatility, the higher and wider range for RROE is not unexpected.

Q. What effect did the higher interest rates, higher stock market, and the volatility have on PGE's required ROE?

A. The higher interest rates and stock market and volatility increased PGE's required ROE. My updated RROE estimates in Table 2 reflect this.

Q. Please describe the cost of capital settlement in UE 88.

A. PGE and the OPUC Staff reached a settlement in early November 1994 regarding PGE's authorized cost of capital, including its capital structure. Tables 3 and 4 below detail the settlement.

Table 3

Test Year 1995

	Capital Structure	Cost	Weighted Cost
a. Long-Term Debt	49.14%	7.71%	3.79%
b. Preferred Stock	5.42%	8.27%	0.45%
c. Common Equity	45.44%	11.60%	5.27%
	100.00%		
Rate of Return			9.51%

Table 4

Test Year 1996

	Capital Structure	Costs	Weighted Cost
a. Long-Term Debt	48.86%	7.82%	3.82%
b. Preferred Stock	4.67%	8.27%	0.39%
c. Common Equity	46.47%	11.60%	5.39%
	100.00%		
Rate of Return			9.60%

Q. Was the settlement within your updated estimated range for PGE's required ROE?

A. Yes. My updated estimated range for PGE's required ROE was 11.46% to 13.37%. The 11.60% settlement for PGE's authorized ROE was towards the bottom of the range, but acceptable to PGE as we expected full recovery of and on our investment in Trojan.

Q. Did the Commission accept the cost of capital settlement?

A. Yes. OPUC Order No. 95-322 adopted the cost of capital stipulation (OPUC Order No. 95-322, page 24 and Appendix E).

4. Effect of Trojan recovery alternatives on PGE's financial ratios

Q. Please briefly describe this testimony.

A. In November 1994, I provided testimony regarding four proposed Trojan recovery alternatives and their effects both upon PGE's ability to attract capital in the marketplace and PGE's cost of capital (PGE Exhibit 2300).

Q. Which four proposed Trojan recovery alternatives did you analyze?

A. I analyzed the three alternatives proposed by the OPUC Staff and CUB that would have had the largest financial impacts upon PGE. I compared these alternatives or scenarios to PGE's proposal, which was full recovery of and on the remaining Trojan investment. The four scenarios were:

1. PGE Proposal (100% recovery, full return, full amortization);
2. OPUC Staff Alternative 4 (0% recovery, no return, no amortization);
3. OPUC Staff Alternative 3 (100% recovery, no return, full amortization of remaining investment); and
4. CUB Alternative 1 (29% Recovery, no return, full amortization of remaining investment).

Q. What did your analysis show regarding these four alternatives?

A. My analysis showed that under any of the three proposed disallowance scenarios, PGE's financials would deteriorate significantly. Its access to and its cost of capital would be harmed. PGE investors would be harmed because, at a minimum, PGE's bond prices would decrease, and PGC's common stock price would decline as well[1]. PGE investors would be further harmed since PGE's operating income under the disallowance scenarios would be

[1] At that time, PGE's stock did not trade. It was held by Portland General Corporation (PGC), whose stock traded on the NYSE.

significantly less than if full recovery of and on the investment were allowed, thereby reducing the expected return.

Q. Are your analyses still relevant to determining PGE's cost of capital as of November 1994?

A. Yes. However, in my analyses, I, as well as financial investors, assumed that PGE could receive a return of and on its unamortized investment in Trojan. In other words, Oregon law did not prohibit the Commission from allowing PGE a return on the Trojan investment the Commission allowed for recovery. The intervening interpretation by the state Court of Appeals requires that I modify my analyses to reflect Oregon regulation in which investors could expect a return of any economically-retired investment but no return on such investments. I update my analyses in Section III A below to reflect the change in investors' expectations.

B. Estimating PGE's Cost of Capital

Q. Mr. Hager, please describe how, in 1993 and 1994, you estimated PGE's Required Return on Equity.

A. I considered the following:

1. The returns and the underlying risk factors that are important to investors when they estimate the required return from a potential investment;
2. The financial and economic markets;
3. PGE's financing needs of approximately $500 million; and
4. My RROE calculations using two generally used models, the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow model (DCF).

I estimated a reasonable range for the CAPM and the DCF and determined the point estimate for PGE's RROE by considering the two estimated ranges, PGE's financing needs, the financial and economic markets, and investors' expected risks and returns.

1. The underlying factors

Q. What kinds of returns can a stockholder expect?

A. Common stock provides two kinds of return: capital gains and dividends. Capital gain (or loss) is the return the stockholder receives due to the change in the stock price. The capital effect can be either positive or negative. Dividends are payments made quarterly to stockholders. Together, the return an investor receives from capital gains and from dividends is his total return.

Q. What factors influence the investor's expected return on common equity?

A. As I noted in Section II above, the required return on any security investment can be conceptualized as:

$$k = r + \pi + i + b + f + l \qquad \textbf{(1)}$$

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

We can consider these terms a couple of different ways. First, as I defined them above, the first two terms of equation (1) 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. A second way to conceptualize equation (1) is to again equate the first two terms to the nominal interest rate, but to now consider the next three terms (i.e., interest rate, business and financial risk) as default premium risk and market premium risk. In this case, an alternative expression for equation (1) is:

$$k = n + dpr + mpr + l \qquad (\mathbf{1'})$$

where k = required return
n = nominal interest rate
dpr = default premium risk
mpr = market premium risk
l = liquidity risk

Q. Are all possible factors that could influence investors' expectations regarding returns included in equations (1) and (1') above?

A. In theory, yes. For example, the Oregon Court of Appeals interpretation regarding no return on investment that has been economically retired could be considered business risk. Investors might not have expected this risk, but in theory the risk can be classified as business risk. Another example of business risk would be the recent rise in energy prices, including natural gas, wholesale power, and oil.

2. The general process

Q. How did you develop your estimates for PGE's cost of capital in UE 88?

A. We generally followed the same process and used the same models for both our initial and rebuttal testimony, as I described in our opening 1993 testimony (PGE Exhibit 700). We selected a sample of electric utilities based on specified criteria, estimated the RROE for each utility using the CAPM and DCF models, then constructed a range for the CAPM and DCF estimates based on the results.

3. Specific assumptions in the estimation

Q. What specific assumptions were embodied in your cost of capital estimates?

A. When we made our cost of capital estimates in 1993 and 1994, we assumed that all factors not included in our models would remain unchanged. For example, we implicitly assumed that PGE was an average electric utility facing average risk similar to a combination of electric utilities from the S&P and Moody's indices. To the extent that either PGE, the sample groups, or the economic, financial, and/or political environment changed significantly, the forecast would have to be modified as well.

Q. How might PGE "change significantly?"

A. One way that PGE would change significantly from the average utility would be if its business or regulatory climate changed significantly. For example, suppose all retail customers had been given the option on April 1, 1995 to go to direct access while PGE still had remained the supplier of last resort. This situation would have significantly increased PGE's business risk.

Another example, as described by Dr. Makholm in his testimony, is if the Commission was to decide that PGE had to amortize undepreciated but no longer economic plant over that plant's original depreciation life, without a return on the plant investment. This would also increase PGE's risk beyond that of an average electric utility.

A third example would be if PGE faced a significantly different economic, financial, and/or political environment from that of the sample group, such as a continuing drought or economic recession.

III. "No Return On" Effects

A. Effects on PGE's Capital Structure and Financial Ratios

Q. You stated that in November 1994 you calculated PGE's financial ratios and compared them to those used by financial rating agencies. Have you updated your analysis?

A. Yes. PGE Exhibit 6401 provides PGE's financial ratios using 1995 historical financial information and assuming four scenarios for return on PGE's investment in Trojan and compares these ratios to the appropriate Standard & Poor's (S&P) guidelines. Table 5 below reproduces these financial ratios.

Table 5

17-Year Amortization Scenarios

Financial Ratio		1995 Actual	No Return On	No Equity Return	Proper Plant-in-Service No Return On	Proper Plant-in-Service No Equity Return
FFO to Debt	↑	22.43	17.97	18.80	17.97	19.13
Interest Coverage	↑	4.16	3.53	3.65	3.53	3.69
Pretax Interest Coverage	↑	3.01	0.95	1.85	1.46	2.14
Total Debt to Capital	↓	56.18	58.98	57.72	58.26	57.33
Net Cash Flow to Cap Ex	↑	90.75	66.62	71.12	66.62	72.91

Note: Arrows indicate direction for movement to achieve improved bond rating.

Q. How do these financial ratios compare with those listed by S&P for an "A" rating on secured long-term bonds?

A. As the graphs in PGE Exhibit 6401 show, for PGE's financial ratios based on 1995 actuals, four of the five ratios are probably within the "A" or "A-" rating. The only ratio that is clearly outside of the "A" rating is the Total Debt to Capital ratio. At the time, PGE was constructing Coyote Springs I, which would help explain the large amount of short-term debt.

Q. You also calculated financial ratios under four alternative scenarios. Which four alternatives did you consider?

A. I calculated the financial ratios for both the 1-year and 17-year amortizations for PGE's investment in Trojan. My work papers contain both sets of calculations. However, for presentation purposes, I considered only the long-term (17-year) amortization scenarios. The alternatives that I considered are:

1. No return on PGE's Trojan investment. PGE does not receive a return on its investment and is required to collect its unamortized investment over 17 years.
2. No "equity" return on PGE's Trojan investment. PGE recovers its cost of debt on its investment and is required to collect its unamortized investment over 17 years.
3. No return on PGE's Trojan investment and proper plant in service. PGE's recommended plant classification is accepted, resulting in approximately $80 million higher plant in service on April 1, 1995. However, PGE does not receive a return on the balance of its Trojan investment and is required to collect the balance of its unamortized investment over 17 years.
4. No "equity" return on PGE's Trojan investment and proper plant in service. PGE's recommended plant in service is accepted, resulting in approximately $80 million of Trojan as plant in service as of April 1, 1995. However, PGE recovers its cost of debt on the balance of its Trojan investment and is required to collect the balance of its unamortized investment over 17 years.

Q. Are the financial ratios significantly different under the four alternatives

A. Yes. Under each of the scenarios, PGE's financial ratios decline significantly, most likely leading to a downgrade in PGE's bond rating.

Q. These financial ratios are based on 1995 PGE actuals. Do they show the full 12-month financial impact of the recovery scenarios?

A. No. PGE's retail rates for its UE 88 general rate case went into effect on April 1, 1995 but were superseded by UE-93 rates in late November 1995. Thus, we used only nine months instead of twelve in our evaluation, but the ratios we show are comparable to the ones used by the S & P guidelines.

Q. Why did you use 1995?

A. We wanted to reflect the impact of the scenarios on PGE's finances under retail rates associated with UE 88.

Q. Would the impact of the scenarios be the same in the following years as in the first year?

A. Yes and no. The financial impact would be somewhat less, but the effect on PGE's bond rating would most likely be the same. PGE would remain at the lower bond rating.

B. Effects on Required Rate of Return

Q. In the fall of 1994, did investors expect that PGE would receive a return on and of their investment in the Trojan Nuclear Plant?

A. Yes. All of the investment literature discussed PGE's financial outlook as "positive." No one mentioned, let alone discussed, the remote possibility that PGE could not receive a return on its Trojan investment as the result of judicial interpretation of ORS 757.355. A rational investor would have concluded that PGE would receive a return on Trojan.

Q. Would investors have required a different return on PGE's equity had they known that PGE would not receive a return on its Trojan investment?

A. Yes. Investors did not factor this new risk into their expectations.

Q. How would investors factor this risk into their expectations?

A. Investors would most likely consider this risk in several ways. The Trojan plant was a significant part of PGE's regulated rate base and, hence, a significant part of PGE's earning potential. Removing approximately 15% of PGE's rate base would decrease PGE's earning potential and increase the risk to investors in a number of areas, including extreme company financial hardship, late payments, lower reinvestment returns, economic loss due to illiquidity in PGE's and PGC's securities, capital loss in the value of their financial securities, etc.

Given these additional and/or increased risks, an investor would have required a higher return than the authorized 9.5% ROR and the 11.6% ROE. How much higher a return they would have required depends on several factors, including: how fast PGE could recover its investment (directly related to the amortization period for PGE's investment in Trojan); whether PGE would receive its cost of debt related to its Trojan investment; the liquidity of PGE securities (PGE preferred stock, commercial paper, and long-term debt as well as PGC common stock); and, the extent to which the Commission and/or PGE had taken steps to minimize the reoccurrence of this scenario.

Q. How would you estimate investors' expectations in November 1994, given the same conditions, except for the Oregon Court of Appeals interpretation that no return on PGE's Trojan investment was allowed?

A. I would use the same information available to investors in November 1994, calculate the expected ROE range using the DCF and CAPM models, and then calculate the appropriate point estimate using the quantitative and qualitative factors discussed above. I would also consider the information provided by the other cost of capital witnesses in this docket, including Drs. Makholm (PGE Exhibit 6500), Blaydon (PGE Exhibit 6600), and Hess (PGE Exhibit 6700).

Q. Have you performed such a calculation?

A. Yes. I determined two point estimates for PGE required ROR and ROE, depending on the amortization period over which PGE would be allowed to collect its investment in Trojan. If PGE could collect its investment over one year, PGE's required ROE would be 11.85%, slightly higher than that authorized for the 1995-1996 period, but still below the mid-point of my combined DCF/CAPM ranges and just above the mid-point of the DCF range.

If, however, the Commission in UE 88 had set a longer amortization period, such as 17 years, then PGE's required ROE would have been 13.10%, about 150 basis points higher than that authorized for the 1995-1996 period. Table 6 below shows PGE's estimated cost of capital and its components, if the Commission had been making a decision on RROE knowing that it could not set rates on a basis that included a return on undepreciated Trojan investment.

Table 6
Summary Results for PGE's Updated RROE

	Amortization Period	
	1-yr	17-yr
Required Return on Equity	11.85%	13.10%
Required Rate of Return	9.62%	10.19%

Q. Please explain how you derived your estimates for PGE's RROE, if no return is allowed on PGE's investment in Trojan.

A. First, as I discussed above, it's clear that investors would demand a higher rate of return on their investment because of the increased risk that they face with investing in a company subject to the Oregon regulatory scheme. Dr. Hess makes a similar analysis in his testimony, using the CAPM model to demonstrate this. In addition, Dr. Makholm discusses the regulatory compact and the impact that no return on economically-retired assets would have.

Second, in 1993 and 1994, when I estimated the appropriate ranges for PGE's RROE in my rebuttal testimony, I used electric utilities from the Moody's and Standard & Poor's indices that met my specified financial criteria (PGE Exhibit 700, Section VI-Appendix). The result was an expected range for an electric utility with average risks. It's clear that PGE is no longer an electric utility with average risk. Indeed, if investors cannot receive a return on the undepreciated balance in assets retired for economic reasons, then PGE will have significantly higher risk than the average electric utility. Thus, given the updated results for PGE's expected 1995 financial ratios and my conclusions in the prior paragraph, I would conclude that the appropriate point estimate for PGE under these circumstances would be towards the high end of the range rather than towards the median or mean.

Q. Why are your estimates different for short versus long amortization of investment retired for economic reasons?

A. The effect of the Oregon Court of Appeals interpretation assuming a short amortization period is that investors face greater reinvestment risk and some loss of economic value associated with any lag in PGE's recovery of the investment. The loss in economic value becomes much greater if the Commission adopted long amortization periods for economically-retired assets, notwithstanding the Oregon Court of Appeals interpretation.

Q. What is reinvestment risk?

A. Reinvestment risk is the economic or opportunity loss from having to reinvest in a lower yielding security. When investors buy a security such as a bond or common equity, they usually receive at least a partial return in the form of a coupon payment or dividend. The investor will then invest the coupon or dividend. The extent to which the returns from these new investments are different from those on the original bond or common stock is reinvestment risk.

An example, using a bond holder, is easiest to understand. Suppose you bought a $1,000 PGE 20-year (long-term) bond at par (i.e., $1,000) that had a coupon rate of 7%. Each year, you would receive $70. Now, suppose interest rates decline. In this case, you could still reinvest the $70, but the return on that $70 would be lower than 7%. This is reinvestment risk. Both short-term and long-term investors have this reinvestment risk.

Q. What additional reinvestment risk would PGE investors face, given a short amortization period under the Oregon Court of Appeals ruling?

A. The PGE investor could face an early return of his principal. That is, what is unusual or outside of investors' expectations here is the possible sudden return of the investor's principal, depending on PGE's capital needs after a plant retired for economic reasons. Otherwise, the investor would expect his principal to remain invested for a much longer time.

Q. Please explain.

A. Let me return to the $1,000 PGE bond example. When you bought this bond, you expected to have an investment that would yield 7% per year until the bond matured. Under the short-term recovery scenario, PGE receives all of its remaining unamortized investment in Trojan over one year, or approximately $340 million. PGE will redeploy this cash by borrowing less or redeeming debt. This bond holder now has the risk that PGE will redeem its bond immediately, instead of waiting until the bond's maturity debt. In this situation, the investor now faces the risk of a lower return, not just on the $70 coupon payment, but also on the full $1,000 investment. The investor would, thus, demand a higher return than otherwise to buy PGE's bond.

Q. Would this reinvestment risk also apply to common and preferred shareholders?

A. Yes. As an example, in addition to redeeming debt, PGE could also buy back some of its common and/or preferred stock. As with the bondholder, the shareholder would receive his principal back much sooner than expected and would have to reinvest his principal. The shareholder is likely to have suffered a capital loss since PGE's earning capacity would be diminished, reducing expected returns, resulting in a reduced price of PGE stock.

Q. How did you determine the required ROE for the long-term (or 17-year recover) investor?

A. As I noted above, the required ROE would be towards the high end of the range. I used the top quartile of my updated range as the appropriate range for the higher required ROE. This range is 12.9% to 13.4%. The midpoint of the range is 13.15% or approximately 150 basis points above the 11.6% in the cost of capital stipulation. I thus used 13.1% as my point estimate.

Q. Why did you use the bottom quartile of the range for the 1-year amortization scenario?

A. The stipulated ROE was 11.6%, which represented the RROE for an average electric utility. If PGE now faced the risk of a 1-year amortization of a significant portion of its rate base, then investors would face the risk of early redemption. They would require a premium over the RROE for an average electric utility. I used the upper part of the bottom quartile of the overall range as my range for the 1-year amortization scenario.

Q. Please explain how you calculated the range for the 1-year amortization scenario.

A. The bottom quartile of my range was 11.46% to 11.94%, with a median of 11.7%. I took the midpoint of the range between the median and the top end of the bottom quartile, yielding 11.82% or approximately 25 basis points above the 11.6% in the cost of capital stipulation. I thus used 11.85% as my point estimate.

Q. For how long would investors require a higher return on their investment?

A. Investors would require higher returns on their investment until the increased risk that they perceive has either been mitigated or removed.

Q. How might these risks be removed?

A. The best way to remove these risks is to amend or revise the Oregon Revised Statutes to allow for recovery of plant that has been economically displaced together with financing costs, if the Commission spreads such recovery over time.

Q. If the Commission adopted a higher required return for PGE for the 1995 through 2000 period, would the Commission be setting a precedent for PGE's future required ROE?

A. No. By taking this action, the Commission would demonstrate that it would take actions to mitigate risks outside of PGE's normal business. Absent the unique circumstance presented by the premature closing of Trojan and the determination that no return on the remaining plant balance can be provided, future investors would not require a higher return.

Q. Are financial rating agencies concerned about PGE's recovery of its Trojan investments?

A. Yes. PGE Exhibit 6402 is a copy of the January 26, 2005, S&P Research Report on PGE. S&P specifically notes as a major "weakness" the litigation risk of PGE's recovery of its investment in Trojan and discusses the litigation. S&P notes that the outcome of the Trojan case could have a major impact on PGE's bond rating.

IV. Qualifications

Q. Mr. Hager, please summarize your qualifications.

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. I am responsible for determining PGE's revenue requirements as well as estimating PGE's Required Return on Equity.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PORTLAND GENERAL ELECTRIC
FINANCIAL FORECAST

Financial Ratios	Calculated from 1995 10-K
FFO / Interest Coverage	
Net Income	81,036
Adjustments:	
Add: Depreciation	
Add: Amortization	143,619
Add: Deferred Income Tax	(9,555)
Add: Deferred ITC	(5,549)
Less: AFDC(Debt and Equity)	(11,065)
Less: Other non-cash credits to income (PCA and PRM activities)	49,567
Less: Equity Income	
Cash Flow From Operations	248,053
Incurred Interest	
Total Interest Charges	79,128
Less: Interest Charges on QUIDS	(6,188)
Less: AFDC - Debt	7,808
Total Interest Incurred	80,749
Cash Flow From Operations + Total Interest Incurred	328,802
FFO / Interest Coverage Ratio	**4.16**
Pre-tax Interest Coverage Ratio	
Net Income	81,036
Adjustments:	
Add: Gross Interest Expense	79,128
Add: Income Taxes	89,064
Less: AFDC Equity and Debt	(11,065)
Less: Equity Income	
Adjusted Earnings Before Interest & Taxes	238,163
Total Interest Incurred	79,128
Pre-tax Interest Coverage Ratio	**3.01**

*** 1995 as estimate in PGE Exhibit 2300**

Financial Ratios	Calculated from 1995 10-K
Total Debt / Total Capitalization	
LTD (excluding conservation bonds and current portion of LTD)	890,556
Less: 30% of QUIDS Balance	(23)
Add: Current Portion of long term debt (2) (excluding Conservation Bonds)	95,114
Add: Short Term Debt Balance	170,248
Total debt	1,155,896
Preferred Stock	40
Common Stock	191,301
Other Paid In Capital	574,468
Retained Earnings	135,885
Accumulated Other Comprehensive Income	
Total Shareholder's Equity	901,694
Add: LTD (excluding conservation bonds and current portion)	890,556
Add: Current LTD (excluding conservation bonds)	95,114
Add: Short term debt balance	170,248
Total Capitalization	2,057,612
Total Debt / Total Capitalization	**56.18%**
FFO / AverageTotal Debt	
Funds From Operations	248,053
Average Total long term debt	1,105,907
FFO / Total Debt	**22.43%**
Debt/Equity	
Common Equity	933,148
long term debt (2) (excludes LTD w/in 1 Year, includes 100% Quids)	890,556
Preferred Stock (excludes sinking fund)	40,000
Total Capitalization - OPUC	1,863,704
Common Equity Ratio - Per OPUC	**50.07%**
Add 30% of QUIDs	(23)
Cap calculation changes for Rating Agency	
Add Long-Term Debt due within one year	105,114
Add Preferred Sinking Fund	
Add Short-Term Debt	170,248
Total Capitalization - Rating Agency	2,139,066
Common Equity Ratio - Per Rating Agency	**43.62%**

*** 1995 as estimate in PGE Exhibit 2300**

Financial Ratios

	Calculated from 1995 10-K
Net Cash Flow / Capital Expenditures	
Funds From Operations	248,053
Less: Dividends Paid	(62,396)
Net Cash Flow	185,657
Cash Flows from Investing Activites	215,645
Less: AFDC(Debt and Equity)	(11,065)
Capital Expenditures	204,580
Net Cash Flow / Capital Expenditures	**90.75%**

*** 1995 as estimate in PGE Exhibit 2300**

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1995 S&P Benchmarks	AA	A	BBB	BB	Calculated from 1995 10-K	17 Year Amortization Scenarios No "return on"	No "equity return"	Plant in Service, no "return on"	Plant in Service, no "equity return"
FFO/Debt									
Above	26%	19%	14%	11%					
Average	32%	25%	19%	13%	**22.43%**	17.97%	18.80%	17.97%	19.13%
Below	--	34%	29%	20%					
Interest Coverage									
Above	4.00	3.25	2.25	1.75					
Average	4.50	4.00	3.00	2.00	**4.16**	3.53	3.65	3.53	3.69
Below	--	5.00	4.00	2.75					
Pretax Int Cov									
Above	3.50	2.75	1.75	1.25					
Average	4.00	3.50	2.50	1.75	**3.01**	0.95	1.85	1.46	2.14
Below	--	4.50	3.50	2.50					
Total Debt/Cap									
Above	47%	52%	59%	65%					
Average	42%	47%	54%	60%	**56.18%**	58.98%	57.72%	58.26%	57.33%
Below	--	41%	48%	54%					
Net CashFlow/Cap Ex									
Above	90%	70%	45%	30%					
Average	110%	85%	60%	50%	**90.75%**	66.62%	71.12%	66.62%	72.91%
Below	--	105%	80%	60%					

Table A

Test Year 1995

	Capital Structure	Cost	Weighted Cost
Long-Term Debt	49.14%	7.71%	3.79%
Preferred Stock	5.42%	8.27%	0.45%
Common Equity	45.44%	11.60%	5.27%
	100.00%		
Rate of Return			**9.51%**

Table B

Test Year 1996

	Capital Structure	Cost	Weighted Cost
Long-Term Debt	48.86%	7.82%	3.82%
Preferred Stock	4.67%	8.27%	0.39%
Common Equity	46.47%	11.60%	5.39%
	100.00%		
Rate of Return			**9.60%**

Table C

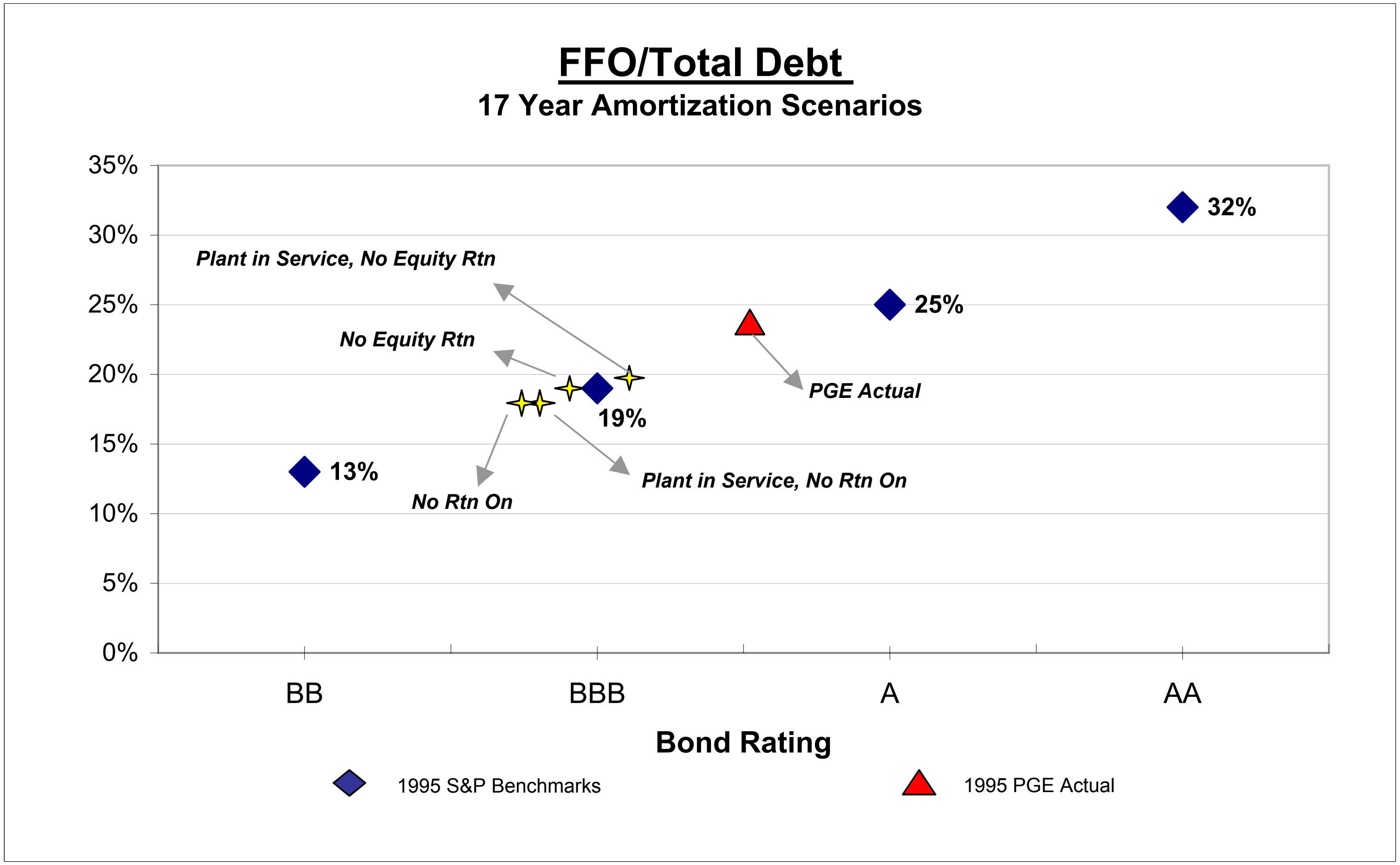
Test Year 1995

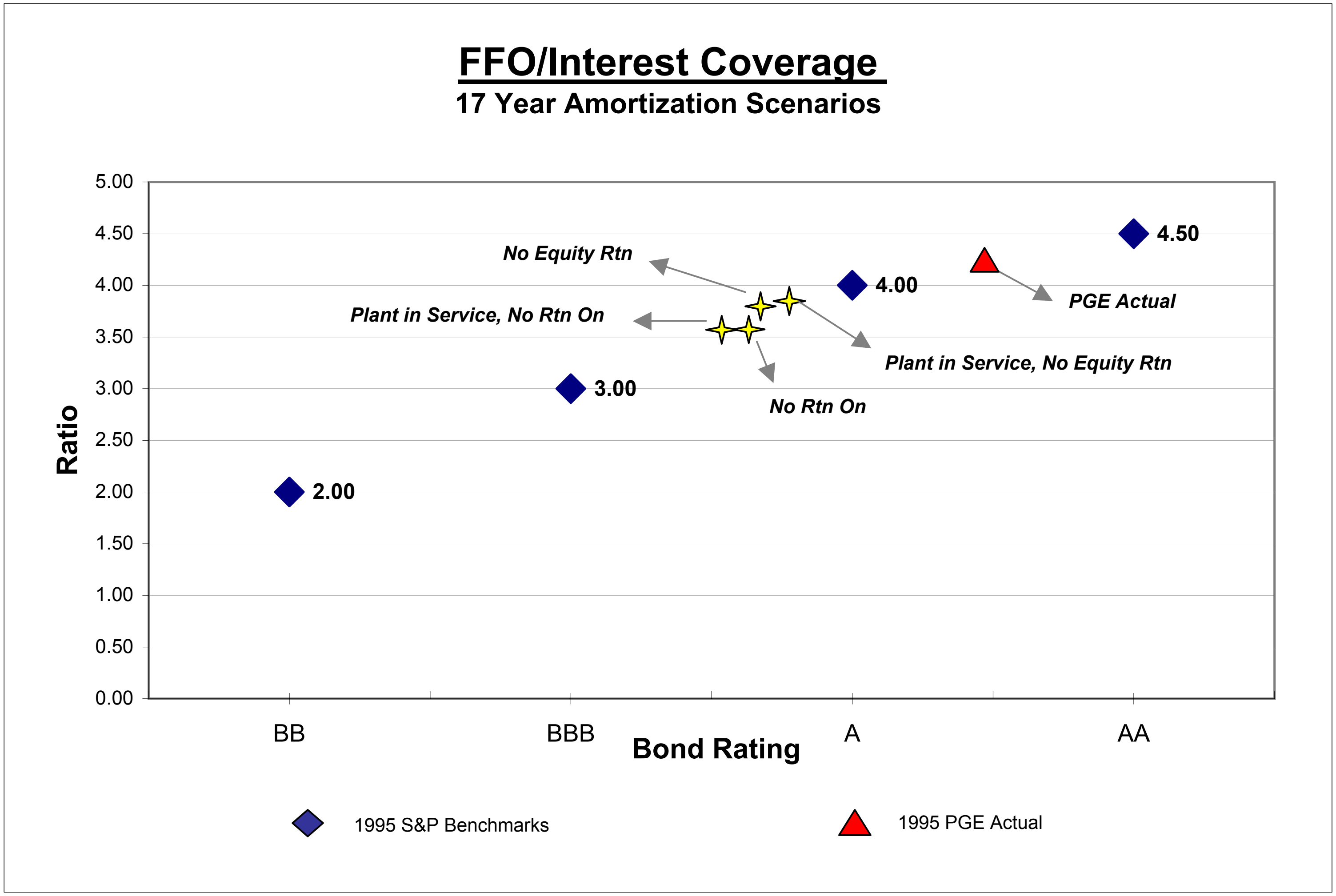
	Capital Structure	**Cost**	**Weighted Cost**
Long-Term Debt	49.14%	7.71%	3.79%
Preferred Stock	5.42%	8.27%	0.45%
Common Equity	45.44%	11.85%	5.38%
	100.00%		
Rate of Return			**9.62%**

Table D

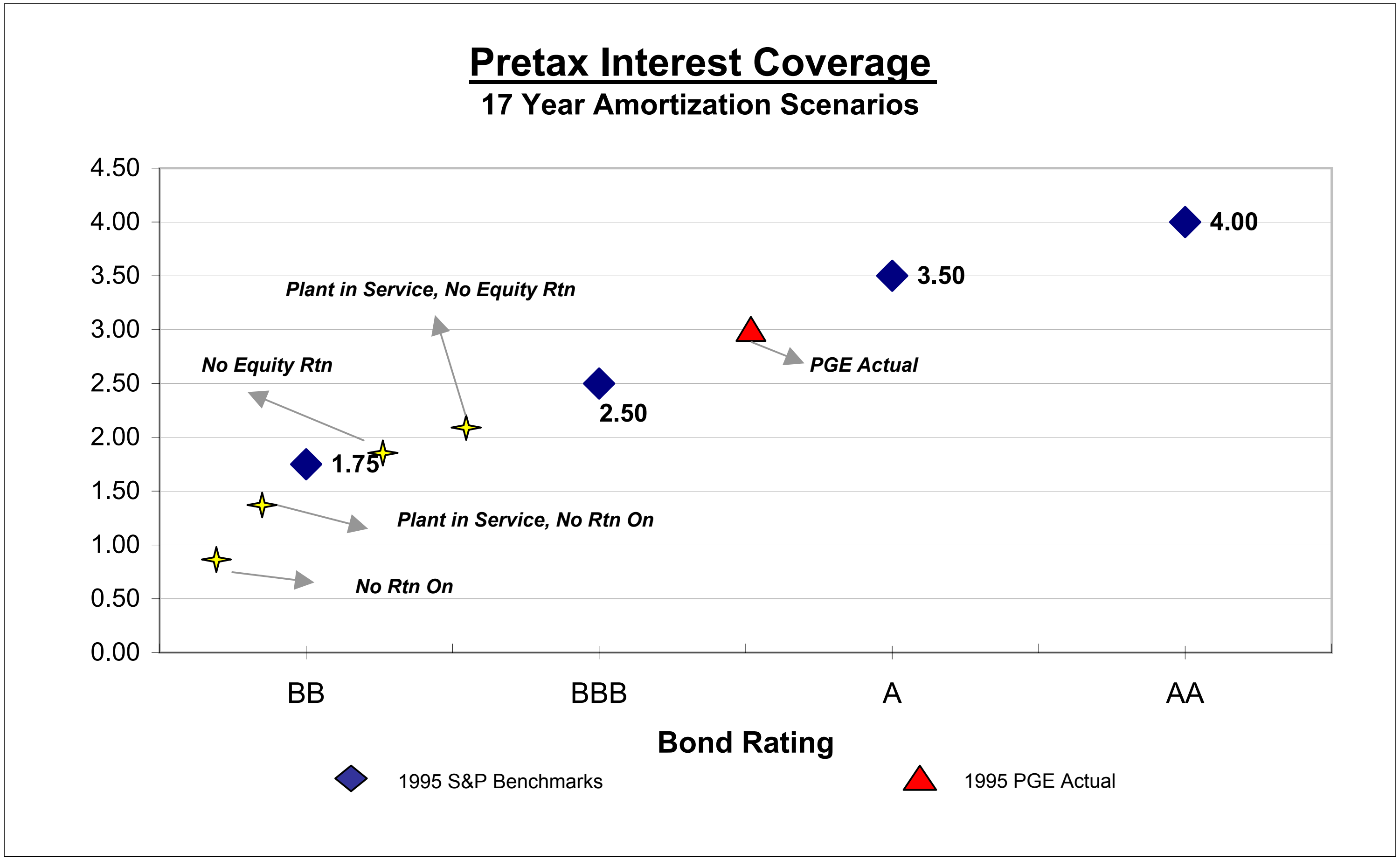
Test Year 1995

	Capital Structure	**Cost**	**Weighted Cost**
Long-Term Debt	49.14%	7.71%	3.79%
Preferred Stock	5.42%	8.27%	0.45%
Common Equity	45.44%	13.10%	5.95%
	100.00%		
Rate of Return			**10.19%**


FFO/Total Debt
17 Year Amortization Scenarios
35%
30%
25%
20%
15%
10%
5%
0%
32%
25%
19%
13%
Plant in Service, No Equity Rtn
No Equity Rtn
PGE Actual
Plant in Service, No Rtn On
No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

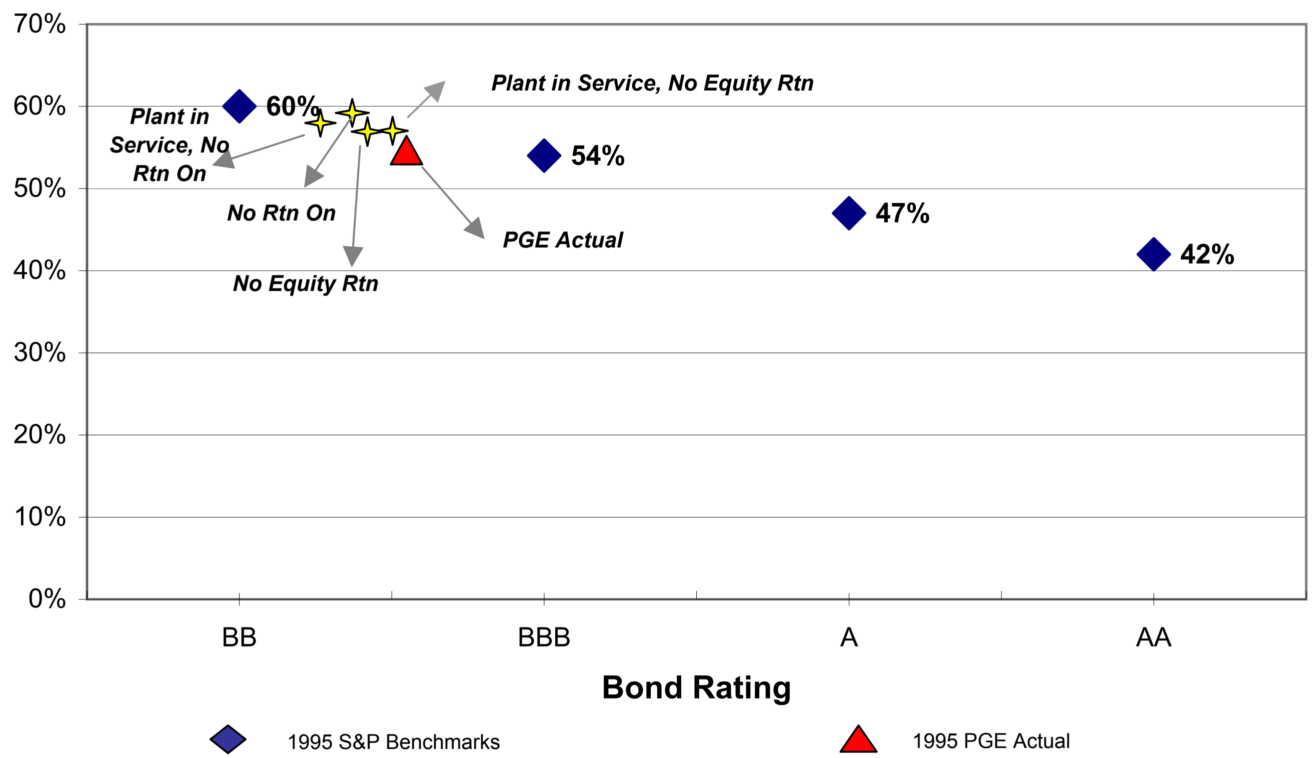

FFO/Interest Coverage
17 Year Amortization Scenarios
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Ratio
4.50
4.00
3.00
2.00
No Equity Rtn
Plant in Service, No Rtn On
PGE Actual
Plant in Service, No Equity Rtn
No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

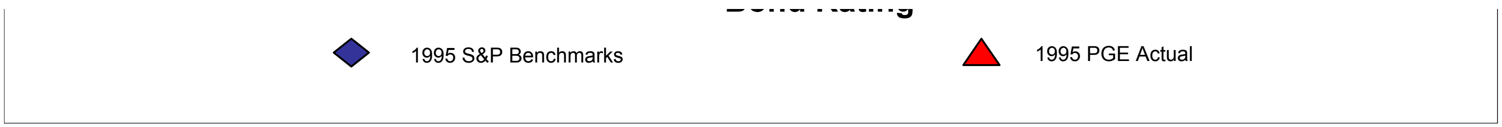

1995 S&P Benchmarks
1995 PGE Actual

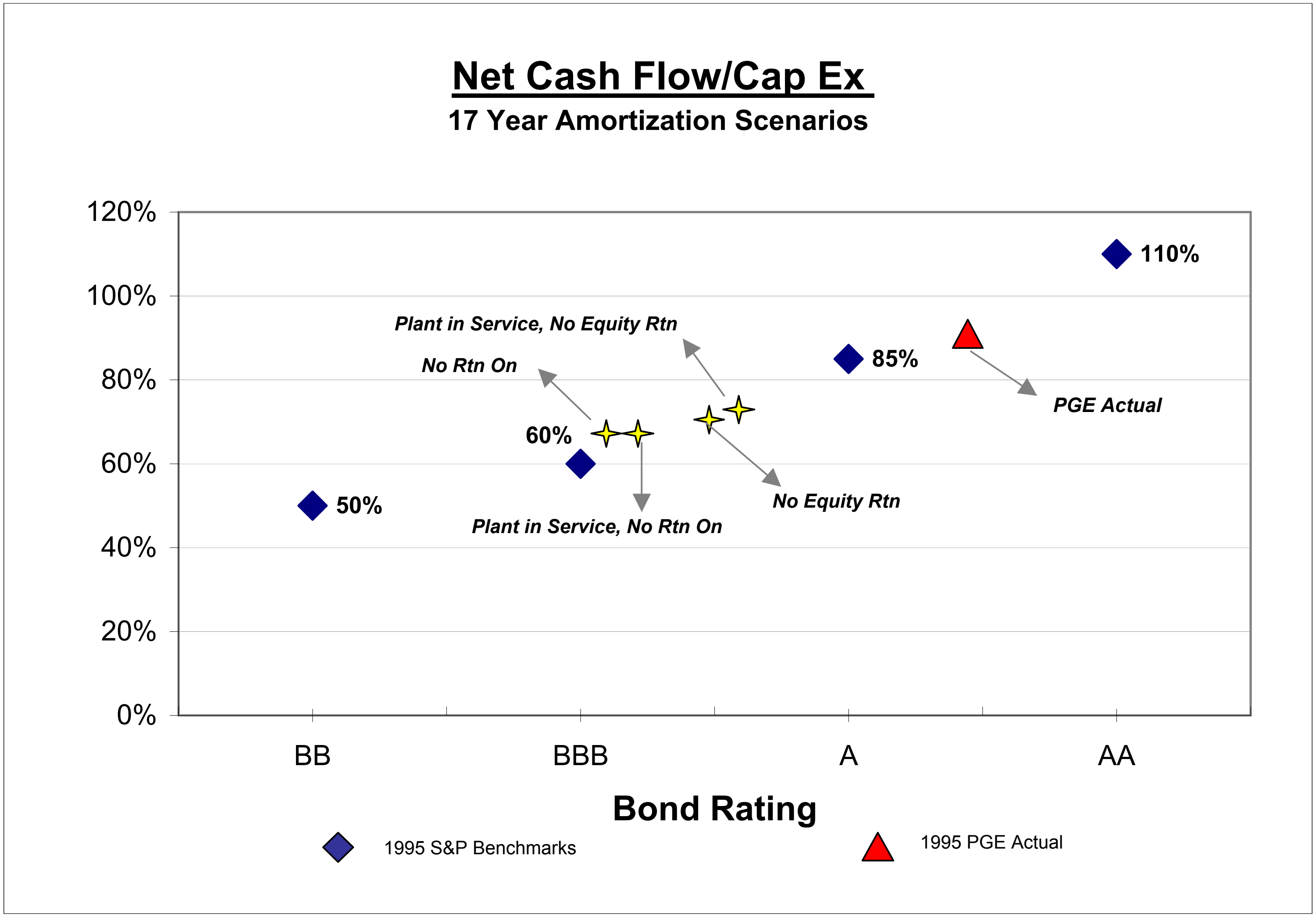

Pretax Interest Coverage
17 Year Amortization Scenarios
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
4.00
3.50
2.50
1.75
Plant in Service, No Equity Rtn
No Equity Rtn
PGE Actual
Plant in Service, No Rtn On
No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

Total Debt/Total Capital

17 Year Amortization Scenarios




1995 S&P Benchmarks
1995 PGE Actual


Net Cash Flow/Cap Ex
17 Year Amortization Scenarios
120%
100%
80%
60%
40%
20%
0%
110%
Plant in Service, No Equity Rtn
85%
No Rtn On
PGE Actual
60%
50%
No Equity Rtn
Plant in Service, No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

I. Qualifications, Purpose, and Conclusions

Q. Please state your name, business address and current position.

A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with principal offices in a number of major U.S. and European cities. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116

Q. Please describe your academic background.

A. I have M.A. and Ph.D. degrees in economics from the University of Wisconsin, Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q. Please describe your work experience.

A. My work centers on economic issues involving pricing, market definition, and the components of reasonable regulatory practices for regulated companies. Much of my international work focuses on regulatory design and structural issues, such as industry restructuring, privatization, and the introduction of incentive-based regulation. Issues of reasonable regulatory practices include the analysis and evaluation of alternative regulatory approaches, the creation of credible and sustainable accounting rules for ratemaking, and the establishment of administrative procedures for regulatory rulemaking and adjudication. I have prepared expert testimony and statements, and I have appeared as an expert witness in many state, federal and United States District Court proceedings, as well as in regulatory and judicial hearings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries on economic and regulatory issues, such as the specific issues of competition, rate design, fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy, and reasonable regulatory practices. In these countries, I have consulted on regulations, tariffs, recommended financing options for major capital projects and advised on industry restructurings. I have also assisted in the privatization of state-owned gas utilities. As part of my international work pertaining to the gas industry, I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Regarding rate of return and utility financing questions specifically, I have testified for electric, natural gas, water and telecommunications utility clients before state commissions in Pennsylvania, Oregon, Ohio, North Carolina, Kansas, New Jersey, New York, Maryland, California, Virginia, Rhode Island, New Hampshire, Texas, Indiana, Maine, Wisconsin, Illinois and Connecticut, as well as before the Federal Energy Regulatory Commission (FERC). My current curriculum vitae, which more fully details my educational and consulting experience, is provided as PGE Exhibit 6501.

Q. What is the purpose of your testimony?

A. I explain the nature of the "regulatory compact," which is investors' expected basis for economic regulation of utilities in the United States. I also review the consequences of one interpretation of Oregon law wherein Oregon utilities retiring assets with an undepreciated balance can receive only a return of those assets in limited amount over an extended period of time with no return on the undepreciated capital balance.

Q. What conclusions have you drawn?

A. I conclude that investors will demand a larger return for Oregon utility investments because of this anomaly from the expected regulatory compact arising from this particular interpretation of Oregon law.

Q. How is your testimony organized?

A. This testimony is organized as follows. In Section II, I explain the economic underpinnings of economic regulation as commonly understood throughout the United States. This Section begins by explaining the fundamental economics of investor-owned utility companies, moves to the regulatory compact and then on to the "capital attraction" function—the key function—of just and reasonable utility rates.

Section III shows how the regulatory compact has generally accommodated other power plants—assets that are highly capital intensive, take years to build, and are sometimes retired before their originally projected useful lives, as in the case of the Trojan plant.

Section IV discusses the implications of the regulatory compact and its applications for Trojan. In this section, I also review how the regulator in Oregon upheld the regulatory compact when reviewing the actions of PGE with respect to Trojan.

II. The Uniqueness of Public Utilities and the Regulatory Compact in the United States

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

A. This section describes the particular qualities of investor-owned public utilities that have led, in the interest of consumers, to the regulatory compact. The regulatory compact has shaped investor expectations in the United States for decades regarding the risk of investing in public utility infrastructure, like power plants.

Q. Can you outline how you discuss this issue of the regulatory compact?

A. Yes. My discussion supports the following well-accepted characteristics of public utilities and regulatory institutions in the United States:

- Utilities are not your normal business—they are directly connected to their public users in particular locations with unusually capital-intensive facilities.
- Regulation has developed over its history, particularly in the U.S., to serve two goals: (1) to maintain essential services to the public; and (2) to limit prices for those services to what is considered fair—that is, limited to the reasonable costs of the companies providing that service.
- The need to balance the competing interests of the public and the investor-owners of public utilities has resulted over time in the regulatory compact in the U.S., which has been the staple of U.S. regulation—as confirmed by the courts.
- Ultimately, it is customers who benefit from the regulatory compact, as it allows investor-owned utilities to anticipate a consistency of regulatory control necessary to attract capital at lower prices than their unregulated industrial counterparts.

In discussing these concepts, this section will provide the groundwork for the discussion in Section III (regarding how the regulatory compact has been confirmed for utility investors for nuclear power plants closures in other jurisdiction), and Section IV (regarding the consequences to Oregon utilities and customers if a particular interpretation of Oregon law prevents the regulatory compact from working in the same way there).

A. Public Utilities Require Consistent Economic Regulation

Q. What do you mean by "regulator" or "regulatory bodies" in this discussion?

A. I mean more than just a state or federal regulatory agency or commission. I mean the entire framework of economic regulation for a public utility, including the laws and policies adopted by legislative bodies and in Oregon's case, by state initiative. The laws and policies of the legislature guide and in some cases severely limit what an agency or commission can do. In other words, the "regulator" is the agency or commission working within the policies and laws of the legislature.

Q. What is unique about public utilities?

A. Public utilities are unique in that they serve the public—and indeed are physically connected to the customers they serve—with extensive and expensive facilities whose only purpose is to provide reliable services (like electricity, gas, water and telecommunication) to their customers. They have obligations that normal industrial firms do not. That is, they must provide uninterrupted service to all comers and also have a greater need to plan and invest to make sure that those services continue.

In addition, they are typically local monopolies, reflecting the widely held—and essentially correct—conviction that the duplication of such services, with competing electric wires or gas pipelines for example, would be inefficient and wasteful. Their local monopoly status requires that the same regulators that compel them to provide uninterrupted and high quality services also must regulate pricing to limit their charges to what is considered cost based and reasonable.

Q. Are public utilities in the U.S. generally owned by investors?

A. Yes. From the growth of public utility industries in the U.S. in the 19th century, investor ownership has dominated the industry. There are many localities—and some broader jurisdictions—that provide utility services by governmental authorities, but they are in the minority in the U.S. The normal model in the U.S. is for investor-owned firms like PGE to provide public utility services.

Q. Is consistency and predictability of regulation important for investor-owned utilities like PGE?

A. Yes. The public would not be well served—either in the quality of services they receive or in the prices for those services—without consistency and predictability in regulation.

Q. Why is that?

A. It is because the long-lived nature of utilities' investments requires a long-term assurance of payments from utility customers in order to give investors confidence that their investments ultimately will be recouped.

Investor-owned public utilities are highly capital intensive—more so than industrial firms generally. In addition, the capital assets that utilities employ to serve the public are highly specialized and cannot generally be redeployed to alternative uses or locations—which is to say, the local wires of electric utilities or pipelines of a gas utility have little value if they're not used where they are. As such, the industry is highly exposed to expropriation of its capital investments if inconsistent regulation would prevent it from recouping the costs of its investments over the long lives of those investments.

Capital investments, however, are not simply done once and forgotten. The continuing need for new customers to be served, and for old capital to be replaced to maintain existing services, necessitates an ongoing flow of dollars into new capital assets. As such, utilities must have uninterrupted access to capital markets to maintain and upgrade capital facilities to serve existing and new customers – all of whom they are compelled to serve by their public utility service obligations.

Q. Please describe these "capital markets."

A. These are markets where utilities go to sell shares to raise stockholder equity, or where they sell bonds to borrow money. The prices that investors and lenders require in the capital markets are unregulated. These markets are very large in relation to the size of any individual utility, which in the terminology of economics makes utilities "price-takers." That is to say, when utilities go to the capital markets to raise equity funds or borrow money through the issuance of bonds, they pay the going competitive rate that investors require for companies of their type and perceived level of risk.

As price takers, utilities can only attract capital at reasonable rates by showing that investors' capital is reasonably safe from loss and will be repaid with a market-based rate of return through a transparent system of regulated prices. Because of the potential exposure of utility investments to expropriation, economic regulation for such utilities must be highly credible in the eyes of the investors. Without such regulatory credibility, utilities cannot attract private investment—jeopardizing the provision of essential public services.

Q. Is such regulation to which you refer a long-standing institution?

A. Yes—it is quite long-standing. The economic regulation, in some form, of businesses that serve the public is a fundamental part of the common law. As early as the 17th century, Lord Chief Justice Hale (in his treatise *De Portibus Maris*) recognized that "…the wharf and crane and other conveniences are affected with a public interest and they cease to be *juris* *privati* only."[1] All economic regulation of businesses (then and now) proceeds from the premise that citizens deserve adequate services at reasonable prices, but also that regulated businesses deserve a compensatory—that is to say reasonable—rate for the services they provide.

There are two basic duties of regulation that stem from this history. The first duty of regulators is to ensure that companies that supply the public do so safely and adequately. The second is to ensure that the prices paid by consumers are just and reasonable, based on prudently-incurred costs. Part of this second duty of regulators is to ensure that their actions and decisions do not diminish the property rights of those companies who provide the regulated services to the public. This latter duty is both a legal and a practical one. That is, without an assurance that regulators will not seize the property of regulated companies, the company cannot maintain sufficient financial integrity to be able to engage in the ongoing capital commitments necessary to provide uninterrupted service at a reasonable price

B. The Regulatory Compact

Q. What does the available literature say about regulation of investor-owned public utilities?

A. The literature on regulation of investor-owned public utilities refers consistently to the concept of the regulatory compact, defined, as follows:

> First, in return for a monopoly franchise, utilities accept an obligation to serve all comers. Second, in return for agreeing to commit capital to the

[1] See: Phillips, Charles F. Jr., *The Regulation of Public Utilities*, Public Utilities Reports, 1993, page 91, ("Phillips").

> business, utilities are assured a fair opportunity to earn a reasonable return on that capital.[2]

In mature regulatory jurisdictions with an extensive legal and administrative history, such as the U.S., the regulatory compact represents a combination of Constitutional rights, federal and state statutes, franchise agreements, regulatory commission rules, policy statements, and so on.

The regulatory compact is supported in the U.S., in particular, by a considerable history of: (1) strong primary legislation; (2) credible, comprehensive and transparent administrative procedures for making regulatory decisions and adjudicating disputes; (3) accounting regulation specifically designed for utility rate making; and (4) clear pathways for reliable judicial review of regulatory decisions. Newer regulatory jurisdictions around the world that do not have comparable bodies of regulatory precedent routinely use explicit contracts to express such principles.

These principles are generally true of all utilities regulated in the U.S. Both equity investors and lenders generally devote funds to U.S. utilities with the expectation that these principles of the regulatory compact will be honored. Even though the particular utility statutes may vary from state to state, and even though regulatory commissions may have different policies and precedent in different states, investors anticipate the regulatory compact will apply to their investments. For this reason my analysis does not depend on any particular state utility statutory scheme.

[2] Stelzer, I.M., *The Utilities of the 1990s*. The Wall Street Journal, January 7, 1987, 20, as referenced in Phillips, C.M., *The Regulation of Public Utilities, Theory and Practice*, Public Utilities Reports, Inc. Arlinton, Virginia (1993), Pg. 21.

C. The "Capital Attraction" Function of Regulated Prices

Q. What is the key requirement for the success of regulation of investor-owned utilities?

A. The key requirement for the success of the regulation of any investor-owned utility is to assure that the company in question maintains its financial integrity so as to be able to continue to fund its operations and serve the public.

1. Attracting Capital in the Market

Q. What role does attracting capital play in the regulated prices charged by investor owned utilities?

A. Capital attraction determines the basic constraint that investor ownership places on the level of regulated charges. Professor James C. Bonbright, a widely referenced expert on the principles of public utility prices, describes what he called the "capital attraction function" for investor-owned public 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. [3]

Professor Roger Morin echoes the importance of capital attraction more recently:

> It must be understood that both capital attraction and financial integrity standards must be fulfilled in determining a fair rate of return. Despite a deterioration in credit standing, a utility may be able to attract capital temporarily, but at prohibitive costs and under unfavorable terms. Eventually, the utility will face hard funds rationing and/or the costs of

[3] Bonbright, J.C., *Principles of Public Utility Rates*, Columbia University Press, New York (1961), pp. 49-50.

> financing will become prohibitive, and the utility can not longer attract capital at a reasonable price.[4]

Further, Professor Bonbright states that the capital attraction function for utility ratemaking has always been a key concern for regulators as well as regulated companies.

> … In public utility cases in which the general *level* of rates (as distinct from the rate *structure)* is at issue, the capital-attraction standards of reasonable rates tends to be accepted by [regulatory] commissions as the primary basis for their decisions. Even the representatives of the public utility companies will usually base their requests for a rate increase or their opposition to a rate decrease on the ground of a need for credit-sustaining revenue.

Q. How does return on investment affect attracting capital in the capital markets?

A. Given the high operating leverage for public utilities (*i.e.*, the use of a high proportion of fixed investment costs relative to variable costs), the ability of regulated utilities to reliably provide a return to their owners is essential to obtaining credit ratings that facilitate the acquisition of capital. Independent credit ratings agencies, such as *Standard & Poor's* (*S&P*), provide comprehensive discussions of the factors that lead them to grant "investment grade" ratings for investor-owned electric utilities.[5] Consistent regulatory treatment is key to *S&P's* ratings:

> Regulation defines the environment in which a utility operates and has great influence on the company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy as a result of a supportive regulatory environment. Conversely, *unpredictable or antagonistic regulatory action can*

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[4] Morin, R.A., *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports, Inc., Arlington, Virginia (1994), pg. 12.

[5] Standard and Poor's defines "investment grade" as follows (See: Standard & Poor's Corporate Ratings Criteria, Update to the 1994 edition, p. 12): The term "investment grade" was originally used by various regulatory bodies to connote obligations eligible for investment by institutions such as banks, insurance companies, and savings and loan associations. Over time, this term gained widespread usage throughout the investment community, Issues rated in the four highest categories. "AAA", "AA", "A", "BBB", generally are recognized as being investment grade. Debt rated "BB" or below generally is referred to as speculative grade. The term "junk bond" is merely a more irreverent expression for this category of more risky debt.

> *undermine the financial position of utilities that are very strong from an operational standpoint*. To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory polices and the length of time that the regulatory framework has been in place.[6] (Emphasis added)

In addition, *S&P* states that,

> Standard & Poor's evaluation of regulation also encompasses the administrative, judicial, and legislative processes involved in local or national regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, environmental and safety rules, facility siting, and securities sales… Standard & Poor's ratings factor in the impact of such constraints and obligations on a utility's operations and financial performance.[7]

S&P speaks credibly on behalf of the capital markets, and these statements underscore the key role of capital attraction in setting fair and reasonable tariffs.

Q. What is the amount of capital construction by investor-owned utilities in the U.S.?

A. The amount of capital investment by investor-owned utilities from 2000 to 2004 in the U.S. was $195 billion.[8] Such a figure illustrates the magnitude of the financial needs to support the utility infrastructure in the U.S. and the importance of the regulatory compact in supporting such investments.

2. Legal Supports for the Regulatory Compact: "*Bluefield*" and "*Hope*"

Q. What legal precedent exists for investor owned utilities ability to attract capital?

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[6] Cheryl E. Richer, "Rating Methodology for Global Power Utilities," Standard & Poor's Infrastructure Finance, September 1998, p. 65.

[7] *Id.*, p. 66.

[8] "2003 Financial Review Plus 2004 Developments: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry," (Washington, D.C.: *Edison Electric Institute*, 2003), p. 27.

A. The United States Supreme Court established the traditional standard for a fair and reasonable return in its *Hope* decision (*Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)):

> …the return to the equity owner should be *commensurate with returns on investments in other enterprises having corresponding risks*. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to *maintain its credit and attract capital*. (Emphasis added.)

This often-quoted passage from the *Hope* decision, besides providing a legal standard for determining the fair rate of return, comports precisely with the opportunity cost standard for determining the fair rate of return that covers the utility's cost of capital.

In an earlier case, *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679, 693 (1923), the Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.

Finally, the Supreme Court stated in *Bluefield* that establishing an insufficient return on invested capital denies shareholders the Constitutional right of due process under the Fourteenth Amendment.

> Rates, which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being so used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment.

These two Supreme Court decisions in the U.S. have defined expectations for investments in U.S. public utilities to this day—indeed, they are generally referenced as the basis for determining the fair return to utility investors in modern rate cases.

3. Capital Attraction Is Not an "Academic" Exercise: PGE Spent $180 Million per Year on Capital Expenditures During the mid- to late- 1990s

Q. Would violating the regulatory compact harm ratepayers?

A. Yes. The regulatory compact exists to allow utilities to attract capital economically by giving investors the assurance that as long as the utility acts prudently and serves the public well, their investments will be repaid. As such, a violation of the regulatory compact would harm customers either by driving up the utility's costs of securing investment funds or, ultimately, in driving away investors and preventing utilities from having the ability to render uninterrupted service.

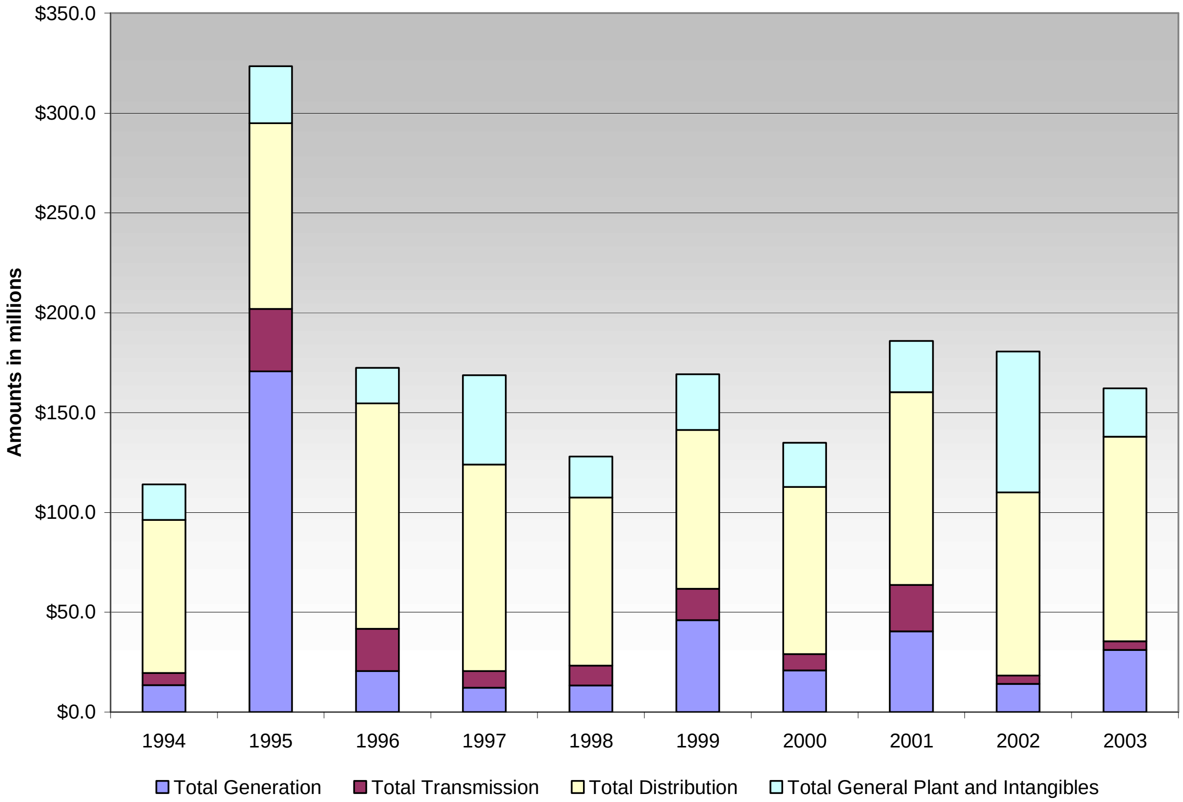
Q. Is this a relevant question for PGE?

A. Yes. PGE requires investment funds to pay for capital expenditures in new power plants, transmission and distribution lines, and the replacement/renewal of existing systems. This ongoing capital expenditure is required for PGE to continue to provide safe, adequate and reliable service for its customers.

Q. What capital expenditures has PGE faced in recent years?

A. PGE's capital expenditures include generation, distribution, transmission, and general plant and intangible plant expenses. From 1994 to 2003, the vast majority of PGE's utility plant capital expenditures, 82.8 percent, were spent on upgrading or replacing generation, distribution, and transmission facilities that directly impacts the consumer of electricity. The remainder of the capital expenditures was spent to purchase land, structures, office

Figure 1: PGE's Capital Expenditures by Segment (1994-2003)[9]



supplies, communication equipment, and other tools needed to run the utility. Figure 1 details the capital expenditures for PGE from 1994 to 2003.

Q. What financings did PGE undertake during this period?

A. PGE has been active in financing activity from 1994 to 2003, as shown in Figure 2.

[9] Source: FERC Form 1 for PGE 1994-2003.

Figure 2: PGE's Financing Activity by Segment (1994-2003)

Portland General Electric
Financing Activity (in millions) [1]
1994-2003

Year	Capital Expenditures for Utility Plant	Total Capital Expenditures [2]	Total New Financing [3]
1994	$114.0	$221.7	$126.6
1995	$323.4	$211.8	$176.3
1996	$172.4	$186.9	$170.6
1997	$168.8	$188.0	$12.2
1998	$128.1	$165.9	$147.1
1999	$169.2	$226.3	$160.9
2000	$134.9	$182.2	$147.3
2001	$186.0	$211.9	$308.4
2002	$180.7	$180.3	$250.0
2003	$162.1	$187.2	$334.5
1994-2003 Average	$174.0	$196.2	$183.4

[1] Financial Data is from FERC Form 1s.
[2] Total Capital Expenditures includes capital expenditures for utility and non-utility plant, Trojan decommissioning expenses, sales of assets, and +/- change in construction work in progress.
[3] Total New Financing includes new long term debt, short term debt, equity and other financing.

Q. Are good credit ratings important to PGE's ability to support such investments?

A. Yes. With respect to the importance of maintaining credit ratings, PGE states that, "credit ratings reduction would likely have an adverse effect on the Company's ability to issue commercial paper and increase the cost of funding its day-to-day working capital requirements."[10] Without viable and sustained access to the capital markets, PGE's ability to invest in utility generation, transmission, and distribution plant might have been

[10] 2001 SEC Form 10-K for Portland General Electric Co., p. 35.

compromised. At the very least, costs for obtaining those funds for its public service investments would have been considerably greater.

Q. What do you conclude about the role of the regulatory compact?

A. The regulatory compact developed in the U.S.to assure that utility customers would be reliably served by highly capital intensive utilities at the lowest reasonable cost, and that PGE and its customers have continuing needs to attract capital at the lowest reasonable cost. The following two sections of my testimony take the regulatory compact as a point of departure to discuss the following:

1. Section III discusses how that compact has served to confirm utility investors' expectations regarding the safety of prudent utility investments in other states—even when nuclear power plants like Trojan were retired before the end of their projected lives.

2. Section IV discusses how an abandonment of the regulatory compact in Oregon—through one interpretation of Oregon law—would separate the State in the minds of investors from the rest of the U.S. and drive up investment risk and costs to serve Oregon ratepayers.

III. Nuclear Power Plant Construction, Operation and Retirement in Other Jurisdictions

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

A. This section shows how the regulatory compact responds to assets that are highly capital intensive, take years to build, and are sometimes retired before the end of their projected useful lives. I present examples from other jurisdictions to illustrate the general consistency of treatment of nuclear power plant costs—expectations that were present in Oregon when Trojan was built and when the decision came to close it.

A. The Regulatory Compact and Findings of Imprudence

Q. What is the role of "imprudence" in the regulatory compact?

A. The regulatory compact is a two-way street—reciprocal obligations on both investor-owned utilities and regulators. If the utility does not serve all ratepayers with safe, adequate and reliable service at the lowest reasonable cost, then a regulator may have cause for a disallowance of all or part of an investment based on a finding of "imprudence." These findings are specific to particular expenditures and circumstances.

Q. How do regulators evaluate the prudence of decisions and actions by utilities relating to their generation assets.

A. From initial planning and development to operation and maintenance—and ultimately retirement and decommissioning—regulators evaluate prudence in virtually all the activities relating to generation assets.

The process begins at the planning stage. Before a project is developed, utilities must obtain approvals from local, state and federal agencies. Once the project is developed the regulator also evaluates the costs of the project the next time the owner is involved in a rate case. At this point, the regulator determines which costs relating to the project can be recovered and/or added to the "rate base" so that a return on capital can be collected from ratepayers over the life of the plant.

Once a plant is placed into service and its costs are approved and added to the rate base, the regulator has explicitly endorsed the investment as a prudent investment. From that moment, future actions relating to operation, maintenance and management of the project can also be scrutinized in additional rate reviews and audits by state and federal agencies.

Finally, regulators can express their approval or disapproval of the decision to retire or continue operating plants. Utilities can conduct specific studies that provide analysis to inform these decisions, or they can include this analysis in an Integrated Resource Plan (IRP), which is a comprehensive evaluation of the least cost way of meeting future energy demand. As we discuss later in this section, an IRP conducted by PGE and reviewed by the regulators demonstrated that the expected benefit of continuing to operate Trojan to be negative (or stated differently, there was a positive customer benefit to close Trojan.) The regulator used this study to determine that early closure of Trojan was prudent.

B. How the Regulatory Compact Has Been Applied in Cases Involving the Early Retirement of Nuclear Plants

Q. Have regulators in other jurisdictions been clear about whether early retirement of nuclear plants justified a disallowance?

A. Yes. In other jurisdictions, regulators have been clear that disallowances should be applied only when there is imprudence and not simply because a plant was retired early for prudent economic reasons. The following enumerates cases where nuclear plants were retired early and describes how regulators dealt with the recovery of and on the unamortized portions of those plants.

1. Connecticut Yankee

Based on a 1996 Continued Unit Operation study, which concluded that under several different scenarios replacement power costs were less than the costs of continuing to operate the plant, the owner-purchasers of Connecticut Yankee Atomic Power Company (Connecticut Yankee) voted unanimously to retire the plant. Several other interested parties, including the Connecticut Office of Consumer Counsel (COCC), contested Connecticut Yankee's decision before the Federal Energy Regulatory Commission.

In its Opinion and Order Affirming the Initial Decision, the FERC stressed the implications of the regulatory compact as stated in the Initial Decision. The FERC explained that the ALJ in his Initial Decision found that Connecticut Yankee management of the plant was imprudent. But as an alternative, in case the FERC did not agree with his finding of imprudence, the ALJ recommended a return on and a return of the undepreciated balance in Connecticut Yankee:

> In the event that the Commission did find that Connecticut Yankee had acted prudently and was thus entitled to a return on equity, the judge adopted the trial staff's proposed return on equity of 8.63 percent to reflect that Connecticut Yankee's risks had been reduced following shutdown.[11]

Between the Initial Decision and the FERC ruling, Connecticut Yankee settled for full recovery of the unamortized portion of its nuclear plant at a lower rate of return.[12] In the Opinion and Order Affirming the Initial Decision, the remaining issue confronting the FERC was the COCC's interpretation of language in amendments to the basic contracts to

[11] Connecticut Yankee Atomic Power Co., Docket ER97-913-000, Opinion 449, 92 FERC ¶ 61,269 at 61,898 .(Sept. 28, 2000)

[12] Id at 61,899.

purchase power from the plant. COCC claimed the amendments disallowed Connecticut Yankee from collecting all costs other than decommissioning costs. The judge and the FERC both agreed that the proper standard for evaluating the contract provisions was the just and reasonable standard. Regarding the amendments the Commission stated that:

> We affirm the judge's finding that the proper standard for evaluating the proposed amendments contained in the 1996 Agreements between Connecticut Yankee and each of its ten purchasers is the just and reasonable standard. No exceptions were taken to this finding.[13]

And,

> Although the judge acknowledged the deleted language "is understandably susceptible to the construction suggested by the interveners," we find that the judge properly determined, on the basis of other provisions in the contracts, that this language was not intended to relieve owner-purchasers of other legitimate obligations that remain to be paid after the shutdown.[14]

Thus, the judge and Commission both affirmed that the basic logic and value of the regulatory compact should supersede when possible interpretations go against the economic principles that are essential to this compact.

2. Maine Yankee

In a similar case to Connecticut Yankee, the Maine Yankee nuclear plant was shut down for economic reasons in 1997. The nuclear facility faced increasing operation and maintenance expenses as well as looming capital expenditures to keep the plant operating. It was disputed that imprudence was a factor for the early retirement of the plant.[15] Given that it was arguable that economic reasons (beyond Maine Yankees' control) and some imprudent management both contributed to the early retirement of Maine Yankee, a

[13] Id at 61,901.

[14] Id.

[15] Before the FERC, Maine Yankee Atomic Power Co. Docket ER98-570-000, "Commission Trial Staff's Comments In Support of Offer of Settlement," Filed January 19, 1999, p. 6.

settlement was reached that involved a lower rate of return than the one originally requested by Maine Yankee. [16] The full undepreciated investment in Main Yankee was recovered at this rate of return. Thus, Maine Yankee provides another example where the early retirement of a nuclear plant was evaluated to carefully discern between economic reasons beyond the control of the plant owner and varying degrees of imprudence.

3. Millstone 1 – WMECO (Massachusetts)

Another nuclear plant that was shut down early in part for economic reasons was Millstone 1, primarily owned by Western Massachusetts Electric Company. Similar to the Connecticut Yankee case, it was also claimed that reasons relating to imprudence played a role in the early retirement of Millstone 1.[17] The consideration of the regulatory treatment for Millstone 1 was complicated by the need to analyze the plant shutdown under the recently enacted Massachusetts restructuring law. However, both the Massachusetts Attorney General and the Massachusetts Department of Telecommunications and Energy (MDTE) were careful to explain that, under the new law, shutting down the plant early solely for economic reasons was in the public's interest and thus would not have created justification for any disallowance. This explanation was first provided by the Massachusetts Attorney General and later cited by the MDTE. In an order issued by the MDTE, it recalled the following:

[16] This settlement was uncontested. 87 FERC ¶ 61,252 (June 1, 1999)

[17] Massachusetts Department of Telecommunications and Energy, Order for Docket D.T.E. 97-120; Re: "Petition of Western Massachusetts Electric Company pursuant to General Laws Chapter 164, Sections 76, 94 and 220 C.M.R et. seq., for review of its electric industry restructuring proposal." p. 23.

> The Attorney General contends that in order for a company to be entitled to a full stranded cost recovery, it must have demonstrated that its generation–related assets became uneconomic due to competition.[18]

In that same Order, the MDTE states that:

> In order to allow transition cost recovery, the Department must determine whether the Company's decision to retire the plant was based upon an analysis that the plant was uneconomic due to the creation of a competitive generation market.[19]

Ultimately, the MDTE determined that the plant had been shut down in part due to imprudent actions. Nonetheless, the standard set by the Massachusetts regulators in the Millstone case provides another example where the decision to allow recovery, including a return on the unamortized portion of the plant, was based on whether the plant was shut down solely for economic reasons and not for reasons of imprudence.

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[18] Massachusetts Department of Telecommunications and Energy, Order for Docket D.T.E. 97-120; Re: "Petition of Western Massachusetts Electric Company pursuant to General Laws Chapter 164, Sections 76, 94 and 220 C.M.R et. seq., for review of its electric industry restructuring proposal." p. 23.

[19] Massachusetts Department of Telecommunications and Energy, Order for Docket D.T.E. 97-120; Re: "Petition of Western Massachusetts Electric Company pursuant to General Laws Chapter 164, Sections 76, 94 and 220 C.M.R et. seq., for review of its electric industry restructuring proposal." p. 25.

IV. The Case For Trojan: Implications Of The Regulatory Compact

Q. What are the basic implications of the regulatory compact and its applications with respect to Trojan?

A. In Section II, I explained that the regulatory compact is more than a set of principles, it is essential to the solvency of regulated businesses like PGE. This is because PGE and other electric utilities are capital intensive. Without access to low cost capital, companies cannot remain solvent. However, without a sound and credible regulatory compact, lenders and investors are not willing to offer their capital at a low cost.

Section III demonstrates how important the regulatory compact is perceived in other jurisdictions. Dealing with all the unexpected costs, including the stranded costs associated with nuclear assets has been difficult for the industry and has tested the viability, credibility and rigor of the regulatory compact. Notwithstanding this challenge, regulators have generally approached each case with deliberate review processes and consistent actions based on sound regulatory principles.

The examples in Section III demonstrate the ability and willingness of regulators in other jurisdictions to discern between costs relating to the imprudence of management versus costs resulting from events that management cannot reasonably control. The examples also clearly illustrate that events leading to the early retirement of nuclear plants can result from either or both of these reasons. Regulators examine each case based on its individual characteristics and apply resolutions that are just and reasonable. Regulators do not excuse ratepayers from legitimate obligations simply due to a single case where the legal language is susceptible to that interpretation. Rather, it is the spirit of what is just and reasonable that guides the decisions of judges and Commissions in these situations. The case of Connecticut Yankee made that clear.

Given these principles and their application in other jurisdictions, the implications for Trojan are that investors had a clear expectation, consistent with regulatory principles in the U.S.generally, that they would be entitled to the recovery of the prudent costs relating to Trojan. If PGE did its part in cooperating with the regulator as required under the regulatory compact, then there is no economic basis to reverse decisions made by the regulator at the expense of PGE and it shareholders. Moreover, such actions could also harm ratepayers.

Q. Did PGE's Oregon regulators uphold the regulatory compact in its decisions related to the closure of Trojan?

A. Yes. A review of the interactions between PGE and its regulator reveals that the regulatory compact did function well and PGE did cooperate with the regulator. The regulator in Oregon had sufficient opportunity to judge the prudence of PGE with respect to Trojan and when it found imprudence, the regulator responded with appropriate actions. I summarize this process in the remainder of this section of my testimony.

Q. How did the regulators in Oregon make determinations regarding the prudence of costs incurred due to Trojan at all these possible stages, including planning, development, start-up operation and retirement?

A. In Oregon as in other states, a thorough regulatory process such as the one described above is used to determine the prudence of actions relating to large power plants such as the Trojan facility.

According to Moody's, PGE began obtaining necessary authorizations to build Trojan as early as 1969.[20] By the time Trojan went into service in 1976, PGE had obtained all the necessary approvals required by the NRC and other state and federal agencies.

During the years Trojan was in service, its operation, maintenance and management were carefully scrutinized during several rate cases and by both state and federal agencies. Several orders and opinions regarding rate issues were issued by the Oregon Public Utility Commission (OPUC) while Trojan was in service.[21] These cases provide several examples of the regulator's opportunities to evaluate the prudence of actions taken by PGE in relation to Trojan.

In addition to the opportunities to examine PGE's prudence in rate cases, the regulator also had the opportunity to review PGE's overall supply plan as described in its IRP. PGE published its second IRP in 1992. This IRP was updated in early 1993. The updated IRP showed that the costs of continued operation of the Trojan plant exceeded its benefits to customers. The Commission agreed with PGE's assessment of Trojan and authorized its closure. Thus, the decision to close Trojan was also subject to regulatory review.

In OPUC Order 95-322 (Docket No. UE 88), the commission dealt specifically with the prudence of the undepreciated investment and other costs associated with the early retirement of Trojan. The OPUC had the opportunity to determine if there was any imprudence on PGE's part and did in fact require PGE equity investors to bear a portion of these costs. Specifically, the OPUC disallowed certain costs related to plugging and sleeving as well a spare reactor coolent pump. Thus, it is clear that the Oregon regulator

[20] Moody's Public Utility Manual, 1970, p. 503.

[21] These included Dockets UF 3796, UE 47, UE 48 and UE 79

was playing its role in discerning between imprudent costs and costs that resulted from events beyond PGE's control. This is precisely analogous to the actions of regulators in other jurisdictions, which I discussed previously in this section.

Q. Was PGE an exception in its decision to retire Trojan due to economic reasons?

A. No. The landscape for nuclear generation changed in the generation industry from the 1970s to the 1990s. During the 1970s, the U.S. as a whole desired to reduce its dependence on fossil fuels due to high prices and geo-political uncertainty. By the late 1980s, prices for fossil fuel sources decreased and the operation and maintenance costs for nuclear power were found to be higher than originally anticipated. The industry also introduced the use of Least Cost Planning, also called an "IRP." Although the original pursuit of nuclear power was prudent, and in the interest of ratepayers at the time, the economic conditions surrounding nuclear power changed. Like other owners of nuclear generation, PGE ultimately found that the costs of Trojan no longer warranted further investment to keep it operational.

Indeed, regulators throughout the country were encouraging utilities to retire nuclear plants due to rising costs resulting in part from additional costs imposed on nuclear plant owners in the wake of the Three-Mile Island incident. This encouragement involved incentives to retire plants early. For example, in the case of SONGS-1 in California, and Trojan, the U.S.Office of Technology Assessment states that:

> State regulators' treatment of capital recovery in early retirement decisions for SONGS-1 and Trojan plants were intended to "encourage their acquiescence. SONGS-1 was retired in 1993 after 26 years of operation under an agreement between the California Public Utilities Commission (CPUC) Division of Ratepayer Advocates (DRA) and the owners of the unit (Southern California Edison (SCE) and San Diego Gas and Electric Co.). The agreement provided the utilities full recovery of the remaining

> $460 million in capital costs over an accelerated 4-year period rather than the remaining 15 years in the licensed life.[22]

In Trojan's case, the utility specifically examined the value of Trojan in light of other supply alternatives available to PGE. The regulator reviewed and approved the early retirement.

Q. What do you believe were legitimate investor expectations with respect to Trojan?

A. Investors had a clear expectation, consistent with regulatory principles in the U.S. generally, that they would be entitled to the recovery of the prudent costs of construction and to recover prudent levels of operating and maintenance costs. Further, investors had a reasonable expectation that they would be entitled to recover any undepreciated capital costs, including a return on undepreciated balances, if the plant was closed prematurely for economic reasons. Investors were aware that they bore the risk of not recovering certain costs if the operation, maintenance, and capital investments related to Trojan were ruled imprudent.

Q Has the opportunity to recover prudently incurred costs in Oregon provided reasonable incentives for efficient investment in and operation of generation?

A. Yes. It has provided a well-understood set of expectations that allocated risk in a defined fashion and enabled investors to react accordingly. It has also provided an investment framework that is consistent with the nature of generating assets, consistent with the risk in committing capital to such large and market-specific investments as generation plants and has nurtured a competitive wholesale market. This regulatory framework has facilitated an investment in electric generation that is sufficient to provide adequate reliability and to

[22] U.S. Congress, Office of Technology Assessment, *Aging Nuclear Power Plant: Managing Plant Life and Decommissioning, OTA-E-575* (Washington, DC: U.S. Government Printing Office, September 1993), pp. 84.

reduce the dependence of Oregon on fossil fuels as an electric generation fuel through the construction of nuclear generation facilities.

This framework has also encouraged the efficient operation of generation, including nuclear generation, by holding investor's responsible for the prudence of management actions with respect to the construction, operation, and maintenance of generating plants. The regulatory policies of the Commission have been well-articulated and knowable to investors and can be expected to have favorably influenced the cost of capital. As with any regulatory system, risks were shared between customers and investors. This sharing or balancing is an essential feature of regulation that helps reduce the cost of capital and helps avoid the high transaction costs that customers would incur to individually manage risk.

Q. Given that the regulatory review process functioned well with respect to Trojan, is it reasonable to suggest that investors should bear the risk relating to the fact that Trojan became uneconomic?

A. No. Trojan was developed, operated and eventually taken out of service based on prudence requirements and an IRP process, both of which were carefully reviewed by regulators. Ultimately, Trojan was shut down as a result of market and regulatory developments unforeseen at the time the investors and regulators implicitly entered into their regulatory compact with respect to the Trojan investment. Thus, given that PGE's prudence was carefully monitored at every step of the way, subjecting investors to the unforeseen risk that Trojan become uneconomic would significantly alter the terms of the regulatory compact.

V. One Interpretation Of Oregon Law

Q. You have said that an interpretation of Oregon law may well change investor expectations in Oregon going forward. Please explain.

A. PGE and the OPUC worked together to decide that it was in customers' best interests, given what was known at the time, to retire Trojan in 1992 before the end of its projected life. The process by which the Company and the OPUC did this was familiar to utility investors and regulators alike, reflecting early nuclear power plant closures in other states. For investors, the key part of those decisions was a commitment to allow investors to recoup the prudent investment in Trojan by allowing a return of their capital over time with a rate of return on the remaining balance to fairly reflect investors' opportunity cost of capital.

What was unexpected, by either the Company or the OPUC, was that an interpretation of Oregon law by the Oregon Court of Appeals would serve to uphold some parts of the deal to close Trojan (i.e. the return of the undepreciated balance) while rejecting another (*i.e.*, the return on the undepreciated balance to reflect investors opportunity cost of capital). It would be akin to an interpretation of Oregon law that required Oregon banks, from now on, to accept from homeowners only the principal balance on existing mortgages over the original life of the loans, without the associated interest on the remaining balances. That would be an unexpected shock to the banks—which made those loans under under the expecatation of the payment of both principal *and* interest—that would destroy much of the value of those mortgages. The interpretation here is similarly a shock to PGE and its investors that would destroy much of the value of the investment in Trojan.

If this interpretation required PGE to recover its Trojan investment, without a return, over an extended period of time, then it would cause PGE investors to experience both a very large loss of value and signal that the regulatory compact in Oregon does not work for them.

Q. Is this interpretation of Oregon law consistent with the regulatory compact or regulatory practices in other states in the U.S.?

A. No. If an Oregon utility's return of its undepreciated investment can only be returned over an extended period of time, Oregon law is consistent neither with the regulatory compact nor, in my experience or knowledge, with regulatory practices in other states. As confirmed by the examples that I gave in the previous section, investors can reasonably rely on the return of their prudent investments. To the extent that investors in Oregon face a risk that, despite the best practices and intentions of both they and the regulator, that large proportions of investments may not be recouped, Oregon will see two results: (1) it will confront a risk that investors would not face in other U.S. utility regulatory jurisdictions; and (2) decision-making regarding when to retire/replace will shift facilities toward preserving inefficient facilities rather than serving the economic interest of ratepayers.

Q. Please expand on your answer regarding this new risk faced in Oregon.

A. In my experience, having participated in regulatory cases and commented on regulatory practices in the U.S. (and in 20 other countries) over 24 years, the disallowance of prudently-invested capital in Trojan by such means—that is to say, as an after-the-fact surprise to both the utility and its regulator—looks like an expropriation of an investment inconsistent with the regulatory compact. I say expropriation to mean the taking of a large proportion of investors' funds despite the regulatory planning that culminated in the original rate order on closing the plant.

If upheld, such a move in Oregon would cause utility investors, and market analysts like *S&P*, to factor this unusual—and to my experience unprecedented—risk into the price for which they would make funds available in the future. Just like utility investors internationally take into account particular risks for investing in jurisdictions that do not have a long-lived and settled regulatory compact, such a new reality in Oregon would cause investors to require an Oregon-specific risk premium.

As I stated in Section II, utilities must attract capital to the public service from the market—they have no means to compel its provision. Subsequent to a decision that would prevent the recovery of prudent Trojan investments, the OPUC would have to abandon its practice of using financial data from other electric utilities around the country to gauge PGE's cost of capital—as investments in those other jurisdictions would not reflect Oregon-specific risks. The OPUC would also have to examine and rule on particular risk premiums for Oregon utility investments if its rulings were to be held consistent with the longstanding *Hope* and *Bluefield* standards for adequately compensating utilities for the use of investors' funds.

Q. Has the investment community expressed concern about the result of this case and its effect on the ability of PGE to raise capital funds at reasonable costs?

A. Yes. *S&P* has already indicated in a January 2005 report on PGE that the Trojan case could result in a change to PGE's credit rating. Specifically, *S&P* states:

> In 1993, PGE shut down the Trojan nuclear plant as part of its least cost planning process and the OPUC allowed PGE to collect a return on and a majority of its investment in the plant. Lawsuits have been filed seeking to require PGE to refund $260 million of funds collected that represent a return on its investment in Trojan. Proceedings are currently underway both at the Marion County Circuit Court (class action cases) and the OPUC (remand of previous rate cases). Given the uncertainty over the outcome and timing of the proceedings and the likely appeal process,

> Standard & Poor's treats the potential outcome of the lawsuit and rate proceedings as only a contingent liability at this point. Negative financial impact from these proceedings, if any, will be incorporated by Standard & Poor's when determining the appropriateness of PGE's ratings.[23]

Q. Please expand on your prior answer regarding the decision-making process.

A. The PUC participated in a measured decision-making process regarding the possible early retirement of Trojan, and ultimately agreed to its closure, because it concluded that ratepayers' best interests were served in the process. Vital to this decision-making process was a willing and collaborative interaction between PGE (which had the best information about the possible cost of continuing to run Trojan and the cost of replacing that plant's electricity) the OPUC and the other stakeholders. If the current interpretations of Oregon law can upset such careful planning, then both the Company and the OPUC would now be on notice that there are other factors—other than customers' interests—that must bear on plant-closure decisions. Indeed, if PGE and the OPUC had perceived that this interpretation was likely, it would have affected both the decision to close Trojan and/or the decision on the timing of the repayment of investors' capital.

Q. Regarding the risk premium in Oregon, did you measure the premium that would be required under the Court of Appeals interpretation of Oregon law?

A. No. Patrick Hager of PGE has performed such an analysis supported by Professors Blaydon and Hess.

[23] Standard & Poor's Report on PGE January 26th, 2005.

VI. Conclusions

Q. What is your conclusion?

A. Investors expect investments in U.S.utilities to be made under the regulatory compact. That is:

> First, in return for a monopoly franchise, utilities accept an obligation to serve all comers. Second, in return for agreeing to commit capital to the business, utilities are assured a fair opportunity to earn a reasonable return on that capital.[24]

If investors in Oregon utilities must only have their invested capital in early retired plants returned, without interest over a long time, investors will understand the regulatory compact is inapplicable in Oregon. As a result investors will demand a higher return on their Oregon utility investment to compensate them for the greater risk of utility investments in Oregon.

Q. Does this conclude your direct testimony?

A. Yes.

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[24] *Supra Note* 1.

List of Exhibits

PGE Exhibit	**Description**
6501	Witness Qualifications

JEFF D. MAKHOLM
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Dr. Makholm concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries. These issues include the broad categories of pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive rate making, and the unbundling of prices and services. Issues of market definition include assessments of mergers, including the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies and Parliamentary panels abroad.

Dr. Makholm's clients in the United States include privately held utility corporation, public corporations and government agencies. Focusing mainly in the areas of gas and electric utilities, he has represented dozens of gas distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas producers. Dr. Makholm has also worked with many leading law firms engaged in natural gas and electricity issues.

Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal— many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

Dr. Makholm is Co-Chair of NERA's Energy Practice.

I. Introduction

Q. Please state your name, occupation and business address.

A. My name is Colin C. Blaydon. I am Dean Emeritus and the William and Josephine Buchanan Professor of Management at the Tuck School of Business. My business address is the Tuck School of Business, 100 Tuck Hall, Dartmouth College, Hanover, NH 03755. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. I have been asked by Portland General Electric Company (PGE) to opine on the reasonableness of PGE's proposed allowed rate of return on equity capital given a regulatory environment in which PGE cannot recover a return on any undepreciated investment balance of a plant that is retired early to achieve the least cost outcome for customers.

Q. Please summarize the conclusions you reach in your testimony.

A. I conclude that the Court of Appeals' interpretation, disallowing any return on the undepreciated balance of a utility plant that is retired for economic reasons, increases the required rate of return that investors demand for investing in the Oregon utilities. Given the uniqueness of this new regulatory regime in the U.S., investors are likely to view Oregon utilities as above average risks relative to other utilities elsewhere in the U.S. Based on my analysis, PGE's proposed return on equity (ROE) of 13.1%[1] is reasonable because it falls within the range of estimated ROEs for electric utilities with above average returns. Additionally, the new regulatory regime in Oregon is likely to hurt the debt ratings of Oregon utilities, increasing their cost of debt.

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[1] I consider only the ROE suggested by PGE corresponding to an amortization period of 17 years since this corresponds to a long-run rate of return.

Q. What methodology do you use in applying the financial models to develop an empirical estimate of the required rate of return for equity capital?

A. I evaluate PGE's risk relative to a broad set of 83 other regulated electric Investor Owned Utilities (IOUs) – the set of regulated IOUs employed in the Oregon Public Utility Commission (OPUC) staff analysis for UE-88. For this analysis I used data available in 1994. By conducting an empirical analysis of the cost of equity capital for this set of IOUs, I am able to establish a reliable range of reasonable cost of capital estimates for companies of diverse risk levels. In my analysis, I employ a number of versions of the Dividend Growth Model, a widely used method of empirical finance for determining the cost of equity capital. I perform the analysis using data from credible and well-established sources such as CRSP, Value Line, and Thomson Financial/I/B/E/S, as well as from company SEC form 10-Ks.

II. Analysis of Risk in the Regulated Electricity Industry

Q. What is the cost of capital?

A. The cost of capital is the return that investors require in order to provide their capital to a company. Because a company finances its operations with equity capital and debt capital, the cost of capital can be made up of a mix of equity and debt, where the mix is weighted by the relative amounts of each in the financial structure of the company. The expected return to both debt and equity investors must be sufficient to compensate those investors for the time value of money and the risks associated with the particular investment. Since people prefer to have a dollar today rather than receive a dollar at some time in the future, investors demand compensation for making investment dollars available today. This is known as the time value of money. Likewise, investors demand higher expected returns from companies associated with greater risk. The riskier the company is perceived to be, the greater the likelihood that future cash flows will be much different from what the investors expect today. Given this expectation, they demand compensation for future uncertainty in the present. Investors reduce, or discount, expected future cash flows in order to determine how much they are worth today. The fraction by which investors discount uncertain future cash flows to calculate their present value is known as the discount rate. The greater the risk, the higher the discount rate applied to the expected cash flows from the company. The cost of capital is equivalent to this discount rate – it is the required rate of return that will attract investors to the company.

Q. Can you explain the key sources of risk and how each affects the cost of capital?

A. Risk includes financial as well as market risk. Market risk refers to the fundamental underlying risk of a particular company. This risk arises from factors that affect the revenues and costs and, therefore, the profits of the enterprise. Businesses whose profits are more exposed to the booms and busts of the general economy have higher market risk than firms with less exposure. For example, the computer networking hardware industry likely has more market risk than the electric utility business. This is true no matter how particular companies in each industry are financed because the networking hardware business is more subject to large swings in revenues and profits due to the ebbs and flows of the economy. Electric utility revenues and profits, on the other hand, are much less dependent on the booms and busts of the economy. Variability in utility financial results depends more on such factors as regulatory decisions and the weather (which affects the overall level of electricity demand). Since these variables have little to do with the ups and downs of the economy, electric utilities have less market risk than the more cyclical networking hardware industry. Thus, an important step in determining an appropriate discount rate is estimating the fundamental market risk of the enterprise being valued.

Financial risk arises when companies take on financial obligations such as debt. While both debt holders and equity holders are exposed to business risk, they are affected differently by financial risk. Debt holders have the first claim on cash flows since interest on debt is paid before any dividends may be distributed to equity holders. Similarly, if the assets are liquidated, debt holders are paid first and equity holders receive the remaining funds, if any. As the share of debt increases in the company's capitalization (i.e., financial leverage increases), the returns to equity holders become more variable.

This increase in variability of returns to equity holders is best seen by way of an illustration. If a company performs poorly, absent debt, equity holders receive whatever cash flows the company generates. But if the company takes on debt, payments to debt holders may exhaust cash flows before equity holders receive any. Alternatively, if a company performs exceptionally well, equity holders receive higher returns because debt holders are only eligible for a fixed payment of interest and not a share of the profit. The increase in the variability of returns to equity that results from financial leverage is a source of risk for which equity investors demand compensation. Therefore, an increase in financial leverage will raise the cost of equity, other things being equal.

Q. What types of risk are investors concerned about and how do these relate to the cost of equity capital?

A. Investors are concerned with the total risk associated with a company. The total risk of a company comprises two kinds of risk, non-diversifiable risk, made up of the market and financial risk discussed above, and diversifiable risk:

Total Risk = Diversifiable Risk + Non-diversifiable Risk

Diversifiable risks are risks that are unique to a particular project or firm and that investors can eliminate by holding a diversified portfolio of investments; hence, investors are not compensated for bearing diversifiable risks. When valuing an investment opportunity, diversifiable risks are properly reflected in calculating expected future cash flows, not in the discount rate.[2] Non-diversifiable risk, taking the form of market and financial risk, is the risk that the value of an asset will change in response to changes in the overall market. The cost of equity capital properly will reflect only non-diversifiable risk.

Electric utilities face a wide variety of both diversifiable and non-diversifiable risks. Examples of diversifiable risks include factors such as: operating risks associated with possible technical problems with the plant equipment; demand fluctuations due to unexpected changes in the weather; and impacts on operations and costs resulting from labor strikes. Examples of non-diversifiable risks include factors such as: changes in fuel costs that are correlated with the economy, labor costs, interest rate risks, construction costs, and maintenance costs. All of these costs are correlated with the overall economy. For example, as the economy heats up, more jobs become available, the demand for labor increases and labor becomes more expensive as wage rates rise. Conversely, as the economy slows, fewer jobs are available, unemployment increases, and wage rates fall. The same factors affect the costs for materials and for equipment.

Some risk factors may have elements of both diversifiable and non-diversifiable risk. Importantly, to the extent any of the risk factors facing an electric utility are associated with fluctuations in the economy, these risk factors are non-diversifiable and would impact the required return on equity demanded by investors.

Q. Using these financial principles, what opinions do you have regarding the relative risks in the electricity industry?

[2] That is, given a 25% probability of a negative event such as a mechanical breakdown causing cash flows of zero, an investor would adjust the cash flows by a factor of 0.75 to get the expected value of the cash flows. The investor would then discount this adjusted, or expected, cash flow by the cost of equity.

A. In PGE Exhibit 6602, I show a security market line, which embodies the fundamental relationship between risk and return. As the risk of an asset increases, the return required by investors rises as well. For illustrative purposes, the exhibit ranks the relative risk of various assets by placing riskier assets further to the right on the x-axis. U.S. Treasury bills ("T-bills") are widely regarded as the safest investment available in the capital markets, and are commonly referred to as risk-free assets. The likelihood of the U.S. Government defaulting on these instruments is viewed as extremely low, and because of their short-term maturity (less than one year) they are less susceptible to the inflationary risks that are commonly associated with long-term government bonds. In addition, long-term government bonds also contain a "term premium" over T-bills. This term premium is the extra compensation investors demand for the risks associated with tying up their money over a longer time horizon. Corporate bonds are found to the right of U.S. Treasury bonds because shifting to corporate bonds subjects investors to additional market and default risk, adding to the required return necessary to attract capital. Investment in common stock (equity) carries the additional risks associated with the particular business and how its profits fluctuate with the overall economy. As such, common stock (equity) investments are higher on the risk scale, requiring a higher rate of return, and implicitly a higher cost of capital.

Q. What is the relevance of the cost of capital in rate regulation?

A. Rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. At the same time, an expected return below the cost of capital shortchanges investors. In the long run, an inadequate return denies the company the ability to attract capital, to maintain its financial integrity, and to earn a return commensurate with that on other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the economic issues an inadequate return raises for them. In the short run, deviations of the expected rate of return from the cost of capital create a “zero-sum game”—investors gain if the rate is too high, and customers gain if investors are shortchanged. In the long run, however, inadequate returns are likely to cost customers—and society generally—far more than is gained in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. The costs of an undercapitalized industry can be far greater than the gains from short-run shortfalls from the cost of capital. Moreover, in capital-intensive industries (such as PGE’s regulated electric operations), systems that take a long time to decay cannot be fixed overnight. Thus, it is in the customers’ interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that it does not fall short of the cost of capital, either.

Of course, the cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital even if the allowed rate of return exactly equals the cost of capital. However, a commission that on average sets rates so investors expect to earn the cost of capital treats both customers and investors fairly, and acts in the long-run interests of both groups.

III. Analysis of the Cost of Capital

Q. What are the financial models typically employed in estimating the cost of equity for a company?

A. A variety of financial models are used in estimating the cost of equity. The most commonly used financial models in estimating the cost of equity in the electric utility industry include the Capital Asset Pricing Model (CAPM) and the Dividend Growth Model (DGM).

Q. Please explain the CAPM model.

A. The CAPM is a model of expected returns built on the notion that since investment risk can be reduced by diversification, investors are only compensated for assuming non-diversifiable risks. Specifically, the CAPM holds that the expected return, and hence cost of equity for a company, is described by the following equation:

Cost of Equity = Risk-Free Rate + Beta x Market Risk Premium

Where: “Beta” is a measure of the relative risk of the asset to the overall market

Q. Please explain the DGM model.

A. The DGM is a form of discounted cash flow analysis whereby equity value can be calculated by discounting to the present all expected dividends over some forecast horizon plus any residual value of equity at the end of the forecast horizon. Conversely, the DGM allows one to calculate the implied discount rate, or cost of equity, used by investors if the other inputs are known. The model can be readily applied to the common stock of some IOUs because these companies have a long history of dividend payments and usually a relatively stable rate of increase in dividends over time.

Q. Did you use the CAPM approach to calculate the cost of equity?

A. I did not use the CAPM approach in my analysis as I have found from prior research that, at times, the CAPM approach will yield unreasonably low betas given the characteristics of the electric utility industry. Since beta estimates figure heavily in the CAPM cost of capital calculation as a determination of individual company risk, I have not utilized this approach for the current proceeding. Therefore, I have used the traditional DGM model as the most appropriate estimate of the cost of equity.

Q. Please describe more specifically the DGM approach.

A. At the most general level, the DGM takes the following form:

$$SP_0 = \frac{DIV_1}{(1+r)^1} + \frac{DIV_2}{(1+r)^2} + \ldots + \frac{DIV_t}{(1+r)^t} + \frac{SP_t}{(1+r)^t} \qquad (1)$$

where: SP_0 = current stock price

SP_t = expected future stock price at time t

$DIV_1, \ldots, DIV_t$ = expected dividends at times 1, …, t

r = investors' expected rate of return, or the cost of equity

As equation (1) shows, today's stock price reflects future benefits to investors (dividends and stock price at a future date) and investors' expected rate of return. As I explained in Section II, the cost of equity for a company is equal to investors' expected return on the company's common stock. The DGM thus allows us to calculate the cost of equity using the following known inputs: the current stock price, the expected amount of future dividends up to time *t*, and the expected future stock price at time *t*.

Equation (1) is simplified if we assume that expected future dividends grow at a constant rate (g) in perpetuity:

$$SP_0 = \frac{DIV_1}{(r - g)}$$

where: g = investors' expected long-term rate of growth in dividends per share.

Under the assumption of constant growth, the cost of equity can be solved for as follows:

$$r = \frac{DIV_1}{SP_0} + g$$

The assumption that dividends grow at a constant rate forever is rather simplistic and may not accurately reflect investors' expectations. A somewhat less restrictive approach, the variable-growth DGM, distinguishes between the short-term growth rate and the long-term growth rate. There are a number of ways to implement the variable-growth DGM depending on the number of growth rate forecasts available and the time period covered by such forecasts. Unfortunately, there are no clear theoretical guidelines to dictate which form of the DGM should be used. This is why I estimated the cost of equity for IOUs using six alternative approaches.[3]

Q. For what set of companies did you estimate the DGM model?

A. For this analysis, I calculated the cost of equity for the same sample of 83 companies used by the OPUC staff in the UE-88 proceedings. Such a broad set of companies spans a wide range of risk levels allowing for a better assessment of the effect of the

[3] For further discussion of these six approaches to variable-growth DGM, see Stewart C. Myers and Lynda S. Borucki. "Discounted Cash Flow Estimates of the Cost of Equity Capital – A Case Study," *Financial Markets, Institutions & Instruments* 3, no. 3 (August 1994): 9-45.

change in risk due to the change in regulatory climate resulting from the preclusion of a return on the undepreciated Trojan balance.

Q. Are there any significant additional risks faced by PGE that the companies in your sample do not face?

A. Yes. I understand that Oregon is the only state that does not allow the previously authorized rate of return on the undepreciated balance of an investment retired early for economic reasons. As utilities typically operate one or more plants which have investment balances that comprise a substantial portion of the rate base, the additional risk of not having a return on the undepreciated investment balance disallowed is significant.

Q. How do these additional risks affect your estimate of PGE's cost of equity?

A. As I discussed above, investors demand compensation only for non-diversifiable risk. Thus, only non-diversifiable risks appropriately affect the cost of equity. Since the decision to retire a plant early for economic reasons is based on a wide range of factors such as the cost to build new generation, the efficiency of new generation, and demand for new generation, all of which are correlated with the U.S. economy, the decision to retire a plant is at least partially non-diversifiable.

As a result of the new regulatory environment in Oregon, utilities operating in the state carry significantly more non-diversifiable risk than typical utility companies operating in other states. Thus, investors will demand an above-average return on equity in order to invest in Oregon utilities relative to other electric utilities that do not face this significant risk factor of future disallowances of the return on undepreciated investments.

A more simplistic explanation of why the investor would demand higher returns can be understood from the investor's own perception of the expected value of the future returns from investments. Additional possibilities of disallowances such as the disallowance of the return on the Trojan investment lower the expected value of future investments. Investors will require a higher cost of capital to maintain a risk-adjusted expected return on equity consistent with the broader U.S. market.

Q. Does the specific disallowance of the return on PGE's undepreciated investment in Trojan have any other effect on the risk associated with PGE?

A. Yes. Assuming PGE must collect its undepreciated balance in the retired plant over 17 years, the immediate financial write-off under FAS 90 of approximately $150 million will have a significant effect on PGE's financial leverage.[4] As discussed above, as the share of debt increases in the company's capitalization, the returns to equity holders become more risky. Thus, the increase in financial leverage caused by the specific disallowance of the undepreciated balance in Trojan will increase the required return on equity demanded by potential investors.

Specifically, the resulting $150 million write-off on equity would have increased PGE's financial leverage ratio[5] from 56.18% to 58.98%.[6] This factor alone would have increased PGE's cost of equity from 11.6% to 11.8%.

Q. What are the results of your empirical analysis of the cost of equity for PGE?

A. The results are shown in PGE Exhibit 6603. These results are based on the 83 companies in the sample employed by the staff in their UE-88 analysis. The DGM

[4] See testimony of Mr. Hager, PGE Exhibit 6400.
[5] Expressed as Total Debt/Total Capital.
[6] See testimony of Mr. Hager, PGE Exhibit 6400.

model generates results ranging from 11.4% to 13.9% for the 75th percentile under these six approaches.

Q. Why do you highlight the 75th percentile rather than the average or median?

A. I highlight the 75th percentile to reflect the additional non-diversifiable risk faced by PGE above and beyond the risks faced by the typical utility in the sample of 83 companies.

Q. Is the ROE figure of 13.1% put forth by Mr. Hager in PGE Exhibit 6400 consistent with the range of estimates given by the DGM model?

A. Yes. Consistent with the additional non-diversifiable risk of future disallowances of the return on an undepreciated investment now present only in Oregon, the relevant comparison is to evaluate PGE's ROE against riskier than average companies in the staff sample. The ROE figure of 13.1% put forth by PGE falls in the middle of the range of the 75th percentile estimate under each approach. Even at the 66th percentile, where fully one-third of the companies have higher calculated ROEs from the six approaches, the figure of 13.1% falls within the range of estimates.

Q. Is a 13.1% cost of equity rate consistent with other authorized ROEs in effect in 1994 for the utilities in the staff's sample?

A. Yes. As shown in PGE Exhibit 6604, authorized ROEs in effect in March 1995 ranged from 10.0 to 16.2%. Thus, the 13.1% cost of equity rate falls well within the range of authorized rates in effect in 1995.

Q. Are there any other negative consequences that Oregon's new regulatory regime will have on regulated utilities?

A. Yes. As discussed above, the introduction of the new regulatory regime and the specific effect on Trojan in 1995 would have forced PGE to take a financial write-off of approximately $150 million. As detailed in the testimony of Mr. Hager, this substantial write-off combined with the loss of the return on the undepreciated balance of PGE's Trojan investment would have led to a significant degradation in key financial ratios monitored by the credit rating agencies such as: EBIT interest coverage; total debt to capital; funds from operations interest coverage; funds from operations to total debt; and net cash flow to capital expenditures. As a result of the degradation in these ratios, PGE could have suffered from credit downgrades and, consequently faced higher future borrowing costs.

Q. Are there any measures the OPUC could undertake to mitigate the negative effect on PGE's credit ratings?

A. Yes. As discussed in the testimony of Mr. Hager, the OPUC could adjust the regulatory capital structure in setting PGE's cost of capital by increasing the proportion of the capital structure represented by equity. The resulting improvement in cash flows from such an adjustment would mitigate the degradation in the five key ratios discussed above.

IV. Qualifications

Q. Please describe your educational background and work experience?

A. I received a B.E.E. from the University of Virginia, and an M.A. and Ph.D. in applied mathematics from Harvard University.

I hold a faculty appointment (Dean Emeritus and William and Josephine Buchanan Professor of Management) at the Tuck School of Business at Dartmouth College. I also am on the board of directors of several companies. My professional and academic experience, education, publications, and directorships are described in more detail in the resume attached as PGE Exhibit 6601. My experience in areas that are directly relevant to the assignment embodied in this report is summarized below.

In my academic career, I have taught finance and quantitative analysis at three universities: Harvard, Duke, and Dartmouth. I have taught courses in corporate governance, private equity investing, and entrepreneurship at Dartmouth, and conducted research at Harvard, Duke, and Dartmouth.

In addition to my teaching and research activities, I have served as Dean of the Tuck School of Business at Dartmouth, Vice Provost for Planning at Duke, and Director of the Institute for Public Policy Studies at Duke. In these capacities, I have been responsible for the academic, financial, and administrative aspects of University programs. I currently hold an academic appointment as the Director of the Tuck Center for Private Equity and Entrepreneurship at Dartmouth, a research and education center I founded. In that position, I advise many new startup enterprises and the venture capital funds that finance them. In my professional activities, I serve on the investment advisory boards of the Arcadia Fund, Merrill Lynch Private Equity Partners, HealthPoint LLC, Altus Capital, and the Borealis Fund, and have served on the boards of five venture capital-funded enterprises. I have been a consultant for 30 years and have consulted to both private and public sector organizations.

I have served on the boards of directors of over 30 organizations. These have included not-for-profits, closely held companies, family-owned companies, and companies in capital-intensive cyclical industries. I have served on the boards of several companies involved in capital-intensive cyclical industries including aerospace, aviation, steel, energy (including an Independent Power Producer), and vehicle manufacturing. I have served on board committees with responsibilities for audit, strategy, capital investing, and governance. As a board member, I have participated in decisions regarding financing and competitive strategy including specific issues such as changes in control, acquisitions, divestiture, and liquidation.

Q. In what areas have you consulted?

A. I have consulted on issues of valuation, governance, planning, and strategy. As a consultant, I have worked extensively with the energy industry and also with companies in the railroad, automotive, steel, and appliance industries. My consulting work has addressed many of the same issues with which I have been involved, including governance structure, executive compensation, and profitability improvement.

Q. Have you testified as an expert witness?

A. Yes. I have served as an expert witness in regulatory, litigation, and legislative matters for a variety of industries. My expert testimony has primarily involved matters of financial economics and governance, including issues such as contract disputes, acquisition and sale of companies or divisions, changes in control and joint venture collaborations in industries including steel, electric and gas utilities, railroads, insurance, and financial services.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
6601	Witness Qualifications
6602	Risk Comparison of Alternative Investments
6603	Summary of Cost of Equity for Investor Owned Utilities
6604	Summary of Authorized Return on Equity for Staff Utility Sample

I. Introduction

Q. Please state your name and qualifications.

A. My name is Alan C. Hess. I am a professor of finance and business economics in the University of Washington Business School. My qualifications appear at the end of this testimony. I have written and consulted extensively in the areas of finance, commercial damages, copyright infringement, and commercial banking.

Q. What is the purpose of your testimony?

A. I provide an analysis of the effects on a regulated utility's cost of capital when it is not able to earn a return on plant and equipment that has been retired prior to the end of the asset's depreciation life. I show the equity risk premium that a rational investor would require to continue investing in a regulated utility whose assets are subject to default risk. Default risk in this case relates to the ability of PGE investors to earn a rate of return on the unamortized investment in Trojan. I discuss why adequate compensation of investor risk is necessary in meeting customers' demands and decommissioning risk and its applicability to utilities is modeled to show that required ROE increases with increased risk.

Q. Can you describe the capital attraction function of a regulated electric utility?

A. Yes. The production and distribution of electricity in a growing economy requires continual maintenance, upgrading, replacement, and enlargement of the plant and equipment that produces and distributes the electricity. An investor-owned public utility finances its ongoing physical plant improvements internally from its operating cash flows, and externally via borrowing and issuing equity.

Q. What is the role of investors in providing investment capital?

A. Investors, who buy the utility's bonds and stocks, are willing to provide funds to the utility only if they expect to receive a return on their financing that compensates them for the rate of return they would have received on an alternative use of their funds that has the same risk as an investment in the utility.

Q. What is the role of a Public Utility Commission (PUC) in capital attraction?

A. Public utility commissions attempt to set the rates that a regulated utility can charge its customers at levels that allows the utility to convince investors that they will be competitively compensated for buying the utility's debt and equity.

Q. What if the PUC does not set rates sufficient to assure investors that they will be competitively compensated?

A. Investors will not provide sufficient financing to the utility for it to have the wherewithal to meet its customers' electricity demands. The opportunity-cost based rate of return that investors expect to receive is the utility's cost of capital.

Q. What tools does a PUC have to determine a fair rate of return for equity investors?

A. There are several financial tools that a PUC could use, such as the Discounted Cash Flow (DCF) or Capital Asset Pricing Model (CAPM). I base my discussion on CAPM because its formulation allows for explicit recognition of factors important to this proceeding. The CAPM formula relates the cost of equity capital, k_e, to the risk free interest rate, r_f, the contribution of the utility's payoff to the risk of a well-diversified portfolio, β, and to the equity risk premium per unit of risk that investors require, λ. The CAPM formula is:

$$k_e = r_f + \beta \cdot \lambda \,. \qquad (1)$$

Q. Please summarize how the CAPM formula works?

A. Investors require compensation equal to the rate they would have earned on a risk free assets, such as a default-free U.S. Treasury security, plus a risk premium that is the product of the utility's risk as measured by its beta, β, times lambda, λ, the risk premium that investors require for each unit of risk they bear.

Q. Does the CAPM formula take into account enterprise default risk?

A. No. The CAPM serves as a framework to discuss the cost of equity capital for an ongoing business. It does not include a component for an abrupt end to the business. The CAPM estimate may be thought of as the expected rate of return to bearing business and financial risk but not default risk.

Q. Does the CAPM assumption of no default risk apply to a regulated utility?

A. This assumption of a going enterprise may not hold for a regulated utility whose revenues are based in part on their capital equipment being in use.

Q. Why is it that the traditional CAPM formula may not apply to a regulated utility?

A. If the utility takes some of its capital stock out of use, it may not be able to charge its customers a rate of return on the decommissioned plant and equipment. In the event of plant and equipment decommissioning, the CAPM-based rate of return that investors expected to receive on their investment in the securities that funded the plant is replaced with a rate of return of zero.

Q. If an equity investor knows he is at risk of not receiving a return on a portion of his investment, how could he be compensated?

A. Before they buy a utility's equities, rational investors should anticipate that the utility may decommission some of its plant and terminate the associated rate of return revenue. If so,

investors will require an extra risk premium before they buy the utility's securities to compensate them for the potential loss of their rate of return. This premium has been formally established for corporate bonds.[1] A similar analysis can be applied to equity.

Q. What investment choices does an equity investor have?

A. An investor has a choice between buying equity in a rate-regulated, investor-owned utility, or in another company or portfolio of companies that has the same risk. If the investor buys shares in another company or companies his expected payoff can be represented using the CAPM as $(1+r_f+\beta\lambda)$. If instead, the investor buys equity in a rate-regulated utility, his expected payoff depends on whether the utility keeps the plant and equipment in use.

Q. Please describe how asset impairment risk can be quantified from an investor perspective.

A. Let p be the probability that the utility will decommission some of its plant and equipment before it has generated sufficient revenues to compensate investors for the opportunity cost of their investment in the utility's securities. If this occurs, investors get back their investment but they do not continue to receive a rate of return on their investment. The expected payoff per dollar invested in the event of plant decommissioning is p.

Q. Please describe the risk premium equity investors require associated with this asset impairment risk.

A. Investors know before they invest that the utility may decommission some of its plant and equipment, which reduces the cash flow it has available to pay to investors. Rational investors require an additional risk premium to compensate them for the reduced cash flow

[1] Darrell Duffie and Kenneth J. Singleton, "Modeling Term Structures of Defaultable Bonds," *The Review of Financial Studies* Special 1999 Vol. 12, No.4, pp. 687-720.

they suffer in the event of decommissioning. Let δ be the decommissioning risk premium. With probability (*1-p)*, the utility will continue to operate the plant and equipment. If the utility does not decommission any of its plant and equipment, the expected return to investors is $(1\text{-}p)(1+rf+\beta\lambda+\delta)$. The cost of capital for the ongoing plant and equipment must be increased by δ to compensate investors for the chance of decommissioning.

Q. What equity return does an investor require where this asset impairment risk exists?

A. The expected payoff to an investor for every dollar invested in the utility's equity is:

$$p \cdot 1 + (1 - p) \cdot (1 + r_f + \beta \cdot \lambda + \delta). \tag{2}$$

In this payoff to equity equation, the one stands for the amount of the investment. A rational investor requires that two investments of equal risk have equal expected rates of return. For the regulated public utility that cannot earn a return on its decommissioned plant and equipment, this equal-rate-of-return condition is

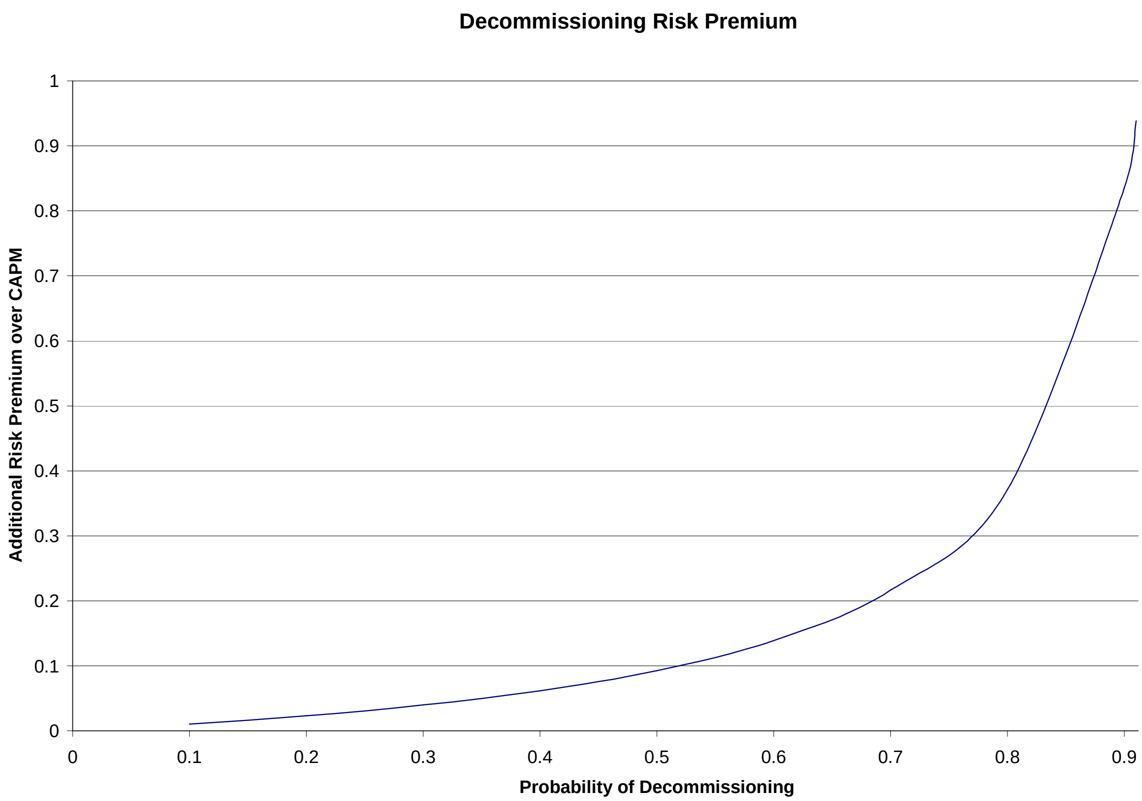
$$1 + r_f + \beta \cdot \lambda = p \cdot 1 + (1 - p) \cdot (1 + r_f + \beta \cdot \lambda + \delta). \tag{3}$$

The left-hand-side is the expected rate of return on an alternative investment with systematic, ongoing risk equal to the systematic, ongoing risk of the utility. The right-hand-side is the expected rate of return on a rate-regulated utility that loses some of its cash flow when it decommissions plant and equipment.

The equal-rate-rate-of-return condition can be rearranged to express the required size of the decommissioning risk premium as:

$$\delta = (1 - p)^{-1}(1 + r_f + \beta \cdot \lambda - p) - (1 + r_f + \beta \cdot \lambda). \tag{4}$$

The decommissioning risk premium depends on the probability that the utility will decommission some of its plant and equipment, the risk-free interest rate, the utility's systematic risk, and the equity premium.



Q. Please give an example of how this risk premium formula can be applied to a utility.

A. The figure above plots the decommissioning risk premium against the probability that the utility will decommission some of its plant and equipment and give up the return on its decommissioned facilities.[2] This figure shows a plot of equation (4) for representative values of the risk-free rate, which is set at 4% in line with the rate on 10-year Treasury bonds in December 2004, a beta of 0.8, an equity premium of 6.6%, which is the difference between

[2] The data in the chart are for illustrative purposes to show how the decommissioning risk premium varies with the probability of decommissioning.

the average annual rate of return on the S&P 500 index and the 10 year Treasury rate for the years 1926-2003, and probabilities of decommissioning ranging from 0.1 to 0.91.

Q. Please describe the implications to a regulated utility and its equity investors of the foregoing graph.

A. Increases in the utility's probability of decommissioning increases the decommissioning risk premium that investors require to own the utility's stock. The only place the investor can look for this expected return is from the utility's cash flows if it keeps the plant and equipment in use. They must receive greater expected cash flows from the utility's ongoing operations to compensate them for the possibility of decreased cash flow in the event of plant and equipment decommissioning. Once the utility decommissions the plant and equipment, its cash flow decreases and it has less money available to pay to its shareholders. As a result, the cost of capital for ongoing plant and equipment is higher for a rate-regulated utility that forfeits the return on its investment in plant and equipment that is not in use.

Q. Please summarize your testimony.

A. The CAPM gives the expected rate of return on an investment in an ongoing business that does not have a truncated return distribution. A rate-regulated utility may not be permitted to earn a return on plant and equipment that is not in use. This truncates its return distribution. To be willing to buy shares in a rate-regulated utility, rational investors require an additional risk premium above the CAPM risk premium. This premium compensates them for the possible loss of future returns from investing in a utility that subsequently decommissions some of its plant and equipment. This decommissioning risk premium depends on the components of the CAPM and the probability that the utility will decommission some of its

plant and equipment. The decommissioning risk premium increases with the probability of decommissioning.

Q Does this conclude your testimony?

A. Yes.

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List of Exhibits

ALAN C. HESS

Alan Hess is an Academic Affiliate of ERS Group and Professor of Finance and Business Economics in the University of Washington Business School. He holds M.S. and Ph.D. degrees in economics from Carnegie Mellon University and a B.S. in industrial management from Purdue University.

Professor Hess's academic and consulting interests encompass both economics and finance. He has conducted studies of:

- Banks, savings and loans, credit unions, insurance companies, factors and investment banks.
- Damages arising from trademark and patent infringement, antitrust, and commercial disputes.
- Event studies of the effects of public announcements on stock prices.
- The valuation of residential and commercial real estate including the effects of alternative financing techniques and environmental restrictions.
- The management of risks using derivative financial instruments including futures and securitized assets.
- The valuation of public utilities.
- The costs and benefits of highway construction projects.

Professor Hess has served in the Federal Reserve System and at the Securities and Exchange Commission. He has won numerous teaching awards including the University of Washington's Distinguished Teaching Award; the M.B.A. Association's Distinguished Professor Award, the Executive MBA Program's Excellence in Teaching Award, the Burlington Northern Distinguished Teaching Award, and the Wells Fargo Outstanding Teaching Award.

EDUCATION

1969	Ph.D. in Economics	Carnegie Mellon University, Pittsburgh, PA
1967	M.S. in Economics	Carnegie Mellon University, Pittsburgh, PA
1963	B.S. in Industrial Management (with distinction, economics honors)	Purdue University, West Lafayette, IN

EMPLOYMENT HISTORY

September 1996 to present	Co-Founder and Principal KeyPoint Consulting LLC, now ERS Group
1967 – present	Assistant, Associate and Professor of Finance and Business Economics , University of Washington
Autumn 1997	Visiting Professor of Finance University of California at Berkeley
Spring 1992	Visiting Scholar, Universidad Nova de Lisboa
Spring 1986	Visiting Professor of Finance Graduate School of Business, University of Chicago
Autumn 1983	Visiting Professor of Finance Graduate School of Business, University of Chicago
Autumn 1982	Visiting Scholar Federal Reserve Bank of Kansas City
Academic year 1977 - 1978	Visiting Associate Professor College of Business, University of Maryland
Academic years 1976 – 1978	Economic Fellow Securities and Exchange Commission, Washington, D.C.
Autumn 1976	Visiting Associate Professor of Economics Virginia Polytechnic Institute and State University
Autumn 1973	Visiting Associate Professor of Economics Department of Economics, University of Virginia
September 1965- August 1967	Economic Fellow Federal Reserve Bank of Cleveland
June 1963 - July 1964	General Electric Computer Department Financial Management

LITIGATION AND BUSINESS CONSULTING EXPERIENCE

ANTITRUST

UltraHue v. Xerox. Analyzed the degree of competition in the market for color laser printers. Assessed whether Xerox has market power in the sale of solid ink sticks. Deposition testimony pursuant to a case filed in United States District Court, Western District of Washington at Seattle.

BANKING AND FINANCIAL INTERMEDIARIES

Served as an expert witness for Recreational Equipment and US Bank in a lawsuit involving an auction sale of a credit card portfolio. Deposition testimony.

Helped defend Associates Financial Services Company against a charge that it violated Montana law in dealing with sub-prime borrowers.

Testified in Guam court about the differences among bank lending agreements, letters of credit, and loan guarantees.

Testified in federal court regarding the nature of and international markets for standby letters of credit.

Advised Bank of America, which was a senior lender on a non-performing loan, on its financial responsibilities to a subordinated lender to the same borrower.

Evaluated the financial performance of KeyBank of Idaho relative to its peers for the purpose of assessing the importance of reducing personnel and occupancy expenses. Deposition testimony.

Testified before the Washington state senate regarding the financial health of WSCUGA, a private credit union insurer, the economic bases for private insurance of credit unions, and the effects of proposed changes in the insurance system on credit union members and the insurer.

Assessed the accuracy of assertions by a dismissed examiner that the Federal Home Loan Bank of Seattle was neglect in its oversight of the risk management activities of a federally insured bank.
Assessed the accuracy of assertions by regulators that Benj. Franklin Savings was taking undue risks before it failed. Examined the effects on risks and returns of regulators requiring the bank to sell offsetting pieces of the derivative portfolio at

different times.

Analyzed the financial effects on First Interstate Bank of Washington of alternative strategies for disposing of a portfolio of mortgages acquired as part of a government assisted takeover of a failed savings bank.

Advised First Interstate Bank of Washington on the incremental cash flows and net present value of a proposed new computer system.

Advised the board of directors of Telco credit union on actions to overcome short-run problems, and recommended changes in performance evaluation and monitoring procedures to improve long-run performance.

Estimated damages to a factor from early termination of a factoring contract by a startup manufacturer. Testified in superior court.

Helped defend the Washington state Director of Banking against a charge that he conspired with a failing bank to deny continued credit to a developer who was in arrears on a loan.

Analyzed the effects of F.I.R.R.E.A on the financial performance of the 5th 3rd Bank.

Analyzed the effects of F.I.R.R.E.A. on the financial performance of Benj. Franklin Savings Bank.

Analyzed the effects of F.I.R.R.E.A. on the financial performance of D&N Bank.

Adviser to Seattle City Employees' Pension Fund. Help evaluate performance, choose asset allocations, and select managers.

COMMERCIAL DAMAGES

ATT v. GTE. Estimated damages to a supplier of business telephone services due to alleged false advertising by a competitor.

Advised a leveraged buyout firm on the price they should pay for a pulp and paper mill. Constructed pro forma financial statements, estimated the cost of capital, and estimated the discounted cash flow value of the company.

Qualcomm v. Ericsson. Estimated damages to a cellular telephone design and manufacturing company due to unfair business practices by a competitor. Included an event study of the effects of each company's product announcements on the other company's stock price.

Strobe Data v. Digital Equipment. Estimated damages to an integrated software and hardware design firm resulting from an alleged breach of contract by a supplier of a critical component. Deposition and testimony in federal court.

Estimated damages to a recycling processor due to a breach of contract by one of its waste suppliers.

Estimated the economic damages to Reinell, a boat manufacturer, of contaminated resin used in the production process. Testified in federal court.

RSR v. AIU Insurance. Helped defend AIU against a charge that its alleged nonpayment of environmental cleanup costs affected the cost of capital of an insured lead recycler.

Analyzed the effects of the stock market and an earthquake on the financial performance of a high-end retail furniture store.

PATENT AND COPYRIGHT INFRINGEMENT

CipherTrust v. IronPort. Evaluated damages to an inbound email appliance company due to alleged trademark infringement. Estimated plaintiff's lost profits, defendant's unjust enrichment, reasonable royalty, and corrective advertising damages. Deposition testimony.

Mackie v. Behringer. Estimated damages to an audio mixer manufacturer from alleged trademark and trade dress infringement. Deposition testimony.

CyberMedia v. Symantec. Estimated damages to a software company from its loss of market share caused by a competitor using many lines of identical code in a widely distributed utility.

Estimated damages to an inventor of medical devices due to alleged patent infringement by St. Jude Medical.

Chamberlin v. Overhead Door. Estimated damages to an electronic garage door opener company due to alleged patent infringement by a competitor.

PUBLIC UTILITY CONSULTING

U.S. West New Vector. Used statistical transfer functions to estimate consumers' demands for cellular service. Paid special attention to estimating price elasticities.

Williams' Gas Pipeline division. Estimated the cost of equity capital, the cash-based rate of return on new projects, the cash-based rate of return on existing projects, the cash-based regulatory rate of return, and economic value added for Williams.

U.S. West. Analyzed the financial consequences of defeasing bonds. Made presentation to board of directors supporting defeasance.

W.I.T.A. v. Pacific County P.U.D. # 2. Analyzed the possible economies to a public utility from being a retail Internet service provider. Deposition testimony.

Built and implemented a discounted cash flow model of public utilities with holdings in the State of Washington for the purpose of assessing their values for *ad valorem* taxes.

REAL ESTATE CONSULTING

Fluke Capital. Analyzed the effects on the city of Bellevue, Washington's tax revenues and convention business of a shortage of hotel rooms due to environmental regulations preventing construction of a city-approved hotel.

SECURITIES LITIGATION

Conducted an event study of the effects of Nortel's earnings announcements on its stock price.

Conducted an event study of the effects of Southeastern Bancorp's earnings announcements on its stock price.

Conducted a "fraud-on-the-market" study of alleged improper conduct by Asia Pulp & Paper.

VALUATION

Analyzed the financial performance of Saber pursuant to a charge that its rates were sufficiently high that it earned monopoly profits.

Reviewed three consultants' valuations of a privately held company. Assessed accuracy of discounted cash flows, capitalized earnings, and adjusted book values.

Reconciled different estimates.

Appraised 50.2% of the stock in a closely held investment company for estate tax purposes.

CONSULTING FOR GOVERNMENTS

Washington State Legislative Transportation Committee. Conducted a cost and benefit analysis of several major transportation projects in a heavily congested section of Seattle beset by traffic conflicts between trucks, trains, cars, bicycles, pedestrians, sports events, port shipping, and ferry traffic.

Bumbershoot. Built a financial model of Bumbershoot, a Seattle city-sponsored festival, from the perspective of making it a stand-alone, private enterprise. Estimated the amount of equity needed to finance the venture.

Estimated the costs to King County, Washington of extra police officer and clerical staff time required by an unfunded mandate from the Washington state legislature governing required police responses to domestic violence calls. Deposition testimony.

Projected changes to state-chartered credit unions' financial performances if the Washington State legislature subjects them to the Business and Occupation tax.

RESEARCH PAPERS

"Are the Major Japanese Banks Uniform or Unique?" With Kathryn Dewenter and Yasushi Hamao. Presented at the NBER/CEPR/CIRJE/EIJS Japan Project Meeting, Tokyo, September 2004.

"Are Relationship and Transactional Banks Different? Evidence from Loan Loss Provisions and Write-Offs." With Kathryn Dewenter. Presented at the Financial Intermediation Research Society conference, Capri, Italy, May 2004. Presented at the European Financial Management Association conference, Basle June 2004.

"Conditional Time-Varying Interest Rate Risk Premium: Evidence from the Treasury Bill Futures Market." With Avraham Kamara. Forthcoming, *Journal of Money, Credit and Banking.*

" Risks and Returns in Relationship and Transactional Banks: Evidence from Banks' Returns in Germany, Japan, the U.K., and the U.S.," (with K. Dewenter), Cambridge University Press, 1999.

"An International Comparison of Banks' Equity Returns," (with K. Dewenter),

Journal of Money, Credit, and Banking, August 1998.

“A Market-Based Risk Classification of Financial Institutions,” (with K. Laisathit), *Journal of Financial Services Research,* December 1997. One of the ten most frequently downloaded papers on the Financial Economics Network.

“Portfolio Theory, Transaction Costs, and the Demand for Time Deposits,” *Journal of Money, Credit, and Banking,* November 1995

“The Term Premium: Default, Liquidity and Interest Rate Risk,” (with A. Kamara), abstract in *Journal of Finance,* Vol. 50, No. 3, July 1995, pp. 979-980

“Do Regulated Utilities Have Growth Opportunities?” *Assessment Journal,* July/August 1995

“Elements of Mortgage Securitization,” (with C. Smith), Reprinted in *Studies in Financial Institutions: Commercial Banks,* C.M. James and C.W. Smith, eds., McGraw-Hill, 1994

“ The Effects of Transaction Costs on Households’ Financial Asset Demands,” *Journal of Money, Credit, and Banking,* August 1991

"Elements of Mortgage Securitization," (with C. Smith), *Journal of Real Estate Finance and Economics,* 1988

"Could Thrifts Be Profitable? Theoretical and Empirical Evidence," *Carnegie-Rochester Conference Series on Public Policy,* Spring 1987

"The Intermediation Profit Margin: A New Measure of Savings and Loan Association Financial Performance," Center for the Study of Banking and Financial Markets *Digest,* Winter 1987

"Size Effects of Seasoned Stock Issues: Empirical Evidence," (with S. Bhagat), *Journal of Business,* October 1986

"Discount Mortgage Financing and Housing Prices," (with P.A. Malatesta), *Housing Finance Review,* Summer 1986

"Comment on Quantification of Selected Elements of Non-Standard Financing which Are Only Partially Capitalized," *Property Tax Journal,* December 1985

"Discount Mortgage Financing and House Prices," (with P.A. Malatesta), Center for the Study of Banking and Financial Markets *Digest,* Winter 1985

"Introduction to Duration," Washington Credit Union League *Investment Guide,* 1984

"Asset and Liability Management Strategies," Center for the Study of Banking and Financial Markets *Digest,* Summer 1984

"Variable Rate Mortgages: Confusion of Means and Ends," *Financial Analysts*

Journal, January/February 1984

"Lease Rates on Washington State Aquatic Lands: Some Economic Considerations," *Western Tax Review,* Fall 1983

Abstract of "Tests for Price Effects of New Issues of Seasoned Securities," (with P. Frost), *The CFA Digest,* Winter 1983

Contribution to *Monetarism and the Federal Reserve's Conduct of Monetary Policy,* Subcommittee on Monetary and Fiscal Policy, Joint Economic Committee, U.S. Congress, December 1982

Review of *Setting National Priorities: The 1982 Budget* and *The Economy: Is this a Change in Direction? Journal of Money, Credit and Ranking,* November 1982

Duration Analysis for Savings and Loan Associations," *Federal Home Loan Bank Board Journal,* October 1982

"Tests for Price Effects of New Issues of Seasoned Securities," (with P. Frost), *Journal of Finance,* March 1982

A Brief History of the School and Graduate School of Business Administration of the University of Washington: The Hanson Years 1964-1981, editor, 1981

"Simulation of Skin Diseases for Teaching Dermatological Diagnosis," (with J.M. Short, M.D.), *Journal of Medical Education,* April 1980

"The Riskless Rate of Interest and the Market Price of Risk: Correction," *Quarterly Journal of Economics,* November 1978

"A Comparison of Automobile Demand Equations," *Econometrica,* April 1977

"Household Response to a Money Rain: Real and Portfolio Balance Effects Reconsidered," *Journal of Monetary Economics,* January 1977

"The Riskless Rate or Interest and the Market Price of Risk," *Quarterly Journal of Economics,* August 1975

"Household Demand for Durable Goods: The Influence of Rates of Return and Wealth," *Review of Economics and Statistics,* February 1973

"Experimental Evidence on Price Formation in Competitive Markets," *Journal of Political Economy,* March/April 1972

"The Money Supply Process," *Journal of Finance,* September 1971

"An Explanation of Short-Run Fluctuations in the Ratio of Currency to Demand Deposits," *Journal of Money, Credit, and Banking,* August 1971

"A Quantity Theory Approach to the Current Inflation," *Washington Business Review,* Summer 1969

"A Note on Supplemental Appropriations in the Federal Budgetary Process," (with G.W. Bowman, O.A. Davis, and H.S. Gailliot), *Papers on Non-Market Decision Making,* January 1967

ACADEMIC TEACHING

Financial markets and institutions
International finance
Banking
Microeconomics
Monetary economics
Macroeconomics

PROFESSIONAL TEACHING

SEAFIRST CORPORATE FINANCE SEMINAR
Present lectures and lead discussion on causes and consequences of interest rate risk; topics include calling and defeasing bonds, swaps, securitization, and monetary and fiscal policies

BANK OF AMERICA, MARKET RISK MANAGEMENT SEMINAR
Present lectures and lead discussion on factors affecting the level and structure of interest rates, duration, and immunization

BOEING COMMERCIAL AIRPLANE CO., SALES FINANCIAL TRAINING SEMINAR
Analysis of the sources of changes in the level and structure of interest rates and their implications for airplane financing

CHASE MANHATTAN BANK, ADVANCED PRODUCT SEMINAR
Present lectures and lead discussion on factors affecting the level and structure of interest rates, duration, and immunization

PACIFIC COAST BANKING SCHOOL
Present lectures to U.S. bankers on the workings of U.S. financial markets, their relationship to economic activity, and their effects on banks' financial performances. Present lectures and lead discussions on managing interest rate and foreign exchange rate risks using forwards, futures, swaps, options, and securitized assets.

BANKING AND SOCIETY IN AMERICA
Teach regional bankers from Japan about the Federal Reserve System and U.S. financial markets

KOREAN BANKERS PROGRAM
Present lectures to Korean bankers covering the structure and working of U.S. financial markets and the Federal Reserve System

MANAGEMENT PROGRAM, SCHOOL OF BUSINESS, UNIVERSITY OF WASHINGTON
Present lectures on monetary and fiscal policy and quantitative analysis of business decisions

SCHOOL OF EXECUTIVE DEVELOPMENT, THE INSTITUTE OF FINANCIAL EDUCATION
Activities include teaching savings and loan association executives the principles of financial management of financial institutions plus administering their playing of the Stanford Bank Management Game

BANK OF CHINA
Present lectures and lead discussions on managing interest rate and foreign exchange rate risks using forwards, futures, swaps, options, and securitized assets.

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July 2004

CERTIFICATE OF SERVICE

I certify that I have this day served the following documents:

- Exhibit No. 6000, Testimony of Pamela G. Lesh;
- Exhibit No. 6100, Testimony of Randy Dahlgren;
- Exhibit No. 6200, Testimony of Jay Tinker, Patrick G. Hager, and Stephen Schue;
- Exhibit No. 6300, Testimony of Stephen M. Quennoz and Leonard ("Pete") S. Peterson;
- Exhibit No. 6400, Testimony of Patrick G. Hager;
- Exhibit No. 6500, Testimony of Jeff D. Makholm;
- Exhibit No. 6600, Testimony of Colin C. Blaydon;
- Exhibit No. 6700, Testimony of Alan C. Hess; and
- Portland General Electric Company Opening Brief,

by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, and by electronic mail pursuant to OAR 860-013-0070, to the OPUC Docket No. UE 88 et al. service list as attached.

Dated this 15th day of February, 2005.

PORTLAND GENERAL ELECTRIC COMPANY

By ________________________________

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February 15, 2005

via MESSENGER and E-Filing

Administrative Hearings Division
Support Unit
Public Utility Commission of Oregon
550 Capitol St., NE, #215
PO Box 2148
Salem OR 97308-2148

Re: In the Matters of OPUC Dockets **UE-88**, **DR-10** and **UM-989**
Testimony and Opening Brief of Portland General Electric Company

Attn: Filing Center

Enclosed for filing in the above-captioned docket are the original and five copies of the following documents:

Exhibit No. 6000, Testimony of Pamela G. Lesh: "Context, Principles, Building Blocks & Recommendation,"

Exhibit No. 6100, Testimony of Randy Dahlgren, "Ratemaking, Trojan History,"

Exhibit No. 6200, Testimony of Jay Tinker, Stephen Schue, and Patrick G. Hager, "Quantitative Analysis,"

Exhibit No. 6300, Testimony of Stephen M. Quennoz and Leonard ("Pete") S. Peterson, and Randy Dahlgren, "Asset Classification,"

Exhibit No. 6400, Testimony of Patrick G. Hager, "Cost of Capital,"

Exhibit No. 6500, Testimony of Jeff D. Makholm, "The Regulatory Compact,"

Exhibit No. 6600, Testimony of Colin C. Blaydon, "Impact on Rate of Return,"

Exhibit No. 6700, Testimony of Alan C. Hess, "The Risk Premium ,"

Opening Brief, and

Certificate of Service with official Service List

These documents are also being filed electronically per the Commission's eFiling policy to the electronic address PUC.FilingCenter@state.or.us, with copies being served on all parties on the service list via U.S. Mail. A xerox copy of the Public Utility Commission tracking information will be forwarded with the hardcopy filing.

PGE has scheduled an informal technical workshop for 1:30 p.m. on Thursday, February 24, in the OPUC Main Hearing Room. At this workshop, PGE will explain its analyses of the different scenarios.

Sincerely,

/s/ Pamela G. Lesh

PGL:lbh

cc: UE 88 Service List

Enclosures

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February 16, 2005

Administrative Hearings Division
Support Unit
Public Utility Commission of Oregon
550 Capitol St., NE, #215
PO Box 2148
Salem OR 97308-2148

Re: In the Matters of OPUC Dockets **UE-88**, **DR-10** and **UM-989**
Testimony and Opening Brief of Portland General Electric Company

Attn: Filing Center

Enclosed is a copy of the Brief with **original signatures** which was inadvertently omitted from the filing of February 15, 2005.

PGE forwarded the above filing by messenger, via US Mail and through the OPUC E-filing address, PUC.FilingCenter@state.or.us. Hard copies were sent to service list parties via U.S. Mail on February 15, 2005.

Sincerely,

Sheila Cox

Enclosure

cc: UE 88 Service List w/o enclosure

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE-88 REMAND

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Pamela G. Lesh
Randy Dahlgren
Jay Tinker
Stephen Schue
Patrick G. Hager
Stephen M. Quennoz
Leonard S. Peterson
Jeff D. Makholm, Ph.D
Colin C. Blaydon, Ph.D
Alan C. Hess Ph.D

Portland General Electric

February 15, 2005

UE-88 REMAND / PGE EXHIBIT / 6000
LESH

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy & Recommendations

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Pamela G. Lesh

February 15, 2005

I. Introduction

Q. Please state your name and qualifications.

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

Q. What is the purpose of this proceeding?

A. This proceeding has its roots in events that began in the early 1990s, shortly after the Commission adopted least cost planning as the process and methods by which Oregon utilities would select the future resources they would use to serve customers. The process the Commission ordered was one of broad inclusion, allowing everyone with an interest the opportunity to understand and provide input on a utility's resource decisions. The method was one of evaluating both supply-side and demand-side resources on a consistent basis and considering both the internal and external costs of resource decisions.

Using the least cost planning process and methods, PGE filed with the Commission in 1992 a plan recommending that we phase out our Trojan generating plant over four years, replacing it with other resources which had a projected lower cost than Trojan. This recommendation had wide support among a large group of participants in our process. When Trojan's condition, and economics, worsened at the end of 1992, PGE quickly analyzed whether immediate closure would increase the benefit to customers over phase-out and, because it did, we closed the plant in January 1993. The Commission ultimately acknowledged both the phase-out and subsequent immediate closure decisions as producing lower costs for customers than continued Trojan operation. Throughout the planning process, PGE assumed that, if closure was the most economic choice for customers, PGE

could recover its remaining investment in Trojan because this sunk cost would exist given either course of action.

Late in 1993, PGE filed a general rate case, UE 88, to adjust our revenue requirement for this significant resource decision. We knew that processing the case would require many months and intended that the rates take effect January 1995. The case's revenue requirement included return of and on PGE's investment in Trojan over the 17 years remaining under the nominal depreciation life the Commission had set for Trojan when it entered service. Filing this way best matched the costs and benefits of the least cost resource decision for customers and did not harm PGE because, as we and the Commission understood Oregon law at the time, the Commission could allow us to recover both return of and on this investment retired to produce economic benefit to customers.

Following the Commission's decision in March 1995, several parties argued to the Oregon courts that Oregon law does not allow return on a utility's investment in a plant it has retired for economic reasons. The Court of Appeals ultimately agreed in 1998 and remanded UE 88 to the Commission. The Oregon Supreme Court accepted the case for further review. In 2000, while that appeal was pending, PGE, CUB and Staff jointly proposed to the Commission, UM 989, a way to eliminate PGE's remaining investment in Trojan, matching this amount owed PGE with a somewhat smaller amount PGE owed customers. The Commission's order approving this proposal was also appealed and, in 2003, remanded to the Commission. Our opening brief discusses both remand orders. The Commission considers the scope of this phase of the process to determine what rates it would have set in UE 88 and whether it would have approved the proposal in UM 989, had it known that Oregon law precluded it from setting rates including a return on investment in

a generating plant retired for economic reasons. If the Commission finds that it would have set lower rates, it will next determine the amount, if any, of refunds to customers. We are engaged here in presenting facts and arguments regarding what the Commission would have done ten and five years ago in UE 88 and UM 989, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present PGE's case regarding the questions this remand proceeding requires the Commission to answer. Relying on the records originally developed in UE 88 and UM 989 and the testimony we file here, I explain what PGE would have urged the Commission to do in the dockets now on remand. What we propose assumes everyone knew throughout the 1990s that Oregon law precludes a Commission from allowing utility investors a return on money invested in a generating plant that is retired because it is more economic for customers to replace the plant's output than for the utility to continue operating it. The prohibition exists even though retirement before the end of the Commission-approved depreciation life produces lower costs for customers than continued operation.

Had the Commission known of this interpretation of Oregon law, it would have had many choices available to it. PGE has identified choices that are consistent with the overarching goal of regulatory policy, that promote analysis and action by utilities to achieve the least cost for customers, that allocate utility costs to customers fairly over time, and that maintain a utility's ability to access capital so that utility service remains safe and adequate. Choices other than those we present here likely exist. But such choices are poor if they do not serve these goals and objectives. Both then – in 1995 and 2000 – and now, choices that do not

serve the goals and objectives of regulation would have resulted and will result in regulation that does not serve customers.

PGE's evidence shows that, had the Commission known of the constraint Oregon law places on its ability to spread the un-depreciated cost of generating plant retired to achieve lower costs:

- In 1995, the Commission would have found fair and reasonable rates at least as high, if not higher, than the rates approved in Docket UE 88, Order No. 95-322; and
- In 2000, the Commission would have approved the stipulation presented to it and the proposed $10 million rate reduction as fair and reasonable and a proper exercise of its discretion in Docket UM 989, Order No. 00-601, because amounts owed PGE at that time would have exceeded the customer credits used as an offset. This would have produced economic as well as other benefits to customers from the resolution of the issues.

I explain the regulatory policy supporting PGE's position and summarize the quantitative analysis underlying it. Our position accepts, for purposes of this policy and quantitative review that the underlying legal theories comply with statutory and constitutional requirements.[1]

Q. How is your testimony organized?

A. My testimony is organized into six sections.

[1] In doing so, PGE is not waiving any legal arguments regarding the availability of refunds for UE 88, UE 93, or UE 100, or the consideration of allegedly "excess" rates in UE 88, UE 93, and UE 100 in the Commission's evaluation of UM 989. Nor is PGE addressing, or waiving, our policy arguments regarding why, even if refunds or adjustment of PGE's balance sheet for past excess rates were legally supportable, such steps would be inadvisable from a regulatory policy perspective and the Commission could exercise its discretion to reject such actions. It is our understanding that we can make our case regarding the advisability of refunds in phase II of this proceeding.

- In Section II, I briefly review the regulatory and ratemaking context for this remand proceeding;
- In Section III, I explain the approach we followed to reach our position;
- In Section IV, I review the reasons for each of the factual or policy decisions from the remanded cases that PGE examined in developing our position;
- In Section V, I explain our position, using the methodology of Section III and certain of the building blocks of Section IV; and
- In Section VI, I summarize the other testimony PGE is presenting.

Q. Are there any explanations necessary with respect to PGE's testimony in this case?

A. Yes, there are two contextual explanations. The first explanation concerns the amount of general ratemaking and background information we are presenting in this docket. Our review of such fundamentals does not imply a belief that the Commission, or the parties, require education in such matters. Indeed, much of it is what any participant in the economic regulation arena learns in his or her first rate case and never consciously thinks about again. But what we "veterans" take for granted, can leave a record that is difficult for a reviewing court to understand. We believe that the unusual nature of these remanded rate determinations requires that we provide a foundation that would not otherwise be necessary.

The second explanation concerns the difference between revenue requirement and rates. The remand orders refer to rates. As the scoping ruling indicates, rates are the result after the Commission determines revenue requirement, allocates that revenue requirement across all of the utility's tariffs (rate spread) and among the billing determinants within each tariff (rate design) and, for those billing determinants based on energy usage, applies the retail load forecast to determine a per kWh rate. For purposes of our quantitative analysis in this

phase, we stop at the first step of this process – revenue requirement – because the remand orders suggest no change in rate spread and design determinations.

II. Regulatory and Ratemaking Context

Q. What is the overarching regulatory policy that guides the Commission in this remand proceeding?

A. All of the Commission's decisions and choices are guided by its delegation of authority from the Legislature, stated in ORS 756.040. That delegation contains two goals that relate to treatment of customers and two that relate to treatment of investors:

Customers

- Adequate service
- Fair and reasonable rates

Investors

- Returns commensurate with the returns on investments in comparable businesses
- Confidence in financial integrity, maintenance of credit and attraction of capital.

The delegation statute requires the Commission to "balance the interests of the utility investor and the consumer in establishing fair and reasonable rates." ORS 756.040. I believe this phrase is somewhat misleading to the extent that one could infer from it an opposition of investor and customer interests, with any gain to investors an equal loss to customers, and vice versa. Rather, the goals for customers and investors are inter-related and reinforcing: A utility cannot provide adequate service without the ability to attract capital. This is typically not in dispute in a rate-setting process.

For example, few would argue that a utility can attract capital if the rates set by the Commission do not allow it to pay the interest on its outstanding debt as such interest becomes due. Indeed, to borrow additional money on reasonable terms requires that a utility have the financial strength – created by the opportunity to earn and retain income over and

above interest payments – to make all future interest payments. Several credit rating agencies exist to inform potential lenders of the likelihood of repayment. The agencies' assessments influence access to and the cost of debt. Borrowing becomes significantly easier and less expensive when a firm has "investment grade" ratings. Accordingly, rate decisions that permit a utility to reach and maintain financial coverage ratios sufficient for investment grade debt ratings are usually not controversial. Above investment grade, however, the Commission must weigh the benefit to customers – in the form of reduced borrowing cost – with the cost to customers – in the form of higher rates today. It is this decision that is the balance between customers and investors.

Q. Is there another "balance" that is an important guide to ratemaking decisions?

A. Yes. The capital intensive nature of the utility business means that many of the costs incurred are large, lumpy expenditures for physical or intangible assets that produce benefits for many years. The Commission is constantly balancing the interests of today's consumer with the interests of tomorrow's consumer. To achieve the best allocation of society's resources over time, someone making the choice to use electricity today should pay roughly what it costs today, not significantly more and not significantly less. The Commission must spread costs fairly across "generations" of customers to achieve this result. It does so most often in the context of setting depreciation rates for all utility property, a task specifically given it by the Legislature. It engages in this balancing for other matters as well, such as amortization and accounting decisions.

This balancing of consumer interests across time relates to the balancing between consumer and investor interests. Rates set too low today to attract capital will make future

capital costs – and, thus, future rates – higher and may cause degradation in future service. Current customers will benefit at the expense of future customers.

Q. Are there any rules regarding how the Commission engages in both balancing investor and consumer interests and balancing consumer interests across time?

A. Very few. The statute at the heart of this remand is one of those few. In general, the Commission has broad discretion to fashion the balances that it finds most suitable to the facts at hand. This excerpt from the UE 88 order is typical:

> "Staff notes that the Commission has broad discretion when it comes to ratemaking. As the Oregon Supreme Court said, 'The [Commission] appears, therefore, to have been granted the broadest authority – commensurate with that of the legislature itself – for the exercise of [its] regulatory function.' *Pacific N.W. Bell v. Sabin*, 21 Or App 200, 214 (1975)." Order No. 95-322 at 61.

The Legislature's – and, thus, the Commission's – authority is constrained only by the Constitution. The seminal case of Federal Power Commission v. Hope National Gas Co., 320 U.S. 591 (1944) explained that the constitutional protections are tested against the end result of a rate order. A later Supreme Court case – Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989) – explained the "end result" test as follows:

> "[I]t is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unreasonable judicial inquiry is at an end. The fact that the method employed to reach that result may contain infirmities is not then important." 488 U.S. at 310

Worth noting is Duquesne's finding that state ratemaking authority cannot "arbitrarily switch back and forth between methodologies in a way which [requires] investors to bear the risk of bad investments at some times while denying them the benefit of good investments at other times" without raising serious constitutional questions. Duquesne, supra, 488 U.S. at 315.

Any exercise of the Commission's broad discretion as it sets rates, within its statutory delegation and subject to the U.S. Constitution's requirements on the end result, will have consequences for the future. The objective of regulatory policy is to find that exercise of discretion the consequences of which move the Commission closer to, not farther away from, its overarching goal of securing adequate utility service for consumers at fair and reasonable rates. To simplify its task, the Commission adopts certain frameworks and conventions.

Q. What do you mean by frameworks?

A. Integrated resource planning (IRP), or least cost planning (LCP) as it was known when the Commission first issued the order adopting it, is an example of a framework - and a very important one to consumers generally and to this proceeding. In 1988, the Commission determined that the process by which a utility chose its generating resources was a critical component of whether the Commission could find rates based on those decisions to be fair and reasonable. In particular, the Commission found that allowing public review of and input to utility resource decisions would improve the quality of such decisions. The Commission acknowledges resource decisions using the IRP framework and such acknowledgements affect subsequent ratemaking decisions. "Although a decision made in the LCP process does not guarantee favorable ratemaking treatment, the process should provide some guidance to a utility." Order No. 89-507 at 3.

Q. What do you mean by "conventions?"

A. By the term "convention," I mean "the way we usually do things unless there is good reason, determined by the Commission's overarching goal, not to." The use of cost as the basis of setting rates is a convention. Nothing requires that the Commission use cost. But it

is hard to think of a basis to use for ratemaking that is easier to determine and understand than cost and, thus, typically, economic regulation relies on cost. The choice of a test period over which to assess costs and revenues for purposes of determining rates is a convention.

Calculating interest costs and equity costs (net income) on the basis of rate base is also a convention. For some water utilities, this does not work at all because the utility plant they use is fully depreciated. In those instances, the Commission does not use rate base to determine the cost of debt and equity for rate-setting. Including purchased power in revenue requirement at the cost of the contract is another convention.

If any of these conventions has consequences that move the Commission further away from its goal of adequate service at fair and reasonable rates, the Commission has the broad discretion – noted above – to change the convention. A good example of this is the policies the Commission adopted in the early 1990s to encourage utilities to acquire demand-side resources – customer energy efficiency measures – to help offset future needs for generation. Mr. Dahlgren, PGE Exhibit 6100, Section II, discusses these policies.

These conventions not only change over time, but there is considerable diversity of conventions across regulatory jurisdictions. How one jurisdiction calculates various costs for ratemaking purpose may differ significantly from the conventions used in another jurisdiction. None of the variations are wrong; they are simply different.

Q. Is there a convention that particularly requires examination in this proceeding?

A. Yes. In Docket DR 10, the Commission developed the convention that it would use in setting rates for a utility that had retired a generating plant to achieve least cost power supplies for its customers. In brief, this convention was that a utility could recover its un-depreciated investment in a generating plant retired prior to the end of its nominal

depreciation life, if it established six facts and met six conditions designed to permit a conclusion that the retirement produced a "net benefit" for customers. Mr. Dahlgren describes the convention in PGE Exhibit 6100, Section III. The Commission applied this convention, with some refinement and further detail, in UE 88. The primary refinement of UE 88 was the conclusion that the net benefits test would consider the costs and benefits of retiring and replacing the output of that generating plant from a ratemaking perspective in addition to a planning perspective. The ratemaking perspective, eliminated from the calculation future costs found to be imprudent.

In developing this convention, the Commission assumed that it could set rates to include a return on any un-depreciated balance of the retired generating plant that the Commission did not allow the utility to recover immediately. The Commission did not contemplate that its decision regarding how to spread the un-depreciated plant costs to customers over time could also result in harm to utility investors. The net benefits calculation did not account for this; nor did the Commission's six conditions. Because of the Court of Appeals ruling, the Commission must develop, and apply, a new convention for the recovery by a utility of its remaining investment in a generating plant that it retires before the end of the plant's original depreciation life to achieve least cost for customers.

Q. How do the "overarching regulatory policy," frameworks and conventions you have discussed relate to PGE's position in this remand proceeding?

A. PGE's position rests on the assumption that, in this remand proceeding, the Commission will exercise its discretion regarding:

- The application of ratemaking conventions,
- Decisions on factual issues, and

- Policy choices

to achieve the overarching goal of regulatory policy and continue to support the frameworks – including IRP – it has developed. According to the Court of Appeals, the Commission may not set rates based on calculations that include return on the un-depreciated investment in an economically-retired plant that is being recovered over time, but the Legislature does not otherwise direct how the Commission should have set rates in UE 88 or UM 989. The overarching regulatory policy set forth in the Commission's delegation of authority applies and the Commission has broad discretion in how it exercises that authority.

Q. Is there anything unique about this proceeding?

A. Yes, the remand nature of this proceeding makes it unique. The Commission is not setting rates that will be in effect in 1995. Nor is it setting rates that will be in effect in 1996, 1997, 1998, 1999, or 2000. Instead, the Commission is engaged in setting rates for periods in which those rates cannot possibly take effect. Neither PGE nor customers can change past decisions that were made on the basis of these rates. The ratemaking decisions the Commission makes here can take effect only in the future. Based on the policy and future rates that emerge from this proceeding, PGE and its customers can only affect future decisions.

III. PGE's Approach

Q. What approach did PGE follow in reaching your position in this remand proceeding?

A. We applied three questions to serve as the criteria by which we could test the regulatory policy strength of our position. Then we identified the factual and policy decisions made in UE 88 that require re-examination in light of the Court of Appeals interpretation of Oregon law. Our position is a set of changes that best meets the criteria.

Any rate decision is the sum of a myriad of interconnected, factual, and policy decisions. It is hard enough to steer such decisions to rates that meet statutory and constitutional tests and produce consequences that work toward achieving the overarching goal of regulatory policy in the future when in a normal general rate proceeding. A retrospective review such as this only increases the difficulty. In such circumstances, developing and applying criteria helps discipline and manage the large number of possible paths.

Q. What criteria did PGE develop for this proceeding?

A. We believe that, had the Commission known in deciding UE 88 and subsequent cases that, if it spread the recovery of Trojan's un-depreciated balance over time, then it could not allow PGE to earn a return on the balance, its factual and policy decisions in UE 88 and ultimately UM 989 would have been guided by the answers to these questions:

1. Does this decision encourage electric utilities to analyze and make resource decisions that will yield "an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"[2]
2. Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears

[2] OPUC Order No. 89-507, page 2.

an inequitable burden of the costs or receives an inequitable share of the benefits?

3. Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

Q. Please explain the first criterion: Whether this decision encourages electric utilities to analyze and make resource decisions that will yield "an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest."

A. First and foremost, this criterion recognizes the importance to Oregon of least cost planning. As Mr. Dahlgren explains, the IRP process is designed to produce least cost resource decisions, over time, for customers. At times, achieving the least cost set of resources for customers may require not only the addition of new resources but the retirement of some existing resources, the incremental costs of which exceed the costs of replacements. The Court of Appeals interpretation has created a barrier to such least cost resource realignments, however. If a utility cannot earn a return on the plant that it has retired to achieve least cost for customers, and the Commission does not allow the utility immediately to recover the remaining plant investment so that the utility's investors remain whole, then it has little incentive to take this resource action. The action would produce negative results for the utility, rather than positive or even neutral results. The disincentive worsens if the Commission does not otherwise set rates to allow a utility in this situation the revenues sufficient to maintain its financial health and credit ratings over time. Oregon utilities would be motivated to continue operating resources for their nominal depreciation lives, rather than their economically useful lives, as measured by least cost to customers over time.

This incentive would work against the least cost planning framework that is so important to achieving safe and adequate service for customers at reasonable rates.

The first criterion also recognizes the soundness of a regulatory approach that encourages utilities to act in the interests of customers and the public, rather than punishing them for not doing so. Mr. Dahlgren discusses an example of such encouragement: the set of policies the Commission adopted to encourage utilities to invest in demand-side resources (energy efficiency). PGE Exhibit 6100, Section II. Instead of adopting these policies, the Commission could simply have told utilities it would disallow any supply-side costs it determined the utility could have avoided by investing in demand-side resources instead. The difficulties with the punitive approach, however, are several. First, it is much easier to identify and reward affirmative actions a utility has taken. Such actions require no speculation. They are measurable. Second, too much use of cost disallowance can threaten a utility's financial integrity and ability to attract capital on reasonable terms, and thus threaten the Commission's ability to achieve the goal of adequate service at fair and reasonable rates in the future. Last, based on my experience observing the effects of regulatory choices over 20 years, rewards can motivate even at the individual level. Rewards encourage individual actions, because individuals can understand how their actions will help the utility achieve better financial results and may be mirrored by individual incentive programs. Utilities cannot so align individual financial results with disallowances.

Q. Please explain the second criterion: Whether this decision equitably allocates the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable burden of the costs or receives an inequitable share of the benefits.

A. This criterion expresses the balance of customer interests I discussed in Section II of my testimony. It is a well-understood principle of economics that consumers will make the best decisions about consumption if the price paid for such consumption at any given time is as close to the true cost as possible. A significant misalignment of costs and benefits of a utility resource decision would violate this economic principle. The Commission routinely applies this criterion in determining the period over which utilities will recover the cost of assets (depreciation or amortization) and expenses (e.g., debt refinancing costs) incurred to produce future benefits, as well as the period over which customers will receive the benefit of utility cost savings (e.g., lower than expected variable power costs) or revenue credits (e.g., sales for resale, property sale gains).

Q. Please explain the third criterion: Whether this decision preserves the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised.

A. As with the first two, this simply states as an explicit question matters I discussed in Section II. Although aspects of this criterion relate to constitutional requirements, it has practical implications for customer needs as well. All investors, debt or equity, care about the regulatory environment into which they are investing. Regulatory policies that are understandable, fair, and focused on the long-term, decrease the perceived investment risk. For example, investors perceive as understandable and fair regulatory policies that allow recovery of prudently-incurred costs. Regulatory policies that put prudently-incurred costs at risk to events or outcomes outside of the utility's control would be perceived the opposite. Decreased risk increases the availability of capital and decreases its cost; increased risk has

the opposite effect. Thus, this criterion is important for investors and customers over time. What appears cheap today may be costly tomorrow.

Q. Are there any other considerations that are important guides to ratemaking decisions?

A. Yes. As a general matter, customers value and Commissions work to achieve rates that are relatively stable over time, with predictable movement. For example, customers typically would prefer a series of small increases, anticipating higher costs over time, than a larger one-time increase. Many consumption decisions relate to equipment or processes that are hard to adjust immediately but that a customer can modify if given some time to do so. For example, assume a large business customer with significant capital investment in equipment and complex manufacturing processes. This customer may be able to reduce its energy consumption over time through changes to equipment, processes or both but it probably cannot make such changes quickly in response to a one-time large increase in the cost of electricity. Spreading such an increase over time in rates that anticipate the higher costs that are coming allows customers to make such equipment and process changes. Achieving rate stability and predictability need not harm customers or the utility as long as the Commission recognizes in setting rates the time value of any rate changes not exactly aligned with the underlying cost changes.

IV. Building Blocks

Q. Please summarize the UE 88 factual and policy decisions PGE is suggesting the Commission might have made differently had it known of the Court of Appeals ruling.

A. The factual and policy decisions we are suggesting the Commission might have made or made differently are the following:

- The period over which it ordered PGE to amortize its un-depreciated Trojan investment (Subsection A);
- The required return on common equity and capital structure (Subsection B);
- The calculation of the net benefits test and application of the resulting net benefit (Subsection C);
- The classification of certain components of Trojan as plant-in-service (Subsection D);
- The amortization period for certain liabilities on PGE's balance sheet owed to customers as of March 1995 (Subsection E);
- The recovery in 1995 of all forecasted 1995 net variable power costs (Subsection F); and
- The inclusion in rates of all of PGE's interest payment costs, regardless of whether the underlying debt relates to un-depreciated Trojan investment (Subsection G).

For each of these factual or policy decisions, I discuss below why the Commission should revisit it, and the outcome or range of outcomes PGE believes the Commission would have adopted and why, including the reasons for changing a ratemaking convention if necessary.

A. Amortization Period

Q. Why should the Commission revisit its decision in UE 88 regarding the period over which PGE should amortize its un-depreciated investment in Trojan?

A. The Commission should revisit this amortization decision because it relies completely on the Commission's assumption that it could allow PGE to recover its costs of equity and debt capital associated by allocating to customers over time the un-depreciated investment. The Court of Appeals ruling that the Commission could not allow PGE a return on the Trojan investment requires that the Commission revisit the period of amortization.

Applying the simple principle that a dollar received in the future is not worth the same as a dollar received today, any delay in PGE's receipt of this investment is a quantifiable decrease in the investment for which the Commission would be granting recovery. The PGE Panel[3] calculated that leaving the amortization period for Trojan's un-depreciated investment at 17 years without a return is the same as an initial disallowance of $182 million. PGE would have experienced an asset write-off of $149 million, lowering its retained earnings in 1995 from $136 million to $46 million.

Q. How was the amortization period for the un-depreciated balance of Trojan investment chosen?

A. The amortization period chosen resulted from the application of ratemaking convention, although the Commission did not discuss this explicitly. If a utility incurs a particular cost to produce a benefit such as lower future costs, the Commission typically sets the amortization of the up-front cost over the period that customers will experience the lower costs. Examples

[3] The PGE Panel is Jay Tinker, Stephen Schue, and Patrick Hager who prepared and appear in PGE Exhibit 6200. That exhibit provides the quantitative analysis PGE is presenting in this docket, other than that quantification done in support of return on equity.

of this convention include the Commission's treatment of amounts incurred to replace higher cost debt with lower cost debt, and its recent decision on treatment of costs incurred to reserve natural gas pipeline space at a low price for eventual use by Port Westward. Order No. 95-322 reflects this convention in its choice of the same period for amortization of Trojan as the 17-year period of the cost-benefit analysis supporting Trojan's closure.

Q. Does good reason exist to change this convention here?

A. Yes, good reason exists for the Commission to shorten the recovery period. As noted above, a 17-year amortization period under the Court of Appeals interpretation of Oregon law results in a disallowance to PGE of $182 million and a write-off of $149 million. Mr. Hager testifies regarding the negative effects this outcome would have had on PGE's ability to attract capital and cost of capital. (PGE Exhibit 6400, Section III). As I discuss in Section IV.E. below, the Commission could have exercised its discretion regarding other elements of ratemaking to achieve the same inter-generational result for customers as the 17-year amortization period achieved but avoid this large financial loss to PGE.

Q. What amortization periods should the Commission consider in deciding this remand proceeding?

A. The Commission should consider a one-year amortization period. We believe it most likely that, had the Commission decided to select a rapid recovery, it would have chosen a one-year period. To prevent any diminution in the amount of un-depreciated investment the Commission found that PGE should recover, the collection period would have needed to be one day. This is not practical. Nor would a one-day recovery be fair between customers, whose usage as of that day may be other than their normal usage. One year captures the

monthly and seasonal variations in customer usage and roughly allocates the cost according to usage patterns.

Q. What outcome or range of outcomes results from revisiting the decision regarding amortization of PGE's un-depreciated Trojan investment?

A. A decision regarding the amortization period for PGE's un-depreciated investment in Trojan affects the UE 88, UE 93, and UE 100 rate periods as well as UM 989. Briefly, a one-year amortization would significantly increase the UE 88 and UE 93 (first four months) revenue requirements and lower revenue requirements in the last part of the UE 93 rate period and during the entire UE 100 rate period. In 2000, PGE would have had no un-depreciated Trojan investment on its balance sheet. On the other hand, the large disparities in rates across the rate periods would require that the Commission evaluate whether the UM 989 result remains reasonable. One method of doing so would be to compare the amounts owed PGE from the UE 88 and first part of the UE 93 rate periods to amounts owed customers from the last half of the UE 93 and UE 100 rate periods. Using this method, the net present value difference in amounts owed PGE and amounts owed customers supports the stipulations approved in UM 989. The PGE Panel details these outcomes in PGE Exhibit 6400, Section II.

B. Required Return on Equity and Capital Structure

Q. Why are you suggesting that the Commission might have made a different decision with respect to the level at which it established PGE's required return on equity (ROE) in UE 88?

A. The Commission's delegation of authority from the Legislature requires that it, among other things, establish a return to the equity holder that is commensurate with the return on investments in other enterprises having corresponding risks. Both when the Commission decided UE 88 and now, few utilities faced or today face the risk of a major loss to their equity holders caused by the early retirement of a generating plant to produce net benefits for customers. PGE's investors face more risk than their counterparts and, thus, PGE's cost of capital is likely higher than for comparable utilities that do not face such a regulatory environment. See generally Makholm and Blaydon, PGE Exhibits 6500 and 6600. The Commission would have considered this greater risk in determining PGE's required return on common equity in UE 88, UE 93, and UE 100.

Q. Was the Commission's determination of PGE's required return on equity in UE 88, UE 93, or UE 100 the result of a convention?

A. No. To determine required return on equity, the Commission typically relies not on convention but on economic models, such as the discounted cash flow (DCF) or capital asset pricing (CAPM) models.

Q. What required return on common equity should the Commission consider in deciding this remand proceeding?

A. PGE Exhibit 6400 supports increases in PGE's required return on equity ranging from 25 to 150 basis points. A basis point is one-hundredth of a percent. The lower end of the range represents the increased risk to investors in Oregon utilities related to the Court of Appeals interpretation of Oregon law and a short amortization period. The higher end of the range relates to risk investors would perceive if the system of economic regulation in Oregon forced utilities to receive, over an extended period with no return on investment, their un-

depreciated investment in generating plants economically retired before the end of their depreciation lives.

Q. What outcome or range of outcomes results from re-determining PGE's required return on equity?

A. Applying the range to UE 88, UE 93, and UE 100 results in revenue requirements $17 million to $102 million higher than the Commission would otherwise have found. The PGE Panel demonstrates this at PGE Exhibit 6200, Section III.

Q. Does similar reasoning underlie your suggestion that the Commission might have, for purposes of ratemaking, established a different capital structure for PGE?

A. Yes. The Commission's delegation of authority also requires that the rates be sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital. Although a higher ROE that provided PGE an opportunity for greater net income would contribute to financial integrity, use of a hypothetical capital structure with greater amounts of equity would also accomplish this result.

Q. Was the Commission's determination of capital structure for PGE in UE 88, UE 93 and UE 100 the result of applying a convention?

A. Yes. Historically, the Commission has used a utility's actual capital structure during the one-year test period it is using to set rates, if this is known. In other words, for a utility such as PGE, the Commission would use PGE's forecast capital structure for the test year. Sometimes the Commission cannot know a utility's actual capital structure for utility service because the utility has significant non-utility activities within its business structure. In such cases, the Commission has used a hypothetical capital structure.

Q. Does good reason exist to use a hypothetical capital structure for PGE during the UE 88, UE 93, and UE 100 rate periods, rather than the actual capital structure used by the Commission in its initial decisions?

A. Yes. Depending on the other decisions the Commission decides that it would have made. As Patrick Hager explains in PGE Exhibit 6400, Section III, a Commission decision to amortize Trojan's un-depreciated balance over 17 years would significantly worsen the financial ratios by which credit rating agencies decide whether a utility is credit-worthy. A hypothetical capital structure could help restore the ratios to levels that will help attract future capital. PGE Exhibit 6401.

Q. What outcome or range of outcomes might result from re-visiting this issue?

A. Use of a hypothetical capital structure with greater amounts of equity would increase UE 88, UE 93 and UE 100 revenue requirements, all else being equal. The PGE Panel does not quantify these outcomes because they are similar to the outcomes PGE quantifies for a higher required return on equity.

C. Calculation and Application of Net Benefits

Q. Which factual and policy decisions in the calculation of the net benefits test are you suggesting that the Commission revisit and why?

A. PGE suggests that the Commission revisit in this remand proceeding one factual and one policy decision included in the UE 88 calculation of the net benefits test.

The factual decision relates to costs included on the replacement resources side of the net benefits test comparison. In the UE 88 calculation of the net benefits test, the Commission included recovery by PGE of our Trojan investment over 17 years, with a return on the un-

depreciated balance, matching the recovery of and return on Trojan assuming continued operation. Under the Court of Appeals interpretation, this must change. As explained above (and, in more detail in PGE Exhibit 6200, Section IV), whether amortization of the un-depreciated balance is over one year or 17 years, excluding any return on investment effectively reduces the cost to customers, and thus increases the benefit of closure. All else being equal, this will lower the cost of the replacement resources side of the net benefits test, increasing the net benefit to closure. The PGE Panel calculates that adjusting the net benefits test for the Court of Appeals interpretation results in a net benefit for closure of $-4 million assuming a one-year amortization period and $155 million assuming a 17-year amortization period. This adjustment is consistent with and required by the Commission's methodology.[4]

The policy decision relates to costs included on the continued operation of Trojan side of the net benefits test comparison. In UE 88, the Commission exercised its discretion to exclude from the costs of Trojan's continued operation amounts PGE would have incurred to replace Trojan's steam generators. This exclusion did not rely on any finding of imprudence by PGE; indeed, the Commission explicitly found that PGE had acted prudently with respect to both the purchase and maintenance of the steam generators that would require replacement. Order No. 95-322 at 3. Nor did the Commission find that PGE could have operated Trojan for its remaining license life without new steam generators. Nonetheless, the Commission ultimately decided in the context of UE 88 to allocate the consequences of the steam generators' problems to PGE, stating that:

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[4] As Order No. 95-322 explains, the net benefit test is a scenario comparison: the future costs of continued Trojan operation compared to the future costs of other resources. Footnote 16 on page 32 of that Order states: "Under the net benefits analysis, sunk investment cost is added to the cost of each option. . . . . The net benefit treatment of sunk investment cost does not . . . change the difference between the costs of any two options . . . ." Had the Commission known of the Court of Appeals decision, it could not have made this statement.

> "Although PGE's behavior was not faulty, PGE and the ratepayers are the only two parties to whom we can assign or impute steam generator costs. As between those two parties, PGE is better situated to recover its costs from the manufacturer of the steam generators. Moreover, it is fair that shareholders bear some of the consequences of management investment decisions." Order No. 95-322 at 3.

Order No. 95-322 is clear that the Commission's decision to exclude the steam generator replacement costs from the continued operation scenario in the net benefits test was an exercise of its discretion. It noted PGE arguments against the exclusion and emphasized that its decision on cost recovery was not meant to act as precedent for any future outcome.[5]

We suggest here that, had the Commission known that the Court of Appeals would interpret ORS 757.355 to prohibit rates that included a return on the remaining Trojan investment, the Commission might not have exercised its discretion on this issue as it did. It might not have found it "fair" to allocate this cost to shareholders. No convention dictated the original result and none inhibits a different decision now. Indeed, good regulatory policy supports reversing this UE 88 decision. Holding investors solely responsible for prudently incurred costs shifts significant risk to such investors. As Dr. Makholm explains, (PGE Exhibit 6500) one of the most fundamental investor expectations about a regulator is that the regulator will allow the utility an opportunity to recover prudently incurred costs through its rate decisions. The UE 88 net benefits test decision on the steam generators violates this expectation, raising questions for the future, even though the Commission attempted to minimize the effect by stating it would make such decisions on a case-by-case basis. Given the risk that the Court of Appeals interpretation has added to Oregon's regulatory environment, it makes little sense to

[5] Subsequent to UE 88, PGE resolved its claims against Westinghouse. The settlement of that litigation resulted in a payment of about $4 million by Westinghouse, which PGE credited to customers in the UM 989 stipulation. The $187 million excluded by the Commission from the net benefits test dwarfs the amount PGE was ultimately able to recover from the manufacturer.

add more risk by preserving this decision to exclude steam generator replacement costs from the net benefits test calculation.

Q. Might the Commission have made different decisions regarding other inputs to the net benefits test used in UE 88?

A. Yes. Order No. 95-322 discusses and resolves a number of inputs to the net benefits test for which competing views were presented. Most of the Commission's decisions chose inputs that lessened the amount of net benefit created by early retirement, creating a conservative result. Were the Commission to revisit any of these decisions, the amount of net benefits from retirement would increase. Although PGE is not presently suggesting that the Commission needs to engage in this retrospective review of the disputed inputs to the net benefits test, we ask that the Commission recognize the conservative quality of the original net benefits result in determining how to apply the net benefits result in this remand proceeding.

Q. What is the effect on the result of the net benefit test of the factual and policy decisions you suggest that the Commission re-visit?

A. Adding the steam generators to the cost of continued operation increases the net benefits of closure by $183 million, all else being equal. With both changes I discuss above, the PGE Panel estimates net benefits ranging from $179 million, assuming one-year amortization of Trojan's un-depreciated balance, to $338 million assuming 17-year amortization.

Q. Why should the Commission revisit its application of the result of the net benefits test?

A. The Commission should revisit the result of its application of the net benefits test because, in UE 88, it considered only how it might apply a negative net benefit. The factual and policy decisions made in calculating net benefits for UE 88 resulted in a negative net benefit of $27

million (pre-tax).[6] Thus, the Commission's regulatory policy analysis considered the net benefits test only in the context of "a tool to determine where ratepayers are held harmless for imprudent operation or management of Trojan, and to share costs between ratepayers and shareholders on that basis." Order No. 95-322 at 2.

Order No. 95-322 does not discuss how the Commission might have exercised its discretion had the result of the calculation of the net benefit test been the positive $179 million to $338 million I note above. These are significant net benefits to customers that the Commission would want to encourage utilities to look for, even with the ruling that investors cannot receive a return on generating plants economically-retired before the end of their depreciation lives to achieve least cost for customers.

Q. What applications of a positive net benefit calculation should the Commission consider in this remand proceeding and why?

A. The Commission should consider two applications of a positive net benefit calculation in this proceeding. First, it should consider reversing the disallowance of a portion of Trojan's un-depreciated balance. This decision rests entirely on the factually-derived negative outcome of the net benefits test. The Commission found a negative net benefit to closure of $27 million in UE 88 and ordered a corresponding disallowance to PGE's un-depreciated Trojan investment. A positive net benefit requires reversal of the $27 million disallowance.

Second, the Commission should consider whether, to encourage future analysis and implementation of early plant retirements that are in the public interest and under least cost planning principles, a "share-the-savings" mechanism could be appropriately applied to the calculated net benefit. The Commission approved a similar mechanism in connection with

[6] The after-tax number was $20.4 million.

another outcome of least cost planning: the acquisition of energy efficiency resources by utilities. In Order No. 91-98, the Commission adopted the SAVE program for PGE. This program, which was designed to "motivate PGE to aggressively pursue cost-effective energy efficiency measures," included a financial incentive for energy efficiency investment. As the Order explains:

> "The incentive component of the SAVE proposal allows PGE to earn revenues in addition to the allowed rate of return on capital investment over a period of 15 years. It provides for a sharing of the savings from non-use of electricity based on the value of verified energy efficiency savings that exceed benchmark levels." Order No. 91-98 at 3.

The SAVE incentive component is an instance of the Commission departing from the convention of basing rates on direct costs of electricity service. When necessary to promote important policies, such as the least cost planning framework, the Commission has discretion to depart from such conventions.

Q. What outcome or range of outcomes would result from the Commission revisiting its application of the net benefits test, restated for the revised calculations?

A. I addressed above the restoration of the $27 million disallowed from Trojan's un-depreciated balance.

With respect to a share-the-savings mechanism, any number of models exists. The SAVE mechanism ultimately resulted in an incentive payment of over 50 percent of the amount PGE invested in demand-side resources over the three-year period 1991 through 1994. The power cost adjustment (PCA) in place from the late 1970s to 1987 gave PGE 20 percent of the savings achieved from a quarterly-updated baseline net variable power cost. In UE 47/48, the Commission allocated to PGE 23 percent of the gain PGE created by selling a portion of our Boardman generating plant with an accompanying long-term power

purchase agreement.[7] For purposes of creating building blocks to use in this remand proceeding, we chose the 20 percent incentive of the PCA design.

The PGE Panel calculates that reversing the disallowance and adding a share-the-savings incentive increases revenue requirements across UE 88, UE 93 and UE 100 by $17 million.

D. Plant Classification

Q. Why are you suggesting that the Commission revisit its UE 88 decision regarding classification of Trojan's assets between plant-in-service and un-recovered plant accounts?

A. The Commission should revisit its decision regarding the classification of Trojan assets between plant-in-service and unrecovered plant because, as with its decision regarding an amortization period for un-depreciated Trojan investment, it relied on the assumption that it could allow PGE to recover its costs of capital regardless in which account PGE recorded the assets (Order No. 95-322 at 53). In other words, as the law stood when the Commission made this decision in UE 88, the decision made no practical difference.

In UE 88, the Commission acknowledged "that there is no prescribed method of accounting for nuclear plants that are in the process of being decommissioned." Based on evidence PGE presented in UE 88 and PGE Exhibit 6300, Quennoz-Peterson-Dahlgren, the Commission should find that certain Trojan assets remained in utility service to protect public safety and support decommissioning activity. The Commission may set a return of and on assets that remain in service. These assets are not subject to the Court of Appeals interpretation restricting the Commission's discretion to set rates by precluding a return on

[7] Order No. 87-1017 at 30.

assets that no longer provide service.

Although Order No. 95-322, at p. 54, cites FASB[8] Statement 90 as supporting the classification of assets to un-recovered plant, this provides limited guidance because one first must decide what "asset" is being abandoned. PGE was not abandoning any component of Trojan that remained necessary to protect public safety or enable government-required decommissioning work. These assets remained in service. An electric utility has many assets and components of assets not directly involved in generating or delivering electric energy. Fish ladders at hydro-electric generating plants and fences at substations are two examples. These facilities are used and useful to accomplish their utility service purposes and would remain so even if the hydro-electric plant or the substation were no longer in use to generate or distribute electricity.

Q. What outcome or range of outcomes could result from revisiting this decision?

A. Stephen Quennoz, Pete Peterson and Randy Dahlgren, PGE Exhibit 6300, support the analysis PGE presented in UE 88 that showed $80 million in un-depreciated Trojan investment remained in utility service following the closure decision. The PGE Panel calculates that, all else being equal, the proper classification increases revenue requirements in UE 88, UE 93 and UE 100. It also increases the un-depreciated balance remaining at the time of UM 989 even if the Commission chose a one-year amortization period for the un-depreciated investment that did not remain plant-in-service because these in service assets would have remained on the original 17-year depreciation life.

[8] FASB stands for Financial Accounting Standards Board.

E. Amortization Periods for Certain Customer Credits

Q. Are there amortization periods for balance sheet items other than Trojan that the Commission should consider?

A. Yes. PGE's 1995 balance sheet included a customer credit for the gain achieved in the 1985 sale of a portion of the Boardman plant. The Commission set a 27-year amortization period for that credit in UE 47/48. Order No. 87-1017 at 30. In UE 88, the Commission left the Boardman gain amortization period unchanged but, in UE 93, it accelerated these credits to use as offsets to several amounts customers owed PGE, including the AMAX termination payments, power costs deferred in several years, and the SAVE incentive PGE had earned. The Commission should, on remand, offset the remaining Boardman gain against an equal amount of un-depreciated Trojan investment before setting UE 88 rates. This would require that the Commission also establish amortization periods for AMAX, the deferred power costs, and SAVE in UE 93.

Q. Why should the Commission revisit this policy decision?

A. The reason why the Commission should revisit its policy decision to leave Boardman on a 27-year amortization schedule depends on the amortization period it decides is appropriate for PGE's un-depreciated Trojan investment in light of the Court of Appeals ruling.

If the Commission decides that a one-year amortization of Trojan is appropriate, accelerating Boardman's amortization would improve the matching of costs and benefits over time. Revisiting the amortization of Boardman improves the inter-generational equity associated with allowing PGE to recover its un-depreciated investment entirely from one year's customers, while customers would receive the benefits of such closure over at least 17 years.

If the Commission decides that a 17-year amortization of Trojan remained appropriate, accelerating amortization of the Boardman gain lessens the negative impact of the Trojan decision on PGE's financial integrity and ability to attract capital. Allowing PGE to offset the amounts owed customers for the Boardman gain with the amounts owed its investors for Trojan in effect allows PGE to recover some of the outstanding balance in one day. Although a one-day recovery is impracticable as a ratemaking matter, it is not impossible if accomplished as a netting of balance sheet entries. Because PGE would have experienced no loss of the time value of money associated with the amount of Boardman gain so applied, our write-off would have been less: $98 million rather than $149 million.

Q. Was the amortization period chosen for the Boardman gain the result of applying a ratemaking convention?

A. No. The amortization period for a credit to customers such as the Boardman gain is entirely within the Commission's discretion and should serve regulatory policy. No specific conventions exist. In the 1987 general rate case, UE 47/48, the Commission set the Boardman gain on a 27-year amortization schedule to match the period customers would have received such amounts had the sale of the plant been only a power sale instead of an asset sale accompanied by a power sale. The Commission found reason to depart from this rationale in November 1995, for UE 93. We suggest that, in light of the Court of Appeals interpretation, good reason now exists to shift that reconsideration of the Boardman amortization period from November to March 1995.

Q. What is the outcome of revisiting this decision?

A. Applying the remaining Boardman gain to reduce the un-depreciated Trojan investment available for ratemaking has various effects on the UE 88, UE 93 and UE 100 rate periods

and on the un-depreciated balance remaining at the time of UM 989. These effects depend on the combination of other building blocks assumed. Generally, applying the remaining Boardman gain to reduce the Trojan balance reduces the lost economic value resulting from collecting Trojan with no return over any assumed amortization period.

F. Recovery Timing of 1995 Net Variable Power Costs

Q. Why are you suggesting that the Commission revisit the timing of recovery of PGE's 1995 net variable power costs?

A. Revisiting this policy decision may be appropriate if the Commission decides that, on remand, the UE 88 amortization period for PGE's un-depreciated Trojan investment should be one year.

In UE 88, the Commission followed the standard ratemaking convention of setting rates to recover current costs, including net variable power costs. The Commission departs from this convention, however, when good reason exists to do so, such as a temporary and material rise in power costs. The first nine months of 2001 were a good example of this. In such cases, the Commission sets aside a portion of the current incurred costs for later recovery. The Commission spread the 2001 excess power costs over a period of almost 4 years, from 2002 through 2005. Among other purposes, this practice improves rate stability and predictability by smoothing unexpected lumpiness in costs.

If the Commission decided, on remand, that PGE should amortize its Trojan investment over one year, the total revenue requirement of current power costs and Trojan recovery would be temporarily high. In these circumstances, deferring a portion of current 1995

power costs for recovery in subsequent years would simultaneously improve the matching of the costs and benefits of the Trojan closure decision and increase rate stability.

Q. Was the inclusion of all of the 1995 forecasted net variable power costs in rates the result of applying a ratemaking convention?

A. Yes. As I explained above, the Commission typically considers, in setting rates for a given rate period, all of the costs the utility expects to incur to provide service during that period.

Q. Does good reason exist to change this convention here?

A. Yes, good reason exists if the Commission also decides that, in UE 88, it would have set the amortization period for PGE's un-depreciated Trojan balance at one year. The one-year increase and subsequent decrease in rates resulting from the Trojan amortization decision would have created rate instability, affecting customers' ability to make sound economic decisions regarding their use of electricity. In addition, the one-year period would not have matched the costs of achieving the net benefits of Trojan's closure with customers' receipt of those benefits. Deferring a portion of 1995 net variable power costs would help the Commission achieve this matching.

Q. What would be the outcome of revisiting this policy decision?

A. Revisiting this decision, in the context of a one-year amortization of un-depreciated Trojan investment, lowers UE 88 and four-months of UE 93 revenue requirements and increases subsequent revenue requirements. A significant amount of deferred power costs would have remained at the time of the UM 989 stipulation. The PGE Panel calculates the rate levels and balance sheet effects associated with this decision assuming that the Commission exactly offsets the un-depreciated Trojan investment with a power cost deferral. When

combined with other building blocks, the results of this assumption are provided by the PGE Panel. PGE Exhibit 6200, Section IX, Part B.

G. UE 88 Interest Costs

Q. Why do you suggest that the Commission, on remand, might include all of PGE's interest costs in rates, regardless of whether some of the debt related to un-depreciated Trojan investment?

A. We make this suggestion both on a legal basis, as explained in PGE's Pre-Trial Brief, Section V, Subsection H and because, from an economic perspective, it seems particularly unfair to claim that the prohibition of ORS 757.355 relates to the entire financing cost of the utility. Prohibiting an equity return requires that equity investors accept a zero return on their investment. However, forcing equity investors to pay the costs of debt financing imposes a further burden on equity investors and in fact requires that they accept a negative return to cover the contractual debt payments. In the case of Trojan, disallowing the debt and interest payments causes equity investors to lose approximately $41 million over the 5.5 years from April 1995 to September 2000 and $76 million over the full 17-year period in addition to the lost profit. PGE Exhibit 6201, Page 2.

Q. Would excluding both interest and profit related to un-depreciated Trojan investment be the result of applying a convention?

A. Yes. The Commission currently uses a specific rate times rate base – the term from the statute – to determine the basis for both a utility's interest costs and the cost of its common equity. This is the usual, although not the only, choice for common equity. But one can find the expected amounts of interest payments from a utility's accounts without regard to

rate base. Ultimately, the Commission is regulating to achieve an allowed return on equity and essentially a fixed component like O&M.

Q. Does good reason exist to change this convention here?

A. Yes. As with other factual decisions and policy choices I discuss above, applying this convention in UE 88 made no difference until the Court of Appeals interpretation. The Commission believed it could allow PGE to recover all of its capital costs – debt and equity – as well as its un-depreciated investment. This assumption is no longer valid. Applying this conventional way of calculating return will result in the penalty to equity investors explained above: not only will these equity investors lose their profit opportunity, but they will be required to cover the interest payments that must occur until the debt is retired.

We also note that some other jurisdictions (cited in PGE's Opening Brief), under similar but not identical circumstances, differentiated between the interest owed with respect to money borrowed for an uncompleted generating plant and the potential profit the utility would have made, denying the utility that potential profit but not requiring that the utility take a loss by absorbing the cost of the borrowed money.

H. Building Blocks Conclusion

Q. Are the above the only factual decisions and policy choices the Commission might have made differently in UE 88, had it known of the Court of Appeals interpretation?

A. No, they are not. It is impossible to know how knowledge of the Court of Appeals interpretation would have influenced the Commission's cumulative exercises of discretion in UE 88 as it strove to set rates that, in their end result, fell within the scope of its statutory

delegation, satisfied constitutional requirements and met the criteria I described in Section III. These are, however, the most obvious ones.

V. PGE's Position

Q. Please restate PGE's position from Section I of your testimony.

A. If the Commission had known that it could not establish rates including a return on undepreciated balances of economically-retired generating assets even if it spread the recovery of such balances over time, then:

- In 1995, the Commission would have found fair and reasonable rates at least as high, if not higher, than the rates approved in Docket UE 88, Order No. 95-322; and
- In 2000, the Commission approved of the stipulations presented to it and the proposed $10 million rate reduction as fair and reasonable and a proper exercise of its discretion as a Commission in Docket UM 989, Order No. 00-601, because amounts owed PGE at that time would have exceeded the customer credits used as an offset. This would have provided economic as well as other benefits to customers from the resolution of the issues.

Q. What is the basis of your position?

A. We base our position on two sets of factual and policy decisions that we would have recommended in UE 88, either one of which we believe the Commission could and would have adopted. These sets of decisions meet the criteria I described above, although not to the same degree or in the same way.

Q. What is the first set of factual and policy decisions PGE would have requested that the Commission find in UE 88?

A. PGE would have requested, and believes the Commission reasonably would have found, that PGE should:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation and including the effects of the Court of Appeals ruling in the costs of closure and steam generator replacement in the costs of continued operation.
- Leave $80 million of the Trojan assets in the plant-in-service accounts.
- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not still plant-in-service and amortize the remainder over one year.
- Be allowed a required return on equity of 11.85 percent.
- Defer a portion of its 1995 and 1996 (four-months, to match the period of Trojan recovery) net variable power costs, for recovery over the subsequent ten years.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs and SAVE incentive over the same ten years.

The PGE Panel (PGE Exhibit 6200, Section IX.B) presents the effect of these revised factual and policy decisions on UE 88, UE 93, UE 100, and UM 989. The results, summarized in Table 1 below, show that no refund is due for any rate period because the UE 88, UE 93, and UE 100 rates are all the same or higher than the rates in effect during those periods:

Table 1
($000)

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirements	Revenue Requirement Difference
UE 88	621,028	627,510	6,482
UE 93	1,003,794	1,011,340	7,546
UE 100	3,674,898	3,679,829	4,931

The results also show that sufficient assets existed on PGE's balance sheet as of 2000 to support the offsetting of amounts owed PGE, $180 million, and amounts owed customers,

$161 million, per the stipulations the Commission exercised its discretion to adopt in UM 989.

Q. How does PGE's position comport with the criteria you presented in Section III?

A. Our position serves all of the criteria we presented above. I will address each separately.

Q. Please restate the first criterion and explain how PGE's position satisfies it.

A. Our first criterion uses the question:

> Does this decision encourage electric utilities to analyze and make resource decisions that will yield, "for society over the long run, the best combination of expected costs and variance of cost" to "assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"

PGE's position is at least neutral on this criterion. The use of a one-year amortization would have resulted in a $24 million write-off on PGE's balance sheet in 1995. This would not have been particularly encouraging, particularly when added to the $5 million additional write-off PGE took in connection with the UM 989 stipulations.[9] On the other hand, the higher required return on equity improves debt coverage and provides equity investors the opportunity for higher earnings. Also encouraging are the restoration of the previously-disallowed amount and the proper classification of assets necessary to protect public safety as utility plant in service.

Q. Please restate the second criterion and explain how PGE's position satisfies it.

A. Our second criterion uses the question:

> Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable

[9] These write-offs are additive to the $53 million pre-tax write-off ordered in UE 88.

burden of the costs or receives an inequitable share of the benefits?

PGE's position answers this question positively. No annual generation of customers over the period 1995 through 2000 would have borne an inequitable share of the costs of the least cost decision to close Trojan, nor received an inequitable share of the benefits.

Q. Please restate the third criterion and explain how PGE's position satisfies it.

A. Our third criterion asked the question:

> Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

PGE's position allows a positive answer to this question, for many of the same reasons as discussed under the first criterion.

Q. What is the second set of factual and policy decisions that PGE would have requested that the Commission find in UE 88?

A. PGE would have requested, and believes the Commission could reasonably have found that PGE should:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation and including the effects of the Court of Appeals interpretation in the costs of closure and steam generator replacement in the costs of continued operation.
- Receive 20 percent of the positive net benefit created through its economic retirement of Trojan, spread evenly over 17 years.
- Leave $80 million of the Trojan assets in plant-in-service accounts.

- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not still plant-in-service.
- Be allowed a required return on equity of 13.1 percent.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs and SAVE incentive over three years beginning with UE 88 rates.

The PGE Panel (PGE Exhibit 6200, Section IX.C)presents the effect of these revised factual and policy decisions on UE 88, UE 93, UE 100, and UM 989. The results, summarized in Table 2 below, show that no refund is due for any rate period because the UE 88, UE 93, and UE 100 rates are all the same or higher than the rates in effect during those periods:

Table 2
($000)

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirement	Revenue Requirement Difference
UE 88	621,028	621,090	63
UE 93	1,003,794	1,029,157	25,363
UE 100	3,674,898	3,707,946	33,048

Q. Please explain how well this scenario answers the question posed as criterion one.

A. Again, criterion one asks the question:

> Does this decision encourage electric utilities to analyze and make resource decisions that will yield, "for society over the long run, the best combination of expected costs and variance of cost" to "assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"

This scenario makes it harder to answer the question positively because, regardless of some of the positive regulatory policies assumed in this scenario, the result in 1995 would have been a $71 million write-off for PGE. The opportunity to earn a return on equity adjusted for the increased risk investors faced and the share-the-savings payment would have increased the return investors had an opportunity to earn, but such results would have come

only over time and subject to the outcome of other risks PGE faced then. The proper classification of Trojan assets in utility service to protect public safety or accomplish decommissioning also helps encourage least-cost planning decisions by subjecting to the incremental cost analysis only those costs truly avoidable. Protecting safety or meeting governmental requirements for decommissioning are not avoidable.

Q. Please explain how well this scenario answers the question posed as criterion two.

A. Again, this criterion asks:

> Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable burden of the costs or receives an inequitable share of the benefits of a given resource decision?

The continued use of a 17-year amortization schedule does help match the costs of closure well with the benefits customers would receive over the period of the net benefits analysis.

Q. Please explain how well this scenario answers the question posed as criterion three.

A. This criterion asks:

> Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

This scenario answers this question fairly well. The initial write-off would have weakened PGE's financial condition. Barring significantly unfavorable outcomes to the risks the Commission's ratemaking policies allocated to PGE (load, water, fuel), however, the opportunity to earn a higher return through the risk-adjusted required return on equity and

the temporary share-the-savings mechanism would have improved PGE's financial condition.

Q. Could the Commission, in deciding UE 88, have put the building blocks you discuss together in ways other than PGE's position and the 17-year scenario you discuss above?

A. Yes. For example, the Utility Reform Project (URP) has suggested that all revenue requirement associated with Trojan recovery of and return on should be applied against the un-depreciated balance of Trojan over the UE 88, UE 93 and UE 100 rate periods. One could construe this scenario as one in which the Commission sets an amortization period for the un-depreciated Trojan investment, such that the revenue requirement associated with return on that spread investment, is actually return of investment. This is not precise because using the "return on" revenue requirement in this way does not match any definite multiple-year amortization period.

Q. How would such a scenario measure against the criteria you presented?

A. It would measure up poorly. This scenario would have resulted in an immediate 1995 write-off of $149 million, harming PGE's financial health. Certainly, PGE and all other utilities would have felt no encouragement to engage in least cost planning analysis for existing plants, let alone implement a least-cost decision to retire one before the end of the depreciation life set by the Commission. The lack of recognition of increased risk associated with ORS 757.355 would discourage new investment, debt or equity. Although superficially this scenario would perform adequately at matching costs and benefits over time, in reality, significant costs would have been shifted to future customers, along with some risk that service would not be adequate.

Q. Would these ill-effects in fact have happened in 1995 and subsequent years?

A. No. We are now in 2005. The effects of any decision regarding what the Commission would have done in 1995 through 2000 will have no effect in those years. The effects will happen in 2005 and beyond. We will address this in more detail in Phase II of this docket, if necessary, but it is worth noting that the future effects of adopting scenarios that fail the criteria we present will affect future customers.

VI. Summary of Testimony

Q. Please identify the exhibits PGE is presenting.

A. PGE is presenting the following exhibits:

PGE Exhibit 6100 Ratemaking, Trojan History. Witness Randy Dahlgren reviews the basic methods and principles of ratemaking and describes the sequence of events in Oregon from Oregon's adoption of least cost planning through to the UM 989 settlement.

PGE Exhibit 6200, Quantitative Analysis (PGE Panel). Witnesses Patrick Hager, Jay Tinker, and Stephen Schue quantify the UE 88, UE 93, UE 100 and UM 989 balance sheet effects of the building blocks and assemble those into the one-year and 17-year scenarios I described in Section V.

PGE Exhibit 6300, Asset Classification. Witnesses Stephen Quennoz, Pete Peterson, and Randy Dahlgren explain why the work done to determine appropriate FERC accounting for Trojan assets upon its closure in 1993 should guide the Commission's classification of such assets for purposes of this UE 88 remand and why the earlier classification remains conservative based on knowledge subsequently gained.

PGE Exhibit 6400, Cost of Capital. Witness Patrick Hager explains why the Commission should have found that PGE's required return on equity in UE 88 was in the upper end of the range presented in that docket. He also details effects on PGE's ratios used by credit rating agencies to assess the security of amounts loaned PGE for un-depreciated Trojan investment amortization periods of one and seventeen years. Based on this analysis, he calculates a hypothetical capital structure that could help mitigate some of the negative effects of the amortization decision on PGE's ratios.

PGE Exhibit 6500, The Regulatory Compact. Witness Dr. Jeff Makholm, of the National Economic Research Associates, presents the principles of the regulatory compact as it has developed in the U.S., presents examples in other state jurisdictions of how Commissions have upheld the regulatory compact when dealing with retirement of nuclear plant which had a remaining depreciable basis, and explains how the Court of Appeals interpretation of ORS 757.355 jeopardizes the compact for both investors and customers in Oregon.

PGE Exhibit 6600, Impact on Rate of Return. Witness Dr. Colin Blaydon applies Discounted Cash Flow theory to concur that the required return on equity recommended by Patrick Hager is reasonable.

PGE Exhibit 6700, Risk Premium. Witness Dr. Alan Hess shows that equity investors require a risk premium on their required return under circumstances of asset impairment.

V. Qualifications

Q. Please state 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.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE-88 REMAND

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Pamela G. Lesh
Randy Dahlgren
Jay Tinker
Stephen Schue
Patrick G. Hager
Stephen M. Quennoz
Leonard S. Peterson
Jeff D. Makholm, Ph.D
Colin C. Blaydon, Ph.D
Alan C. Hess Ph.D

PGE

Portland General Electric

February 15, 2005

UE-88 REMAND / PGE EXHIBIT / 6000
LESH

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy & Recommendations

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Pamela G. Lesh

February 15, 2005

I. Introduction

Q. Please state your name and qualifications.

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

Q. What is the purpose of this proceeding?

A. This proceeding has its roots in events that began in the early 1990s, shortly after the Commission adopted least cost planning as the process and methods by which Oregon utilities would select the future resources they would use to serve customers. The process the Commission ordered was one of broad inclusion, allowing everyone with an interest the opportunity to understand and provide input on a utility's resource decisions. The method was one of evaluating both supply-side and demand-side resources on a consistent basis and considering both the internal and external costs of resource decisions.

Using the least cost planning process and methods, PGE filed with the Commission in 1992 a plan recommending that we phase out our Trojan generating plant over four years, replacing it with other resources which had a projected lower cost than Trojan. This recommendation had wide support among a large group of participants in our process. When Trojan's condition, and economics, worsened at the end of 1992, PGE quickly analyzed whether immediate closure would increase the benefit to customers over phase-out and, because it did, we closed the plant in January 1993. The Commission ultimately acknowledged both the phase-out and subsequent immediate closure decisions as producing lower costs for customers than continued Trojan operation. Throughout the planning process, PGE assumed that, if closure was the most economic choice for customers, PGE

could recover its remaining investment in Trojan because this sunk cost would exist given either course of action.

Late in 1993, PGE filed a general rate case, UE 88, to adjust our revenue requirement for this significant resource decision. We knew that processing the case would require many months and intended that the rates take effect January 1995. The case's revenue requirement included return of and on PGE's investment in Trojan over the 17 years remaining under the nominal depreciation life the Commission had set for Trojan when it entered service. Filing this way best matched the costs and benefits of the least cost resource decision for customers and did not harm PGE because, as we and the Commission understood Oregon law at the time, the Commission could allow us to recover both return of and on this investment retired to produce economic benefit to customers.

Following the Commission's decision in March 1995, several parties argued to the Oregon courts that Oregon law does not allow return on a utility's investment in a plant it has retired for economic reasons. The Court of Appeals ultimately agreed in 1998 and remanded UE 88 to the Commission. The Oregon Supreme Court accepted the case for further review. In 2000, while that appeal was pending, PGE, CUB and Staff jointly proposed to the Commission, UM 989, a way to eliminate PGE's remaining investment in Trojan, matching this amount owed PGE with a somewhat smaller amount PGE owed customers. The Commission's order approving this proposal was also appealed and, in 2003, remanded to the Commission. Our opening brief discusses both remand orders. The Commission considers the scope of this phase of the process to determine what rates it would have set in UE 88 and whether it would have approved the proposal in UM 989, had it known that Oregon law precluded it from setting rates including a return on investment in

a generating plant retired for economic reasons. If the Commission finds that it would have set lower rates, it will next determine the amount, if any, of refunds to customers. We are engaged here in presenting facts and arguments regarding what the Commission would have done ten and five years ago in UE 88 and UM 989, respectively.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present PGE's case regarding the questions this remand proceeding requires the Commission to answer. Relying on the records originally developed in UE 88 and UM 989 and the testimony we file here, I explain what PGE would have urged the Commission to do in the dockets now on remand. What we propose assumes everyone knew throughout the 1990s that Oregon law precludes a Commission from allowing utility investors a return on money invested in a generating plant that is retired because it is more economic for customers to replace the plant's output than for the utility to continue operating it. The prohibition exists even though retirement before the end of the Commission-approved depreciation life produces lower costs for customers than continued operation.

Had the Commission known of this interpretation of Oregon law, it would have had many choices available to it. PGE has identified choices that are consistent with the overarching goal of regulatory policy, that promote analysis and action by utilities to achieve the least cost for customers, that allocate utility costs to customers fairly over time, and that maintain a utility's ability to access capital so that utility service remains safe and adequate. Choices other than those we present here likely exist. But such choices are poor if they do not serve these goals and objectives. Both then – in 1995 and 2000 – and now, choices that do not

serve the goals and objectives of regulation would have resulted and will result in regulation that does not serve customers.

PGE's evidence shows that, had the Commission known of the constraint Oregon law places on its ability to spread the un-depreciated cost of generating plant retired to achieve lower costs:

- In 1995, the Commission would have found fair and reasonable rates at least as high, if not higher, than the rates approved in Docket UE 88, Order No. 95-322; and
- In 2000, the Commission would have approved the stipulation presented to it and the proposed $10 million rate reduction as fair and reasonable and a proper exercise of its discretion in Docket UM 989, Order No. 00-601, because amounts owed PGE at that time would have exceeded the customer credits used as an offset. This would have produced economic as well as other benefits to customers from the resolution of the issues.

I explain the regulatory policy supporting PGE's position and summarize the quantitative analysis underlying it. Our position accepts, for purposes of this policy and quantitative review that the underlying legal theories comply with statutory and constitutional requirements.[1]

Q. How is your testimony organized?

A. My testimony is organized into six sections.

[1] In doing so, PGE is not waiving any legal arguments regarding the availability of refunds for UE 88, UE 93, or UE 100, or the consideration of allegedly "excess" rates in UE 88, UE 93, and UE 100 in the Commission's evaluation of UM 989. Nor is PGE addressing, or waiving, our policy arguments regarding why, even if refunds or adjustment of PGE's balance sheet for past excess rates were legally supportable, such steps would be inadvisable from a regulatory policy perspective and the Commission could exercise its discretion to reject such actions. It is our understanding that we can make our case regarding the advisability of refunds in phase II of this proceeding.

- In Section II, I briefly review the regulatory and ratemaking context for this remand proceeding;
- In Section III, I explain the approach we followed to reach our position;
- In Section IV, I review the reasons for each of the factual or policy decisions from the remanded cases that PGE examined in developing our position;
- In Section V, I explain our position, using the methodology of Section III and certain of the building blocks of Section IV; and
- In Section VI, I summarize the other testimony PGE is presenting.

Q. Are there any explanations necessary with respect to PGE's testimony in this case?

A. Yes, there are two contextual explanations. The first explanation concerns the amount of general ratemaking and background information we are presenting in this docket. Our review of such fundamentals does not imply a belief that the Commission, or the parties, require education in such matters. Indeed, much of it is what any participant in the economic regulation arena learns in his or her first rate case and never consciously thinks about again. But what we "veterans" take for granted, can leave a record that is difficult for a reviewing court to understand. We believe that the unusual nature of these remanded rate determinations requires that we provide a foundation that would not otherwise be necessary.

The second explanation concerns the difference between revenue requirement and rates. The remand orders refer to rates. As the scoping ruling indicates, rates are the result after the Commission determines revenue requirement, allocates that revenue requirement across all of the utility's tariffs (rate spread) and among the billing determinants within each tariff (rate design) and, for those billing determinants based on energy usage, applies the retail load forecast to determine a per kWh rate. For purposes of our quantitative analysis in this

phase, we stop at the first step of this process – revenue requirement – because the remand orders suggest no change in rate spread and design determinations.

II. Regulatory and Ratemaking Context

Q. What is the overarching regulatory policy that guides the Commission in this remand proceeding?

A. All of the Commission's decisions and choices are guided by its delegation of authority from the Legislature, stated in ORS 756.040. That delegation contains two goals that relate to treatment of customers and two that relate to treatment of investors:

<u>Customers</u>

- Adequate service
- Fair and reasonable rates

<u>Investors</u>

- Returns commensurate with the returns on investments in comparable businesses
- Confidence in financial integrity, maintenance of credit and attraction of capital.

The delegation statute requires the Commission to "balance the interests of the utility investor and the consumer in establishing fair and reasonable rates." ORS 756.040. I believe this phrase is somewhat misleading to the extent that one could infer from it an opposition of investor and customer interests, with any gain to investors an equal loss to customers, and vice versa. Rather, the goals for customers and investors are inter-related and reinforcing: A utility cannot provide adequate service without the ability to attract capital. This is typically not in dispute in a rate-setting process.

For example, few would argue that a utility can attract capital if the rates set by the Commission do not allow it to pay the interest on its outstanding debt as such interest becomes due. Indeed, to borrow additional money on reasonable terms requires that a utility have the financial strength – created by the opportunity to earn and retain income over and

above interest payments – to make all future interest payments. Several credit rating agencies exist to inform potential lenders of the likelihood of repayment. The agencies' assessments influence access to and the cost of debt. Borrowing becomes significantly easier and less expensive when a firm has "investment grade" ratings. Accordingly, rate decisions that permit a utility to reach and maintain financial coverage ratios sufficient for investment grade debt ratings are usually not controversial. Above investment grade, however, the Commission must weigh the benefit to customers – in the form of reduced borrowing cost – with the cost to customers – in the form of higher rates today. It is this decision that is the balance between customers and investors.

Q. Is there another "balance" that is an important guide to ratemaking decisions?

A. Yes. The capital intensive nature of the utility business means that many of the costs incurred are large, lumpy expenditures for physical or intangible assets that produce benefits for many years. The Commission is constantly balancing the interests of today's consumer with the interests of tomorrow's consumer. To achieve the best allocation of society's resources over time, someone making the choice to use electricity today should pay roughly what it costs today, not significantly more and not significantly less. The Commission must spread costs fairly across "generations" of customers to achieve this result. It does so most often in the context of setting depreciation rates for all utility property, a task specifically given it by the Legislature. It engages in this balancing for other matters as well, such as amortization and accounting decisions.

This balancing of consumer interests across time relates to the balancing between consumer and investor interests. Rates set too low today to attract capital will make future

capital costs – and, thus, future rates – higher and may cause degradation in future service. Current customers will benefit at the expense of future customers.

Q. Are there any rules regarding how the Commission engages in both balancing investor and consumer interests and balancing consumer interests across time?

A. Very few. The statute at the heart of this remand is one of those few. In general, the Commission has broad discretion to fashion the balances that it finds most suitable to the facts at hand. This excerpt from the UE 88 order is typical:

> "Staff notes that the Commission has broad discretion when it comes to ratemaking. As the Oregon Supreme Court said, 'The [Commission] appears, therefore, to have been granted the broadest authority – commensurate with that of the legislature itself – for the exercise of [its] regulatory function.' *Pacific N.W. Bell v. Sabin*, 21 Or App 200, 214 (1975)." Order No. 95-322 at 61.

The Legislature's – and, thus, the Commission's – authority is constrained only by the Constitution. The seminal case of <u>Federal Power Commission v. Hope National Gas Co.</u>, 320 U.S. 591 (1944) explained that the constitutional protections are tested against the end result of a rate order. A later Supreme Court case – <u>Duquesne Light Co. v. Barasch</u>, 488 U.S. 299 (1989) – explained the "end result" test as follows:

> "[I]t is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unreasonable judicial inquiry is at an end. The fact that the method employed to reach that result may contain infirmities is not then important." 488 U.S. at 310

Worth noting is <u>Duquesne's</u> finding that state ratemaking authority cannot "arbitrarily switch back and forth between methodologies in a way which [requires] investors to bear the risk of bad investments at some times while denying them the benefit of good investments at other times" without raising serious constitutional questions. <u>Duquesne</u>, <u>supra</u>, 488 U.S. at 315.

Any exercise of the Commission's broad discretion as it sets rates, within its statutory delegation and subject to the U.S. Constitution's requirements on the end result, will have consequences for the future. The objective of regulatory policy is to find that exercise of discretion the consequences of which move the Commission closer to, not farther away from, its overarching goal of securing adequate utility service for consumers at fair and reasonable rates. To simplify its task, the Commission adopts certain frameworks and conventions.

Q. What do you mean by frameworks?

A. Integrated resource planning (IRP), or least cost planning (LCP) as it was known when the Commission first issued the order adopting it, is an example of a framework - and a very important one to consumers generally and to this proceeding. In 1988, the Commission determined that the process by which a utility chose its generating resources was a critical component of whether the Commission could find rates based on those decisions to be fair and reasonable. In particular, the Commission found that allowing public review of and input to utility resource decisions would improve the quality of such decisions. The Commission acknowledges resource decisions using the IRP framework and such acknowledgements affect subsequent ratemaking decisions. "Although a decision made in the LCP process does not guarantee favorable ratemaking treatment, the process should provide some guidance to a utility." Order No. 89-507 at 3.

Q. What do you mean by "conventions?"

A. By the term "convention," I mean "the way we usually do things unless there is good reason, determined by the Commission's overarching goal, not to." The use of cost as the basis of setting rates is a convention. Nothing requires that the Commission use cost. But it

is hard to think of a basis to use for ratemaking that is easier to determine and understand than cost and, thus, typically, economic regulation relies on cost. The choice of a test period over which to assess costs and revenues for purposes of determining rates is a convention.

Calculating interest costs and equity costs (net income) on the basis of rate base is also a convention. For some water utilities, this does not work at all because the utility plant they use is fully depreciated. In those instances, the Commission does not use rate base to determine the cost of debt and equity for rate-setting. Including purchased power in revenue requirement at the cost of the contract is another convention.

If any of these conventions has consequences that move the Commission further away from its goal of adequate service at fair and reasonable rates, the Commission has the broad discretion – noted above – to change the convention. A good example of this is the policies the Commission adopted in the early 1990s to encourage utilities to acquire demand-side resources – customer energy efficiency measures – to help offset future needs for generation. Mr. Dahlgren, PGE Exhibit 6100, Section II, discusses these policies.

These conventions not only change over time, but there is considerable diversity of conventions across regulatory jurisdictions. How one jurisdiction calculates various costs for ratemaking purpose may differ significantly from the conventions used in another jurisdiction. None of the variations are wrong; they are simply different.

Q. Is there a convention that particularly requires examination in this proceeding?

A. Yes. In Docket DR 10, the Commission developed the convention that it would use in setting rates for a utility that had retired a generating plant to achieve least cost power supplies for its customers. In brief, this convention was that a utility could recover its un-depreciated investment in a generating plant retired prior to the end of its nominal

depreciation life, if it established six facts and met six conditions designed to permit a conclusion that the retirement produced a "net benefit" for customers. Mr. Dahlgren describes the convention in PGE Exhibit 6100, Section III. The Commission applied this convention, with some refinement and further detail, in UE 88. The primary refinement of UE 88 was the conclusion that the net benefits test would consider the costs and benefits of retiring and replacing the output of that generating plant from a ratemaking perspective in addition to a planning perspective. The ratemaking perspective, eliminated from the calculation future costs found to be imprudent.

In developing this convention, the Commission assumed that it could set rates to include a return on any un-depreciated balance of the retired generating plant that the Commission did not allow the utility to recover immediately. The Commission did not contemplate that its decision regarding how to spread the un-depreciated plant costs to customers over time could also result in harm to utility investors. The net benefits calculation did not account for this; nor did the Commission's six conditions. Because of the Court of Appeals ruling, the Commission must develop, and apply, a new convention for the recovery by a utility of its remaining investment in a generating plant that it retires before the end of the plant's original depreciation life to achieve least cost for customers.

Q. How do the "overarching regulatory policy," frameworks and conventions you have discussed relate to PGE's position in this remand proceeding?

A. PGE's position rests on the assumption that, in this remand proceeding, the Commission will exercise its discretion regarding:

- The application of ratemaking conventions,
- Decisions on factual issues, and

- Policy choices

to achieve the overarching goal of regulatory policy and continue to support the frameworks – including IRP – it has developed. According to the Court of Appeals, the Commission may not set rates based on calculations that include return on the un-depreciated investment in an economically-retired plant that is being recovered over time, but the Legislature does not otherwise direct how the Commission should have set rates in UE 88 or UM 989. The overarching regulatory policy set forth in the Commission's delegation of authority applies and the Commission has broad discretion in how it exercises that authority.

Q. Is there anything unique about this proceeding?

A. Yes, the remand nature of this proceeding makes it unique. The Commission is not setting rates that will be in effect in 1995. Nor is it setting rates that will be in effect in 1996, 1997, 1998, 1999, or 2000. Instead, the Commission is engaged in setting rates for periods in which those rates cannot possibly take effect. Neither PGE nor customers can change past decisions that were made on the basis of these rates. The ratemaking decisions the Commission makes here can take effect only in the future. Based on the policy and future rates that emerge from this proceeding, PGE and its customers can only affect future decisions.

III. PGE's Approach

Q. What approach did PGE follow in reaching your position in this remand proceeding?

A. We applied three questions to serve as the criteria by which we could test the regulatory policy strength of our position. Then we identified the factual and policy decisions made in UE 88 that require re-examination in light of the Court of Appeals interpretation of Oregon law. Our position is a set of changes that best meets the criteria.

Any rate decision is the sum of a myriad of interconnected, factual, and policy decisions. It is hard enough to steer such decisions to rates that meet statutory and constitutional tests and produce consequences that work toward achieving the overarching goal of regulatory policy in the future when in a normal general rate proceeding. A retrospective review such as this only increases the difficulty. In such circumstances, developing and applying criteria helps discipline and manage the large number of possible paths.

Q. What criteria did PGE develop for this proceeding?

A. We believe that, had the Commission known in deciding UE 88 and subsequent cases that, if it spread the recovery of Trojan's un-depreciated balance over time, then it could not allow PGE to earn a return on the balance, its factual and policy decisions in UE 88 and ultimately UM 989 would have been guided by the answers to these questions:

1. Does this decision encourage electric utilities to analyze and make resource decisions that will yield "an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"[2]
2. Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears

[2] OPUC Order No. 89-507, page 2.

an inequitable burden of the costs or receives an inequitable share of the benefits?

3. Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

Q. Please explain the first criterion: Whether this decision encourages electric utilities to analyze and make resource decisions that will yield "an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest."

A. First and foremost, this criterion recognizes the importance to Oregon of least cost planning. As Mr. Dahlgren explains, the IRP process is designed to produce least cost resource decisions, over time, for customers. At times, achieving the least cost set of resources for customers may require not only the addition of new resources but the retirement of some existing resources, the incremental costs of which exceed the costs of replacements. The Court of Appeals interpretation has created a barrier to such least cost resource realignments, however. If a utility cannot earn a return on the plant that it has retired to achieve least cost for customers, and the Commission does not allow the utility immediately to recover the remaining plant investment so that the utility's investors remain whole, then it has little incentive to take this resource action. The action would produce negative results for the utility, rather than positive or even neutral results. The disincentive worsens if the Commission does not otherwise set rates to allow a utility in this situation the revenues sufficient to maintain its financial health and credit ratings over time. Oregon utilities would be motivated to continue operating resources for their nominal depreciation lives, rather than their economically useful lives, as measured by least cost to customers over time.

This incentive would work against the least cost planning framework that is so important to achieving safe and adequate service for customers at reasonable rates.

The first criterion also recognizes the soundness of a regulatory approach that encourages utilities to act in the interests of customers and the public, rather than punishing them for not doing so. Mr. Dahlgren discusses an example of such encouragement: the set of policies the Commission adopted to encourage utilities to invest in demand-side resources (energy efficiency). PGE Exhibit 6100, Section II. Instead of adopting these policies, the Commission could simply have told utilities it would disallow any supply-side costs it determined the utility could have avoided by investing in demand-side resources instead. The difficulties with the punitive approach, however, are several. First, it is much easier to identify and reward affirmative actions a utility has taken. Such actions require no speculation. They are measurable. Second, too much use of cost disallowance can threaten a utility's financial integrity and ability to attract capital on reasonable terms, and thus threaten the Commission's ability to achieve the goal of adequate service at fair and reasonable rates in the future. Last, based on my experience observing the effects of regulatory choices over 20 years, rewards can motivate even at the individual level. Rewards encourage individual actions, because individuals can understand how their actions will help the utility achieve better financial results and may be mirrored by individual incentive programs. Utilities cannot so align individual financial results with disallowances.

Q. Please explain the second criterion: Whether this decision equitably allocates the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable burden of the costs or receives an inequitable share of the benefits.

A. This criterion expresses the balance of customer interests I discussed in Section II of my testimony. It is a well-understood principle of economics that consumers will make the best decisions about consumption if the price paid for such consumption at any given time is as close to the true cost as possible. A significant misalignment of costs and benefits of a utility resource decision would violate this economic principle. The Commission routinely applies this criterion in determining the period over which utilities will recover the cost of assets (depreciation or amortization) and expenses (e.g., debt refinancing costs) incurred to produce future benefits, as well as the period over which customers will receive the benefit of utility cost savings (e.g., lower than expected variable power costs) or revenue credits (e.g., sales for resale, property sale gains).

Q. Please explain the third criterion: Whether this decision preserves the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised.

A. As with the first two, this simply states as an explicit question matters I discussed in Section II. Although aspects of this criterion relate to constitutional requirements, it has practical implications for customer needs as well. All investors, debt or equity, care about the regulatory environment into which they are investing. Regulatory policies that are understandable, fair, and focused on the long-term, decrease the perceived investment risk. For example, investors perceive as understandable and fair regulatory policies that allow recovery of prudently-incurred costs. Regulatory policies that put prudently-incurred costs at risk to events or outcomes outside of the utility's control would be perceived the opposite. Decreased risk increases the availability of capital and decreases its cost; increased risk has

the opposite effect. Thus, this criterion is important for investors and customers over time. What appears cheap today may be costly tomorrow.

Q. Are there any other considerations that are important guides to ratemaking decisions?

A. Yes. As a general matter, customers value and Commissions work to achieve rates that are relatively stable over time, with predictable movement. For example, customers typically would prefer a series of small increases, anticipating higher costs over time, than a larger one-time increase. Many consumption decisions relate to equipment or processes that are hard to adjust immediately but that a customer can modify if given some time to do so. For example, assume a large business customer with significant capital investment in equipment and complex manufacturing processes. This customer may be able to reduce its energy consumption over time through changes to equipment, processes or both but it probably cannot make such changes quickly in response to a one-time large increase in the cost of electricity. Spreading such an increase over time in rates that anticipate the higher costs that are coming allows customers to make such equipment and process changes. Achieving rate stability and predictability need not harm customers or the utility as long as the Commission recognizes in setting rates the time value of any rate changes not exactly aligned with the underlying cost changes.

IV. Building Blocks

Q. Please summarize the UE 88 factual and policy decisions PGE is suggesting the Commission might have made differently had it known of the Court of Appeals ruling.

A. The factual and policy decisions we are suggesting the Commission might have made or made differently are the following:

- The period over which it ordered PGE to amortize its un-depreciated Trojan investment (Subsection A);
- The required return on common equity and capital structure (Subsection B);
- The calculation of the net benefits test and application of the resulting net benefit (Subsection C);
- The classification of certain components of Trojan as plant-in-service (Subsection D);
- The amortization period for certain liabilities on PGE's balance sheet owed to customers as of March 1995 (Subsection E);
- The recovery in 1995 of all forecasted 1995 net variable power costs (Subsection F); and
- The inclusion in rates of all of PGE's interest payment costs, regardless of whether the underlying debt relates to un-depreciated Trojan investment (Subsection G).

For each of these factual or policy decisions, I discuss below why the Commission should revisit it, and the outcome or range of outcomes PGE believes the Commission would have adopted and why, including the reasons for changing a ratemaking convention if necessary.

A. Amortization Period

Q. Why should the Commission revisit its decision in UE 88 regarding the period over which PGE should amortize its un-depreciated investment in Trojan?

A. The Commission should revisit this amortization decision because it relies completely on the Commission's assumption that it could allow PGE to recover its costs of equity and debt capital associated by allocating to customers over time the un-depreciated investment. The Court of Appeals ruling that the Commission could not allow PGE a return on the Trojan investment requires that the Commission revisit the period of amortization.

Applying the simple principle that a dollar received in the future is not worth the same as a dollar received today, any delay in PGE's receipt of this investment is a quantifiable decrease in the investment for which the Commission would be granting recovery. The PGE Panel[3] calculated that leaving the amortization period for Trojan's un-depreciated investment at 17 years without a return is the same as an initial disallowance of $182 million. PGE would have experienced an asset write-off of $149 million, lowering its retained earnings in 1995 from $136 million to $46 million.

Q. How was the amortization period for the un-depreciated balance of Trojan investment chosen?

A. The amortization period chosen resulted from the application of ratemaking convention, although the Commission did not discuss this explicitly. If a utility incurs a particular cost to produce a benefit such as lower future costs, the Commission typically sets the amortization of the up-front cost over the period that customers will experience the lower costs. Examples

[3] The PGE Panel is Jay Tinker, Stephen Schue, and Patrick Hager who prepared and appear in PGE Exhibit 6200. That exhibit provides the quantitative analysis PGE is presenting in this docket, other than that quantification done in support of return on equity.

of this convention include the Commission's treatment of amounts incurred to replace higher cost debt with lower cost debt, and its recent decision on treatment of costs incurred to reserve natural gas pipeline space at a low price for eventual use by Port Westward. Order No. 95-322 reflects this convention in its choice of the same period for amortization of Trojan as the 17-year period of the cost-benefit analysis supporting Trojan's closure.

Q. Does good reason exist to change this convention here?

A. Yes, good reason exists for the Commission to shorten the recovery period. As noted above, a 17-year amortization period under the Court of Appeals interpretation of Oregon law results in a disallowance to PGE of $182 million and a write-off of $149 million. Mr. Hager testifies regarding the negative effects this outcome would have had on PGE's ability to attract capital and cost of capital. (PGE Exhibit 6400, Section III). As I discuss in Section IV.E. below, the Commission could have exercised its discretion regarding other elements of ratemaking to achieve the same inter-generational result for customers as the 17-year amortization period achieved but avoid this large financial loss to PGE.

Q. What amortization periods should the Commission consider in deciding this remand proceeding?

A. The Commission should consider a one-year amortization period. We believe it most likely that, had the Commission decided to select a rapid recovery, it would have chosen a one-year period. To prevent any diminution in the amount of un-depreciated investment the Commission found that PGE should recover, the collection period would have needed to be one day. This is not practical. Nor would a one-day recovery be fair between customers, whose usage as of that day may be other than their normal usage. One year captures the

monthly and seasonal variations in customer usage and roughly allocates the cost according to usage patterns.

Q. What outcome or range of outcomes results from revisiting the decision regarding amortization of PGE's un-depreciated Trojan investment?

A. A decision regarding the amortization period for PGE's un-depreciated investment in Trojan affects the UE 88, UE 93, and UE 100 rate periods as well as UM 989. Briefly, a one-year amortization would significantly increase the UE 88 and UE 93 (first four months) revenue requirements and lower revenue requirements in the last part of the UE 93 rate period and during the entire UE 100 rate period. In 2000, PGE would have had no un-depreciated Trojan investment on its balance sheet. On the other hand, the large disparities in rates across the rate periods would require that the Commission evaluate whether the UM 989 result remains reasonable. One method of doing so would be to compare the amounts owed PGE from the UE 88 and first part of the UE 93 rate periods to amounts owed customers from the last half of the UE 93 and UE 100 rate periods. Using this method, the net present value difference in amounts owed PGE and amounts owed customers supports the stipulations approved in UM 989. The PGE Panel details these outcomes in PGE Exhibit 6400, Section II.

B. Required Return on Equity and Capital Structure

Q. Why are you suggesting that the Commission might have made a different decision with respect to the level at which it established PGE's required return on equity (ROE) in UE 88?

A. The Commission's delegation of authority from the Legislature requires that it, among other things, establish a return to the equity holder that is commensurate with the return on investments in other enterprises having corresponding risks. Both when the Commission decided UE 88 and now, few utilities faced or today face the risk of a major loss to their equity holders caused by the early retirement of a generating plant to produce net benefits for customers. PGE's investors face more risk than their counterparts and, thus, PGE's cost of capital is likely higher than for comparable utilities that do not face such a regulatory environment. See generally Makholm and Blaydon, PGE Exhibits 6500 and 6600. The Commission would have considered this greater risk in determining PGE's required return on common equity in UE 88, UE 93, and UE 100.

Q. Was the Commission's determination of PGE's required return on equity in UE 88, UE 93, or UE 100 the result of a convention?

A. No. To determine required return on equity, the Commission typically relies not on convention but on economic models, such as the discounted cash flow (DCF) or capital asset pricing (CAPM) models.

Q. What required return on common equity should the Commission consider in deciding this remand proceeding?

A. PGE Exhibit 6400 supports increases in PGE's required return on equity ranging from 25 to 150 basis points. A basis point is one-hundredth of a percent. The lower end of the range represents the increased risk to investors in Oregon utilities related to the Court of Appeals interpretation of Oregon law and a short amortization period. The higher end of the range relates to risk investors would perceive if the system of economic regulation in Oregon forced utilities to receive, over an extended period with no return on investment, their un-

depreciated investment in generating plants economically retired before the end of their depreciation lives.

Q. What outcome or range of outcomes results from re-determining PGE's required return on equity?

A. Applying the range to UE 88, UE 93, and UE 100 results in revenue requirements $17 million to $102 million higher than the Commission would otherwise have found. The PGE Panel demonstrates this at PGE Exhibit 6200, Section III.

Q. Does similar reasoning underlie your suggestion that the Commission might have, for purposes of ratemaking, established a different capital structure for PGE?

A. Yes. The Commission's delegation of authority also requires that the rates be sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital. Although a higher ROE that provided PGE an opportunity for greater net income would contribute to financial integrity, use of a hypothetical capital structure with greater amounts of equity would also accomplish this result.

Q. Was the Commission's determination of capital structure for PGE in UE 88, UE 93 and UE 100 the result of applying a convention?

A. Yes. Historically, the Commission has used a utility's actual capital structure during the one-year test period it is using to set rates, if this is known. In other words, for a utility such as PGE, the Commission would use PGE's forecast capital structure for the test year. Sometimes the Commission cannot know a utility's actual capital structure for utility service because the utility has significant non-utility activities within its business structure. In such cases, the Commission has used a hypothetical capital structure.

Q. Does good reason exist to use a hypothetical capital structure for PGE during the UE 88, UE 93, and UE 100 rate periods, rather than the actual capital structure used by the Commission in its initial decisions?

A. Yes. Depending on the other decisions the Commission decides that it would have made. As Patrick Hager explains in PGE Exhibit 6400, Section III, a Commission decision to amortize Trojan's un-depreciated balance over 17 years would significantly worsen the financial ratios by which credit rating agencies decide whether a utility is credit-worthy. A hypothetical capital structure could help restore the ratios to levels that will help attract future capital. PGE Exhibit 6401.

Q. What outcome or range of outcomes might result from re-visiting this issue?

A. Use of a hypothetical capital structure with greater amounts of equity would increase UE 88, UE 93 and UE 100 revenue requirements, all else being equal. The PGE Panel does not quantify these outcomes because they are similar to the outcomes PGE quantifies for a higher required return on equity.

C. Calculation and Application of Net Benefits

Q. Which factual and policy decisions in the calculation of the net benefits test are you suggesting that the Commission revisit and why?

A. PGE suggests that the Commission revisit in this remand proceeding one factual and one policy decision included in the UE 88 calculation of the net benefits test.

The factual decision relates to costs included on the replacement resources side of the net benefits test comparison. In the UE 88 calculation of the net benefits test, the Commission included recovery by PGE of our Trojan investment over 17 years, with a return on the un-

depreciated balance, matching the recovery of and return on Trojan assuming continued operation. Under the Court of Appeals interpretation, this must change. As explained above (and, in more detail in PGE Exhibit 6200, Section IV), whether amortization of the un-depreciated balance is over one year or 17 years, excluding any return on investment effectively reduces the cost to customers, and thus increases the benefit of closure. All else being equal, this will lower the cost of the replacement resources side of the net benefits test, increasing the net benefit to closure. The PGE Panel calculates that adjusting the net benefits test for the Court of Appeals interpretation results in a net benefit for closure of $-4 million assuming a one-year amortization period and $155 million assuming a 17-year amortization period. This adjustment is consistent with and required by the Commission's methodology.[4]

The policy decision relates to costs included on the continued operation of Trojan side of the net benefits test comparison. In UE 88, the Commission exercised its discretion to exclude from the costs of Trojan's continued operation amounts PGE would have incurred to replace Trojan's steam generators. This exclusion did not rely on any finding of imprudence by PGE; indeed, the Commission explicitly found that PGE had acted prudently with respect to both the purchase and maintenance of the steam generators that would require replacement. Order No. 95-322 at 3. Nor did the Commission find that PGE could have operated Trojan for its remaining license life without new steam generators. Nonetheless, the Commission ultimately decided in the context of UE 88 to allocate the consequences of the steam generators' problems to PGE, stating that:

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[4] As Order No. 95-322 explains, the net benefit test is a scenario comparison: the future costs of continued Trojan operation compared to the future costs of other resources. Footnote 16 on page 32 of that Order states: "Under the net benefits analysis, sunk investment cost is added to the cost of each option. . . . . The net benefit treatment of sunk investment cost does not . . . change the difference between the costs of any two options . . . ." Had the Commission known of the Court of Appeals decision, it could not have made this statement.

> "Although PGE's behavior was not faulty, PGE and the ratepayers are the only two parties to whom we can assign or impute steam generator costs. As between those two parties, PGE is better situated to recover its costs from the manufacturer of the steam generators. Moreover, it is fair that shareholders bear some of the consequences of management investment decisions." Order No. 95-322 at 3.

Order No. 95-322 is clear that the Commission's decision to exclude the steam generator replacement costs from the continued operation scenario in the net benefits test was an exercise of its discretion. It noted PGE arguments against the exclusion and emphasized that its decision on cost recovery was not meant to act as precedent for any future outcome.[5]

We suggest here that, had the Commission known that the Court of Appeals would interpret ORS 757.355 to prohibit rates that included a return on the remaining Trojan investment, the Commission might not have exercised its discretion on this issue as it did. It might not have found it "fair" to allocate this cost to shareholders. No convention dictated the original result and none inhibits a different decision now. Indeed, good regulatory policy supports reversing this UE 88 decision. Holding investors solely responsible for prudently incurred costs shifts significant risk to such investors. As Dr. Makholm explains, (PGE Exhibit 6500) one of the most fundamental investor expectations about a regulator is that the regulator will allow the utility an opportunity to recover prudently incurred costs through its rate decisions. The UE 88 net benefits test decision on the steam generators violates this expectation, raising questions for the future, even though the Commission attempted to minimize the effect by stating it would make such decisions on a case-by-case basis. Given the risk that the Court of Appeals interpretation has added to Oregon's regulatory environment, it makes little sense to

[5] Subsequent to UE 88, PGE resolved its claims against Westinghouse. The settlement of that litigation resulted in a payment of about $4 million by Westinghouse, which PGE credited to customers in the UM 989 stipulation. The $187 million excluded by the Commission from the net benefits test dwarfs the amount PGE was ultimately able to recover from the manufacturer.

add more risk by preserving this decision to exclude steam generator replacement costs from the net benefits test calculation.

Q. Might the Commission have made different decisions regarding other inputs to the net benefits test used in UE 88?

A. Yes. Order No. 95-322 discusses and resolves a number of inputs to the net benefits test for which competing views were presented. Most of the Commission's decisions chose inputs that lessened the amount of net benefit created by early retirement, creating a conservative result. Were the Commission to revisit any of these decisions, the amount of net benefits from retirement would increase. Although PGE is not presently suggesting that the Commission needs to engage in this retrospective review of the disputed inputs to the net benefits test, we ask that the Commission recognize the conservative quality of the original net benefits result in determining how to apply the net benefits result in this remand proceeding.

Q. What is the effect on the result of the net benefit test of the factual and policy decisions you suggest that the Commission re-visit?

A. Adding the steam generators to the cost of continued operation increases the net benefits of closure by $183 million, all else being equal. With both changes I discuss above, the PGE Panel estimates net benefits ranging from $179 million, assuming one-year amortization of Trojan's un-depreciated balance, to $338 million assuming 17-year amortization.

Q. Why should the Commission revisit its application of the result of the net benefits test?

A. The Commission should revisit the result of its application of the net benefits test because, in UE 88, it considered only how it might apply a negative net benefit. The factual and policy decisions made in calculating net benefits for UE 88 resulted in a negative net benefit of $27

million (pre-tax).[6] Thus, the Commission's regulatory policy analysis considered the net benefits test only in the context of "a tool to determine where ratepayers are held harmless for imprudent operation or management of Trojan, and to share costs between ratepayers and shareholders on that basis." Order No. 95-322 at 2.

Order No. 95-322 does not discuss how the Commission might have exercised its discretion had the result of the calculation of the net benefit test been the positive $179 million to $338 million I note above. These are significant net benefits to customers that the Commission would want to encourage utilities to look for, even with the ruling that investors cannot receive a return on generating plants economically-retired before the end of their depreciation lives to achieve least cost for customers.

Q. What applications of a positive net benefit calculation should the Commission consider in this remand proceeding and why?

A. The Commission should consider two applications of a positive net benefit calculation in this proceeding. First, it should consider reversing the disallowance of a portion of Trojan's un-depreciated balance. This decision rests entirely on the factually-derived negative outcome of the net benefits test. The Commission found a negative net benefit to closure of $27 million in UE 88 and ordered a corresponding disallowance to PGE's un-depreciated Trojan investment. A positive net benefit requires reversal of the $27 million disallowance.

Second, the Commission should consider whether, to encourage future analysis and implementation of early plant retirements that are in the public interest and under least cost planning principles, a "share-the-savings" mechanism could be appropriately applied to the calculated net benefit. The Commission approved a similar mechanism in connection with

[6] The after-tax number was $20.4 million.

another outcome of least cost planning: the acquisition of energy efficiency resources by utilities. In Order No. 91-98, the Commission adopted the SAVE program for PGE. This program, which was designed to "motivate PGE to aggressively pursue cost-effective energy efficiency measures," included a financial incentive for energy efficiency investment. As the Order explains:

> "The incentive component of the SAVE proposal allows PGE to earn revenues in addition to the allowed rate of return on capital investment over a period of 15 years. It provides for a sharing of the savings from non-use of electricity based on the value of verified energy efficiency savings that exceed benchmark levels." Order No. 91-98 at 3.

The SAVE incentive component is an instance of the Commission departing from the convention of basing rates on direct costs of electricity service. When necessary to promote important policies, such as the least cost planning framework, the Commission has discretion to depart from such conventions.

Q. What outcome or range of outcomes would result from the Commission revisiting its application of the net benefits test, restated for the revised calculations?

A. I addressed above the restoration of the $27 million disallowed from Trojan's undepreciated balance.

With respect to a share-the-savings mechanism, any number of models exists. The SAVE mechanism ultimately resulted in an incentive payment of over 50 percent of the amount PGE invested in demand-side resources over the three-year period 1991 through 1994. The power cost adjustment (PCA) in place from the late 1970s to 1987 gave PGE 20 percent of the savings achieved from a quarterly-updated baseline net variable power cost. In UE 47/48, the Commission allocated to PGE 23 percent of the gain PGE created by selling a portion of our Boardman generating plant with an accompanying long-term power

purchase agreement.[7] For purposes of creating building blocks to use in this remand proceeding, we chose the 20 percent incentive of the PCA design.

The PGE Panel calculates that reversing the disallowance and adding a share-the-savings incentive increases revenue requirements across UE 88, UE 93 and UE 100 by $17 million.

D. Plant Classification

Q. Why are you suggesting that the Commission revisit its UE 88 decision regarding classification of Trojan's assets between plant-in-service and un-recovered plant accounts?

A. The Commission should revisit its decision regarding the classification of Trojan assets between plant-in-service and unrecovered plant because, as with its decision regarding an amortization period for un-depreciated Trojan investment, it relied on the assumption that it could allow PGE to recover its costs of capital regardless in which account PGE recorded the assets (Order No. 95-322 at 53). In other words, as the law stood when the Commission made this decision in UE 88, the decision made no practical difference.

In UE 88, the Commission acknowledged "that there is no prescribed method of accounting for nuclear plants that are in the process of being decommissioned." Based on evidence PGE presented in UE 88 and PGE Exhibit 6300, Quennoz-Peterson-Dahlgren, the Commission should find that certain Trojan assets remained in utility service to protect public safety and support decommissioning activity. The Commission may set a return of and on assets that remain in service. These assets are not subject to the Court of Appeals interpretation restricting the Commission's discretion to set rates by precluding a return on

[7] Order No. 87-1017 at 30.

assets that no longer provide service.

Although Order No. 95-322, at p. 54, cites FASB[8] Statement 90 as supporting the classification of assets to un-recovered plant, this provides limited guidance because one first must decide what "asset" is being abandoned. PGE was not abandoning any component of Trojan that remained necessary to protect public safety or enable government-required decommissioning work. These assets remained in service. An electric utility has many assets and components of assets not directly involved in generating or delivering electric energy. Fish ladders at hydro-electric generating plants and fences at substations are two examples. These facilities are used and useful to accomplish their utility service purposes and would remain so even if the hydro-electric plant or the substation were no longer in use to generate or distribute electricity.

Q. What outcome or range of outcomes could result from revisiting this decision?

A. Stephen Quennoz, Pete Peterson and Randy Dahlgren, PGE Exhibit 6300, support the analysis PGE presented in UE 88 that showed $80 million in un-depreciated Trojan investment remained in utility service following the closure decision. The PGE Panel calculates that, all else being equal, the proper classification increases revenue requirements in UE 88, UE 93 and UE 100. It also increases the un-depreciated balance remaining at the time of UM 989 even if the Commission chose a one-year amortization period for the un-depreciated investment that did not remain plant-in-service because these in service assets would have remained on the original 17-year depreciation life.

[8] FASB stands for Financial Accounting Standards Board.

E. Amortization Periods for Certain Customer Credits

Q. Are there amortization periods for balance sheet items other than Trojan that the Commission should consider?

A. Yes. PGE's 1995 balance sheet included a customer credit for the gain achieved in the 1985 sale of a portion of the Boardman plant. The Commission set a 27-year amortization period for that credit in UE 47/48. Order No. 87-1017 at 30. In UE 88, the Commission left the Boardman gain amortization period unchanged but, in UE 93, it accelerated these credits to use as offsets to several amounts customers owed PGE, including the AMAX termination payments, power costs deferred in several years, and the SAVE incentive PGE had earned. The Commission should, on remand, offset the remaining Boardman gain against an equal amount of un-depreciated Trojan investment before setting UE 88 rates. This would require that the Commission also establish amortization periods for AMAX, the deferred power costs, and SAVE in UE 93.

Q. Why should the Commission revisit this policy decision?

A. The reason why the Commission should revisit its policy decision to leave Boardman on a 27-year amortization schedule depends on the amortization period it decides is appropriate for PGE's un-depreciated Trojan investment in light of the Court of Appeals ruling.

If the Commission decides that a one-year amortization of Trojan is appropriate, accelerating Boardman's amortization would improve the matching of costs and benefits over time. Revisiting the amortization of Boardman improves the inter-generational equity associated with allowing PGE to recover its un-depreciated investment entirely from one year's customers, while customers would receive the benefits of such closure over at least 17 years.

If the Commission decides that a 17-year amortization of Trojan remained appropriate, accelerating amortization of the Boardman gain lessens the negative impact of the Trojan decision on PGE's financial integrity and ability to attract capital. Allowing PGE to offset the amounts owed customers for the Boardman gain with the amounts owed its investors for Trojan in effect allows PGE to recover some of the outstanding balance in one day. Although a one-day recovery is impracticable as a ratemaking matter, it is not impossible if accomplished as a netting of balance sheet entries. Because PGE would have experienced no loss of the time value of money associated with the amount of Boardman gain so applied, our write-off would have been less: $98 million rather than $149 million.

Q. Was the amortization period chosen for the Boardman gain the result of applying a ratemaking convention?

A. No. The amortization period for a credit to customers such as the Boardman gain is entirely within the Commission's discretion and should serve regulatory policy. No specific conventions exist. In the 1987 general rate case, UE 47/48, the Commission set the Boardman gain on a 27-year amortization schedule to match the period customers would have received such amounts had the sale of the plant been only a power sale instead of an asset sale accompanied by a power sale. The Commission found reason to depart from this rationale in November 1995, for UE 93. We suggest that, in light of the Court of Appeals interpretation, good reason now exists to shift that reconsideration of the Boardman amortization period from November to March 1995.

Q. What is the outcome of revisiting this decision?

A. Applying the remaining Boardman gain to reduce the un-depreciated Trojan investment available for ratemaking has various effects on the UE 88, UE 93 and UE 100 rate periods

and on the un-depreciated balance remaining at the time of UM 989. These effects depend on the combination of other building blocks assumed. Generally, applying the remaining Boardman gain to reduce the Trojan balance reduces the lost economic value resulting from collecting Trojan with no return over any assumed amortization period.

F. Recovery Timing of 1995 Net Variable Power Costs

Q. Why are you suggesting that the Commission revisit the timing of recovery of PGE's 1995 net variable power costs?

A. Revisiting this policy decision may be appropriate if the Commission decides that, on remand, the UE 88 amortization period for PGE's un-depreciated Trojan investment should be one year.

In UE 88, the Commission followed the standard ratemaking convention of setting rates to recover current costs, including net variable power costs. The Commission departs from this convention, however, when good reason exists to do so, such as a temporary and material rise in power costs. The first nine months of 2001 were a good example of this. In such cases, the Commission sets aside a portion of the current incurred costs for later recovery. The Commission spread the 2001 excess power costs over a period of almost 4 years, from 2002 through 2005. Among other purposes, this practice improves rate stability and predictability by smoothing unexpected lumpiness in costs.

If the Commission decided, on remand, that PGE should amortize its Trojan investment over one year, the total revenue requirement of current power costs and Trojan recovery would be temporarily high. In these circumstances, deferring a portion of current 1995

power costs for recovery in subsequent years would simultaneously improve the matching of the costs and benefits of the Trojan closure decision and increase rate stability.

Q. Was the inclusion of all of the 1995 forecasted net variable power costs in rates the result of applying a ratemaking convention?

A. Yes. As I explained above, the Commission typically considers, in setting rates for a given rate period, all of the costs the utility expects to incur to provide service during that period.

Q. Does good reason exist to change this convention here?

A. Yes, good reason exists if the Commission also decides that, in UE 88, it would have set the amortization period for PGE's un-depreciated Trojan balance at one year. The one-year increase and subsequent decrease in rates resulting from the Trojan amortization decision would have created rate instability, affecting customers' ability to make sound economic decisions regarding their use of electricity. In addition, the one-year period would not have matched the costs of achieving the net benefits of Trojan's closure with customers' receipt of those benefits. Deferring a portion of 1995 net variable power costs would help the Commission achieve this matching.

Q. What would be the outcome of revisiting this policy decision?

A. Revisiting this decision, in the context of a one-year amortization of un-depreciated Trojan investment, lowers UE 88 and four-months of UE 93 revenue requirements and increases subsequent revenue requirements. A significant amount of deferred power costs would have remained at the time of the UM 989 stipulation. The PGE Panel calculates the rate levels and balance sheet effects associated with this decision assuming that the Commission exactly offsets the un-depreciated Trojan investment with a power cost deferral. When

combined with other building blocks, the results of this assumption are provided by the PGE Panel. PGE Exhibit 6200, Section IX, Part B.

G. UE 88 Interest Costs

Q. Why do you suggest that the Commission, on remand, might include all of PGE's interest costs in rates, regardless of whether some of the debt related to un-depreciated Trojan investment?

A. We make this suggestion both on a legal basis, as explained in PGE's Pre-Trial Brief, Section V, Subsection H and because, from an economic perspective, it seems particularly unfair to claim that the prohibition of ORS 757.355 relates to the entire financing cost of the utility. Prohibiting an equity return requires that equity investors accept a zero return on their investment. However, forcing equity investors to pay the costs of debt financing imposes a further burden on equity investors and in fact requires that they accept a negative return to cover the contractual debt payments. In the case of Trojan, disallowing the debt and interest payments causes equity investors to lose approximately $41 million over the 5.5 years from April 1995 to September 2000 and $76 million over the full 17-year period in addition to the lost profit. PGE Exhibit 6201, Page 2.

Q. Would excluding both interest and profit related to un-depreciated Trojan investment be the result of applying a convention?

A. Yes. The Commission currently uses a specific rate times rate base – the term from the statute – to determine the basis for both a utility's interest costs and the cost of its common equity. This is the usual, although not the only, choice for common equity. But one can find the expected amounts of interest payments from a utility's accounts without regard to

rate base. Ultimately, the Commission is regulating to achieve an allowed return on equity and essentially a fixed component like O&M.

Q. Does good reason exist to change this convention here?

A. Yes. As with other factual decisions and policy choices I discuss above, applying this convention in UE 88 made no difference until the Court of Appeals interpretation. The Commission believed it could allow PGE to recover all of its capital costs – debt and equity – as well as its un-depreciated investment. This assumption is no longer valid. Applying this conventional way of calculating return will result in the penalty to equity investors explained above: not only will these equity investors lose their profit opportunity, but they will be required to cover the interest payments that must occur until the debt is retired.

We also note that some other jurisdictions (cited in PGE's Opening Brief), under similar but not identical circumstances, differentiated between the interest owed with respect to money borrowed for an uncompleted generating plant and the potential profit the utility would have made, denying the utility that potential profit but not requiring that the utility take a loss by absorbing the cost of the borrowed money.

H. Building Blocks Conclusion

Q. Are the above the only factual decisions and policy choices the Commission might have made differently in UE 88, had it known of the Court of Appeals interpretation?

A. No, they are not. It is impossible to know how knowledge of the Court of Appeals interpretation would have influenced the Commission's cumulative exercises of discretion in UE 88 as it strove to set rates that, in their end result, fell within the scope of its statutory

delegation, satisfied constitutional requirements and met the criteria I described in Section III. These are, however, the most obvious ones.

V. PGE's Position

Q. Please restate PGE's position from Section I of your testimony.

A. If the Commission had known that it could not establish rates including a return on un-depreciated balances of economically-retired generating assets even if it spread the recovery of such balances over time, then:

- In 1995, the Commission would have found fair and reasonable rates at least as high, if not higher, than the rates approved in Docket UE 88, Order No. 95-322; and
- In 2000, the Commission approved of the stipulations presented to it and the proposed $10 million rate reduction as fair and reasonable and a proper exercise of its discretion as a Commission in Docket UM 989, Order No. 00-601, because amounts owed PGE at that time would have exceeded the customer credits used as an offset. This would have provided economic as well as other benefits to customers from the resolution of the issues.

Q. What is the basis of your position?

A. We base our position on two sets of factual and policy decisions that we would have recommended in UE 88, either one of which we believe the Commission could and would have adopted. These sets of decisions meet the criteria I described above, although not to the same degree or in the same way.

Q. What is the first set of factual and policy decisions PGE would have requested that the Commission find in UE 88?

A. PGE would have requested, and believes the Commission reasonably would have found, that PGE should:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation and including the effects of the Court of Appeals ruling in the costs of closure and steam generator replacement in the costs of continued operation.
- Leave \$80 million of the Trojan assets in the plant-in-service accounts.
- Offset the \$111 million Boardman gain against the un-depreciated Trojan assets that were not still plant-in-service and amortize the remainder over one year.
- Be allowed a required return on equity of 11.85 percent.
- Defer a portion of its 1995 and 1996 (four-months, to match the period of Trojan recovery) net variable power costs, for recovery over the subsequent ten years.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs and SAVE incentive over the same ten years.

The PGE Panel (PGE Exhibit 6200, Section IX.B) presents the effect of these revised factual and policy decisions on UE 88, UE 93, UE 100, and UM 989. The results, summarized in Table 1 below, show that no refund is due for any rate period because the UE 88, UE 93, and UE 100 rates are all the same or higher than the rates in effect during those periods:

Table 1
(\$000)

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirements	Revenue Requirement Difference
UE 88	621,028	627,510	6,482
UE 93	1,003,794	1,011,340	7,546
UE 100	3,674,898	3,679,829	4,931

The results also show that sufficient assets existed on PGE's balance sheet as of 2000 to support the offsetting of amounts owed PGE, \$180 million, and amounts owed customers,

$161 million, per the stipulations the Commission exercised its discretion to adopt in UM 989.

Q. How does PGE's position comport with the criteria you presented in Section III?

A. Our position serves all of the criteria we presented above. I will address each separately.

Q. Please restate the first criterion and explain how PGE's position satisfies it.

A. Our first criterion uses the question:

> Does this decision encourage electric utilities to analyze and make resource decisions that will yield, "for society over the long run, the best combination of expected costs and variance of cost" to "assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"

PGE's position is at least neutral on this criterion. The use of a one-year amortization would have resulted in a $24 million write-off on PGE's balance sheet in 1995. This would not have been particularly encouraging, particularly when added to the $5 million additional write-off PGE took in connection with the UM 989 stipulations.[9] On the other hand, the higher required return on equity improves debt coverage and provides equity investors the opportunity for higher earnings. Also encouraging are the restoration of the previously-disallowed amount and the proper classification of assets necessary to protect public safety as utility plant in service.

Q. Please restate the second criterion and explain how PGE's position satisfies it.

A. Our second criterion uses the question:

> Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable

[9] These write-offs are additive to the $53 million pre-tax write-off ordered in UE 88.

burden of the costs or receives an inequitable share of the benefits?

PGE's position answers this question positively. No annual generation of customers over the period 1995 through 2000 would have borne an inequitable share of the costs of the least cost decision to close Trojan, nor received an inequitable share of the benefits.

Q. Please restate the third criterion and explain how PGE's position satisfies it.

A. Our third criterion asked the question:

> Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

PGE's position allows a positive answer to this question, for many of the same reasons as discussed under the first criterion.

Q. What is the second set of factual and policy decisions that PGE would have requested that the Commission find in UE 88?

A. PGE would have requested, and believes the Commission could reasonably have found that PGE should:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation and including the effects of the Court of Appeals interpretation in the costs of closure and steam generator replacement in the costs of continued operation.
- Receive 20 percent of the positive net benefit created through its economic retirement of Trojan, spread evenly over 17 years.
- Leave $80 million of the Trojan assets in plant-in-service accounts.

- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not still plant-in-service.
- Be allowed a required return on equity of 13.1 percent.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs and SAVE incentive over three years beginning with UE 88 rates.

The PGE Panel (PGE Exhibit 6200, Section IX.C)presents the effect of these revised factual and policy decisions on UE 88, UE 93, UE 100, and UM 989. The results, summarized in Table 2 below, show that no refund is due for any rate period because the UE 88, UE 93, and UE 100 rates are all the same or higher than the rates in effect during those periods:

Table 2
($000)

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirement	Revenue Requirement Difference
UE 88	621,028	621,090	63
UE 93	1,003,794	1,029,157	25,363
UE 100	3,674,898	3,707,946	33,048

Q. Please explain how well this scenario answers the question posed as criterion one.

A. Again, criterion one asks the question:

> Does this decision encourage electric utilities to analyze and make resource decisions that will yield, "for society over the long run, the best combination of expected costs and variance of cost" to "assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest?"

This scenario makes it harder to answer the question positively because, regardless of some of the positive regulatory policies assumed in this scenario, the result in 1995 would have been a $71 million write-off for PGE. The opportunity to earn a return on equity adjusted for the increased risk investors faced and the share-the-savings payment would have increased the return investors had an opportunity to earn, but such results would have come

only over time and subject to the outcome of other risks PGE faced then. The proper classification of Trojan assets in utility service to protect public safety or accomplish decommissioning also helps encourage least-cost planning decisions by subjecting to the incremental cost analysis only those costs truly avoidable. Protecting safety or meeting governmental requirements for decommissioning are not avoidable.

Q. Please explain how well this scenario answers the question posed as criterion two.

A. Again, this criterion asks:

> Does this decision equitably allocate the costs and benefits of utility resource decisions to customers over time, such that no one "generation" of customers bears an inequitable burden of the costs or receives an inequitable share of the benefits of a given resource decision?

The continued use of a 17-year amortization schedule does help match the costs of closure well with the benefits customers would receive over the period of the net benefits analysis.

Q. Please explain how well this scenario answers the question posed as criterion three.

A. This criterion asks:

> Does this decision preserve the utility's financial integrity and ability to attract debt and equity capital so that the adequacy and cost of service to future customers is not compromised?

This scenario answers this question fairly well. The initial write-off would have weakened PGE's financial condition. Barring significantly unfavorable outcomes to the risks the Commission's ratemaking policies allocated to PGE (load, water, fuel), however, the opportunity to earn a higher return through the risk-adjusted required return on equity and

the temporary share-the-savings mechanism would have improved PGE's financial condition.

Q. Could the Commission, in deciding UE 88, have put the building blocks you discuss together in ways other than PGE's position and the 17-year scenario you discuss above?

A. Yes. For example, the Utility Reform Project (URP) has suggested that all revenue requirement associated with Trojan recovery of and return on should be applied against the un-depreciated balance of Trojan over the UE 88, UE 93 and UE 100 rate periods. One could construe this scenario as one in which the Commission sets an amortization period for the un-depreciated Trojan investment, such that the revenue requirement associated with return on that spread investment, is actually return of investment. This is not precise because using the "return on" revenue requirement in this way does not match any definite multiple-year amortization period.

Q. How would such a scenario measure against the criteria you presented?

A. It would measure up poorly. This scenario would have resulted in an immediate 1995 write-off of $149 million, harming PGE's financial health. Certainly, PGE and all other utilities would have felt no encouragement to engage in least cost planning analysis for existing plants, let alone implement a least-cost decision to retire one before the end of the depreciation life set by the Commission. The lack of recognition of increased risk associated with ORS 757.355 would discourage new investment, debt or equity. Although superficially this scenario would perform adequately at matching costs and benefits over time, in reality, significant costs would have been shifted to future customers, along with some risk that service would not be adequate.

Q. Would these ill-effects in fact have happened in 1995 and subsequent years?

A. No. We are now in 2005. The effects of any decision regarding what the Commission would have done in 1995 through 2000 will have no effect in those years. The effects will happen in 2005 and beyond. We will address this in more detail in Phase II of this docket, if necessary, but it is worth noting that the future effects of adopting scenarios that fail the criteria we present will affect future customers.

VI. Summary of Testimony

Q. Please identify the exhibits PGE is presenting.

A. PGE is presenting the following exhibits:

PGE Exhibit 6100 Ratemaking, Trojan History. Witness Randy Dahlgren reviews the basic methods and principles of ratemaking and describes the sequence of events in Oregon from Oregon's adoption of least cost planning through to the UM 989 settlement.

PGE Exhibit 6200, Quantitative Analysis (PGE Panel). Witnesses Patrick Hager, Jay Tinker, and Stephen Schue quantify the UE 88, UE 93, UE 100 and UM 989 balance sheet effects of the building blocks and assemble those into the one-year and 17-year scenarios I described in Section V.

PGE Exhibit 6300, Asset Classification. Witnesses Stephen Quennoz, Pete Peterson, and Randy Dahlgren explain why the work done to determine appropriate FERC accounting for Trojan assets upon its closure in 1993 should guide the Commission's classification of such assets for purposes of this UE 88 remand and why the earlier classification remains conservative based on knowledge subsequently gained.

PGE Exhibit 6400, Cost of Capital. Witness Patrick Hager explains why the Commission should have found that PGE's required return on equity in UE 88 was in the upper end of the range presented in that docket. He also details effects on PGE's ratios used by credit rating agencies to assess the security of amounts loaned PGE for un-depreciated Trojan investment amortization periods of one and seventeen years. Based on this analysis, he calculates a hypothetical capital structure that could help mitigate some of the negative effects of the amortization decision on PGE's ratios.

PGE Exhibit 6500, The Regulatory Compact. Witness Dr. Jeff Makholm, of the National Economic Research Associates, presents the principles of the regulatory compact as it has developed in the U.S., presents examples in other state jurisdictions of how Commissions have upheld the regulatory compact when dealing with retirement of nuclear plant which had a remaining depreciable basis, and explains how the Court of Appeals interpretation of ORS 757.355 jeopardizes the compact for both investors and customers in Oregon.

PGE Exhibit 6600, Impact on Rate of Return. Witness Dr. Colin Blaydon applies Discounted Cash Flow theory to concur that the required return on equity recommended by Patrick Hager is reasonable.

PGE Exhibit 6700, Risk Premium. Witness Dr. Alan Hess shows that equity investors require a risk premium on their required return under circumstances of asset impairment.

V. Qualifications

Q. Please state 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.

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UE-88 REMAND / PGE EXHIBIT / 6100
DAHLGREN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Ratemaking, Trojan History

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Randy Dahlgren

February 15, 2005

I. Introduction

Q. Please state your name and qualifications.

A. My name is Randy Dahlgren. I am Director of Regulatory Policy and Affairs at PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold. First, I describe the ratemaking process. While those involved in this docket are very familiar with this process, it is important that the record contain basic information on traditional ratemaking as well as some of the ratemaking tools that may be of assistance as the Commission develops a policy to deal with the unprecedented circumstances surrounding this case. Second, I discuss the series of events that led to the closure of the Trojan Plant and to the Commission's original decision in UE 88.

II. The Ratemaking Process

Q. How does the Commission generally set rates?

A. A utility's rates are typically set in the context of a Commission proceeding called a "general rate case," which is most often initiated with a filing by the utility (although the Commission can do so on its own motion). In the filing, the utility proposes new rates that produce a level of revenues (called the "revenue requirement") necessary to cover all costs of providing utility service including its cost of capital. The cost of capital includes a return for its owners (return on equity or ROE) that will result in rates that meet the statutory requirements as well as the Constitutional standards of a fair return found in the Hope and Bluefield decisions of the U.S. Supreme Court.

Q. Please describe the typical steps that occur in a general rate case.

A. A general rate case typically includes the following steps:

1. The utility files for a rate change by submitting to the Commission revised tariff sheets that incorporate new charges (rates). The utility's request is accompanied by supporting documents, including written testimony and exhibits that justify and explain the basis for the change.
2. The rate change becomes effective (generally after 30 days) unless the Commission suspends the filing for review and investigation.
3. If the rate change is suspended, an administrative law judge convenes a pre-hearing conference during which groups, including the OPUC Staff, that are interested in actively participating in the case (parties) are identified and a schedule is set.
4. Parties are given a period of time to submit written questions and data requests to the utility regarding the filing. The utility must respond to such questions within a set amount of time (typically ten business days).

5. Sometime during the process, one or more public hearings are held to hear directly from customers.
6. Parties submit written testimony responding to the utility's request.
7. The utility may submit written questions and data requests to the parties regarding their testimony.
8. The utility files written testimony rebutting the testimony of the parties. There may be additional rounds of rebuttal testimony, but the utility has the last opportunity as it has the "burden of proof."
9. All witnesses who submitted written testimony are made available for cross-examination in a series of hearings.
10. Parties submit final written arguments, or briefs, to the Commission, and the Commission may allow time for oral argument where the utility and parties present their arguments directly to the Commission.
11. The Commission issues its decision in the form of an order.
12. The utility files tariffs in compliance with the order.

Q. Please describe the statutory framework that the Commission uses to evaluate rate proposals.

A. The Legislature has given the Commission the mandate to "obtain for them [customers] adequate service at fair and reasonable rates." That delegation is captured in ORS 756.040(1), part of which I will quote here for convenience:

> "[T]he commission shall make use of the jurisdiction and power of the office to protect such customers, and the public generally, from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates. 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. How are a utility's revenue requirements determined?

A. Revenue requirements are typically based on the utility's cost of providing service over a 12-month operating period called a "test period" or "test year". The test period can actually be of a length other than 12-months, as it was in the original UE 88 docket, which used a 24-month period. The costs include operating and maintenance costs, depreciation and amortization, taxes, interest, and return on equity.

Q. Are costs always used to set utility rates?

A. For most utilities, costs serve as the bases for ratemaking. As James Bonbright states in his oft-quoted work Principles of Public Utility Rates:

> Nevertheless, one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike – the standard of cost of service, often qualified by the stipulation that the relevant cost is *necessary* cost or cost reasonably or prudently incurred. (Page 67)

I have included, as Exhibit 6102, the section contained on pages 67-68 of Principles of Public Utility Rates that this quote is from in order to provide a broader context of Dr. Bonbright's comments.

Q. Please discuss the issue of prudence.

A. In a general rate case, all of a utility's costs are subject to review regarding their prudence. I will not attempt to provide a complete legal description of prudence, but in layman's terms, prudence centers around questions such as:

- Were decisions to invest reasonable at the time they were made in light of the information reasonably available at the time?
- Were investments well managed given the conditions under which they were made?
- Are expenditures reasonable and necessary to provide safe and adequate service?

If the Commission finds imprudence, it will generally exclude from revenue requirements that amount of cost that exceeds a prudent level.

Q. Please describe further the use of a test period in determining a utility's revenue requirement.

A. As I stated, a 12-month operating period is typically used to determine the utility's costs to provide service. Depending on the jurisdiction and utility involved, it may be an historic 12-month period, an historic period adjusted for known or expected changes, or a forecast of a future period. The general objective is to establish a period that reflects the costs and customer usages that will occur when the new rates go into effect. PGE has used forecasted future test periods in its general rate cases since the 1970's. For example, PGE originally filed its UE 88 rate case on November 9, 1993 with an expectation that new rate levels would be approved by about January 1, 1995. Thus, the test period began January 1995. In the case, PGE proposed a 24-month test period to correspond with its proposed mechanism to "decouple" revenues and profits. The test period, then, ran from January 1995 through December 1996.

For the test period, we estimated PGE's Operations and Maintenance (O&M) costs, taxes, and the revenue requirements associated with the ownership of assets (depreciation expenses, interest costs, and ROE).

Q. How do you determine the revenue requirements associated with assets?

A. Recovery of investments in assets is based on a depreciation study approved by the Commission. The depreciation study identifies the expected useful life for each asset type, the estimated net salvage value (positive or negative) and the appropriate mechanism for recovering the plant balance over its useful life (e.g., straight-line, double declining balance, etc.). Depreciation studies are updated periodically, typically in conjunction with general rate cases, to reflect current experiences and expectations particularly with respect to the estimated useful life and net salvage value. For example, the depreciation study used in PGE's last general rate case (UE 115), established an expected useful life of electric meters of 10 years rather than 30 years as used in the previous study. This reflected an anticipated replacement of the current meter technology with new, electronic meters capable of remote reading.

Since the Commission approves the recovery of capital assets over a period of time through depreciation rates, the Commission recognizes that PGE must finance the initial acquisition of capital assets. This acquisition is financed with money invested by equity owners or borrowed from lenders. The financing costs for these funds are considered a component of PGE's cost of service just as O&M costs are considered a cost of service.

In a rate proceeding, the Commission establishes an appropriate capital structure that represents the sources of financing. Typically, such structures include both long-term debt and equity. Preferred stock may also be included in the capital structure. The Commission then establishes the appropriate costs associated with those sources of financing. The costs associated with long-term debt tend to be relatively easy to identify, as debt issues have required coupon/interest payments that must be made to the bondholder(s). In addition, the costs of long-term debt may incorporate issuance expenses, gains/losses on previously re-acquired debt issues, and other costs associated with long term debt. Like coupon/interest payments, these costs also are explicit and relatively easy to verify.

The cost of equity financing, by comparison, is more difficult to determine. There is no explicit cost that can be identified. Equity investors will only provide financing if they expect a return that is commensurate with the level of risk associated with investment. This appropriate amount of return will change over time based on economic conditions and risk levels. There are a number of methods used to estimate this cost, including the DCF and CAPM models described in more detail by Mr. Hager in PGE Exhibit 6400, Section II. Needless to say, these methods are complex and I do not discuss them except to point out that the Commission ultimately rules on an appropriate cost of equity financing as part of a ratemaking proceeding.

As an example, the Commission approved the capital structure and associated costs for PGE for the 1996 test year (OPUC Order 95-322, Appendix F, page 35) as shown in Table 1.

Table 1

Source of Financing	Amount ($000)	Share of Capital	Cost	Weighted Cost
LT Debt	$1,044,215	48.86%	7.82%	3.82%
Pref Stock	$ 99,703	4.67%	8.27%	0.39%
Comm Equity	$ 993,333	46.47%	11.60%	5.39%
Totals	$2,137,251	100.00%		9.60%

In UE 88, the Commission determined that PGE's overall cost of capital was 9.60%, reflecting the respective sources of financing and their associated costs. This rate was applied to PGE's rate base (the investment in assets less accumulated depreciation and accumulated deferred taxes) from UE 88 to derive the financing costs to be included in PGE's overall revenue requirement. In UE 88, the 1996 approved rate base totaled about $1.66 billion (including net Trojan investment). Multiplying $1.66 billion times 9.60%

yields approximately $159 million of operating income that was included in PGE's revenue requirement to reflect the financing costs associated with undepreciated capital assets (*i.e.*, rate base).

Q. Debt appears to be a less expensive form of financing than equity. Why doesn't PGE just finance its capital assets with debt?

A. Increasing the debt load of PGE results in higher risk to lenders as our fixed interest/coupon payments increase. Thus, lenders would demand a higher return to lend money to PGE, increasing the cost of debt. Higher debt load also increases the risk to customers. There is less safety margin of equity to withstand financial shocks that otherwise would affect reliable service. By utilizing both debt and equity, PGE seeks to balance these factors and minimize the overall cost of capital.

Q. Has the Commission recognized these financing costs in establishing PGE's revenue requirement for rate setting purposes?

A. Yes. Commission decisions on rates have consistently recognized all of the costs described above as legitimate costs of service, not only for PGE, but for all of the utilities that come under rate regulation of the OPUC.

Q. Have you provided an example of why this is important?

A. Yes, Exhibit 6101 provides an example of a start-up utility and describes the importance of financing and the need for a utility to attract investment on reasonable terms.

Q. You have discussed the development of revenue requirements in a rate case. Are there any other steps involved in developing the rates that customers pay?

A. Yes, there are two additional steps that we refer to as rate spread and rate design.

Q. Please describe the rate spread process.

A. In rate spread, we allocate the total revenue requirements to classes or groups of customers. For example, residential customers are typically considered a customer class as are small commercial customers and large industrial customers. In Oregon, the Commission has determined that this allocation should be performed based on the utility's long-run marginal costs of providing service to each class. In other words, what is the cost of serving an additional kWh or getting service to an additional customer? Thus, while overall revenue requirements are based on our cost of providing service incorporating our existing system, rate spread is tied to the cost of providing additional service. The intent of this is to provide better "price signals" to customers as they consider using our service. We determine marginal costs of service for each customer class and then sum them to arrive at "total marginal costs." Since it would only be by happenstance that our revenue requirements would exactly equal our total marginal costs, we then adjust our marginal costs on an equal percentage basis to achieve this balance. We refer to this as an "equal percent of marginal costs". Once this is completed, we examine the results to ensure that they provide reasonable results.

Q. What was the result of this analysis in UE 88?

A. We found that a strict application of equal percent of marginal costs would yield rate increases for some customer classes (particularly residential) that were substantially above the average increase while others could potentially receive a rate decrease. We therefore recommended, and the Commission adopted, a methodology that moved towards equal percent of marginal costs but did not completely achieve that goal. The methodology, known as a "4-to-1" rate spread basically allocated to those classes that were currently below an equal percent of marginal costs four times the percentage increase allocated to the other classes. While this process is complicated and somewhat confusing to explain, one thing should be clear. There is no direct correlation between the prices paid by a particular customer class and any particular cost element used in determining the appropriate revenue requirements.

Q. Please describe the rate design process.

A. Rate design is the development of unit prices for each rate schedule. There are three basic types of charges for most of our customers: energy charges based on the amount of energy consumed, demand charges based on the maximum usage of a customer over a 30-minute period or on the customer's maximum potential usage, and customer charges based on the customer's connection to our system and on the related customer service functions provided. We use the results of our marginal cost study to guide our decisions as we develop unit prices that, when applied to our customers' expected usage over the test period, yield the revenue requirement allocated to the particular class during the rate spread process. Again, by the time we get through rate design, there is no direct correlation between a particular charge and a particular cost element in revenue requirements.

Q. Are there a set of principles or objectives that you use in developing proposed rates?

A. Yes. We use a generally accepted set of rate objectives developed by Dr. Bonbright (see page 291 of Principles of Public Utility Rates) to guide our decision-making. The following is my paraphrase of those objectives for effective rates (Exhibit 6103 contains Dr. Bonbright's own words):

- Simple, understandable, and acceptable to the public
- Easily interpreted
- Meets revenue requirement
- Provides revenue stability
- Provides rate stability

- Apportions costs fairly among different consumers
- Avoids undue discrimination
- Discourages wasteful use/encourages justified use

To these, I would add one that is implied but not directly stated:

- Known by the customer and the utility at the time service is used/provided

Q. Why is this last objective important?

A. It is important because, although it serves as the basis for much of the process that I have described, it is not often explicitly stated. The rate case process is designed to develop a set of rates based on a set of costs. However, absent a tracking mechanism such as a power cost adjustment (PCA), or a deferral, once rates are established, they remain in effect until changed. We know that actual costs and customer loads will vary from those used to determine rates. We do not, however, go back and change rates that have been charged. Even when there is a tracking mechanism (e.g., power cost adjustment) rate changes are made prospectively – not retroactively. Customers and utilities need to know the rates that are in effect when they make decisions and not one year or two years or more down the road. This is completely analogous to prices we pay for products every day. I can only imagine the reaction if gas credit card statements contained different pricing than that on the pump when the purchases were made based on the oil company's later determination of its actual costs.

Q. But, if a cost changes doesn't that mean that customers are not receiving fair prices?

A. No, as I mentioned, costs change over time. In fact, most probably do. Some are higher and some are lower. If a utility believes that, in total, costs have increased, it can file a new general rate case or possibly a request for a deferral of specific costs. If other parties believe that, in total, costs have gone down, they can file a complaint case and request that the

Commission open an investigation of the utility's rates, or they too can request a deferral. It should be clear, however, that once we step out of the ratemaking setting into the "real world" of actual costs and actual revenues, the tie between costs and tariff rates is broken. Let me give an example. Suppose that in a general rate case, the Commission determines that an appropriate estimate of annual maintenance costs of overhead lines is $25 million, that local property taxes are expected to be $30 million, and that meter reading expenses will be $4 million. And, as I've described, tariff rates are designed based on these costs. During the year after new rates become effective, however, weather conditions are relatively mild – there is not the normal level of wind damage – and maintenance of overhead lines is actually $22.5 million. On the other hand, voters pass some additional property tax levies, and actual property taxes are $32 million. Actual meter reading expenses are $4.5 million. In this case, if we assume that loads and all other costs are exactly as forecast, we can say that customers "paid" the correct amount for the total of overhead maintenance, property taxes, and meter readings, but the amount for each is unclear. Now, if we consider the actual situation where loads and essentially all cost elements are different from those used to set rates, the problem of identifying the tie between tariff rates and particular costs truly becomes indeterminate.

Q. You mentioned the ability to defer specific cost or revenue items. Doesn't this run counter to your argument that there is no tie between actual costs and tariff rates?

A. While the ability to defer costs or revenue items does appear contradictory, there are several additional factors that must be considered. First, the use of deferrals is relatively rare in the context of the number of cost elements involved. Second, the Commission addresses each request separately based on the unique regulatory and economic circumstances of the request. Finally, the Legislature has required that the Commission consider the overall earnings of the utility when addressing payments on collections under a deferral. This specifically addresses the issue that rates need to be appropriate on a total basis rather than just on an individual cost element basis.

Q. Does the Commission have any other tools besides general rate cases to use in its pursuit of safe and reliable service at fair and reasonable rates?

A. Yes, it does. Integrated resource planning (IRP) is an example of a tool used by the Commission to achieve its goals. The supply of electricity is not only usually the largest part of a utility's costs but also is the one most influenced by past and current decisions. While the costs of distribution are significant, the available choices are limited. The opposite is true of supply.

The Commission ordered that:

> "The goal of least-cost planning is most likely to be attained if all of the options available for providing service are considered and if all the costs are considered. Least-cost planning, as envisioned in this order, requires that broad examination of all the choices. Accordingly, the Commission concludes that the traditional responsibility of utilities for prudent management now explicitly includes the least-cost planning process and the timely acquisition of the least-cost resources." Order No. 89-507 at 2-3.

It stated its expectation that "[t]he results of the process is the selection of that mix of options which yields, for society over the long run, the best combination of expected cost and variance of cost." This tool then guides subsequent ratemaking decisions. "Although a decision made in the LCP process does not guarantee favorable ratemaking treatment, the process should provide some guidance to a utility." Id.

As I discussed above, another useful regulatory tool is deferred accounting. It allows the Commission to respond to unique circumstances such as a sudden and large increase or decrease in a particular cost element or to implement policies that mitigate or smooth rate changes by setting aside a cost or revenue change for future collection or refund.

The Commission has, in the past, used a number of tools in order to pursue policies that it determined were in the public interest and helped it meet its legislative mandate. For example, the Commission, in the early 1990s, decided that saving energy was most likely to result in future adequate service at fair and reasonable rates. The Commission believed that several significant ratemaking conventions, however, gave utilities every incentive **not** to help customers save energy. Among these were that the expenditures for energy efficiency, unlike those for a generating plant, could not enter rate base and thus offered no opportunity to increase net income and that customer savings between rate cases would reduce utility earnings. The Commission changed the convention of treating energy efficiency expenditures as a current cost and ordered utilities to accumulate these costs into rate base. It created mechanisms to hold utilities harmless from savings achieved between rate cases (decoupling). And, significantly, it offered utilities an opportunity to share in the "savings" created by acquiring saved kWh for less than it would cost to generate them (PGE's "SAVE" mechanism). These ratemaking tools, then, enabled the Commission to pursue its goals.

Q. Please provide a brief discussion of the regulatory initiatives undertaken by the Commission prior to PGE's filing of UE 88.

A. Starting in 1989, the Commission began a number of initiatives designed to affect electric utilities' planning and need for new generating resources. First, as I mentioned earlier, in 1989 the Commission issued its least cost planning order (No. 89-507) whose goal was "the selection of that mix of options which yields, for society over the long run, the best combination of expected cost and variance of cost." In that year, the Commission also issued Order No. 89-1700 that authorized capitalization (or rate basing) of the costs of a utility's energy efficiency programs. This was designed to put demand side resources such as energy efficiency on a more equal footing with supply side resources (new generating plants).

The Commission also issued an order (No. 91-1383) that encouraged utilities to use competitive bidding for new resources, and in 1991 approved PGE's proposal for an incentive mechanism that allowed it a share of the savings associated with cost-effective demand-side resources that were installed under its energy efficiency programs (Order No. 91-98). The Commission, obviously, was highly involved and active in the resource planning and acquisition activities of utilities during this time frame.

These conventions or ratemaking tools were available to the Commission when it decided UE 88. With the different understanding of the law that we now have, the Commission may have used some of these tools, or revised its conventions in deciding UE 88.

III. History and Context

Q. Please briefly describe PGE's Trojan facility.

A. Trojan was a single-unit 1,200 MW pressurized water reactor nuclear generating facility. It began commercial operation in 1976, and was licensed to operate through 2011. PGE owned 67.5 percent of the plant. Trojan's use of steam generators in the pressurized water reactor system is important to this proceeding because it was the steam generators that played a major role in the circumstances that led to its early retirement. The Trojan plant contained four steam generators.

Q. Please briefly describe the tube degradation problem at Trojan.

A. The steam generator tubes contain most of the primary system radioactive water, and prevent the release of radioactive water to the secondary system. Each of Trojan's four steam generators contained several thousand tubes, which began to seriously degrade beginning in 1989. PGE used two techniques, plugging and sleeving, to address Trojan's tube degradation problem. Plugging removes a tube from operation by stopping the flow of primary system water through it, and sleeving involves permanently attaching a second tube within an existing degraded tube. By 1991 PGE had plugged or sleeved more than 25 percent of all Trojan steam generator tubes, which led to increased operation costs and decreased capacity of the plant.

Q. Given the increased O&M expenses and decreased capacity, what did PGE decide to do?

A. PGE considered three possible courses of action in its 1992 Integrated Resource Plan. These were 1) an immediate Trojan shut-down, 2) a phase-out, such that Trojan would close in mid-1996, and 3) continued operation of Trojan through 2011. The third option required the replacement of Trojan's steam generators.

Q. What were the conclusions of the 1992 IRP?

A. This Plan concluded that a Trojan phase-out was the least-cost option for customers over the 1992-2011 period.

Q. What new event occurred on November 9, 1992?

A. On November 9, 1992, a steam generator tube leak forced PGE to shut down the Trojan plant. This was shortly after submission of the 1992 IRP, but after the phase-out decision had been made.

Q. How did the Nuclear Regulatory Commission and the Union of Concerned Scientists respond to this event?

A. On December 1, 1992, the Nuclear Regulatory Commission (NRC) held a public meeting at Trojan to hear PGE's report on repair of the leak and determination that no similar welding flaws existed. This meeting also included some discussion of documents that the Union of Concerned Scientists (UCS) had recently released. The UCS documents indicated that there were differing professional opinions within the NRC regarding the safety analyses previously done for plants with steam generator micro-flaws, such as Trojan. Disagreements concerned both the ability to detect steam generator micro-flaws and the possibility that multiple tube leaks could lead to a serious accident. The UCS requested formal hearings on these matters prior to a Trojan restart.

Q. What did PGE then decide to do?

A. On December 4, 1992, PGE decided to delay restart to collect and evaluate data on the condition of the steam generator tubes. During this process, PGE learned that emergent cracks had developed since the 1991 inspections. The potential cost and complexity of testing and repair were very high.

Q. How did the Oregon Department of Energy respond to these Trojan-related events?

A. On December 9, 1992, the Oregon Department of Energy announced its decision to conduct public hearings on the safety of Trojan's steam generators in January 1993.

Q. Given these developments, did PGE decide to update its analysis?

A. Yes. Given these developments, PGE decided to update its 1992 IRP with a cost-benefit analysis of the decision whether to repair the steam generators and continue to rely on Trojan through mid-1996, or to close the plant immediately. Key parameters were Trojan's capacity factor, sleeving and outage costs, and short-term replacement power costs.

Q. What were the conclusions of this analysis?

A. This analysis showed immediate plant closure to be less expensive to customers, except under the combined assumptions of a very low mid-cycle outage probability and very high replacement power costs. Under mid-point replacement power cost assumptions, the net present value savings to customers of an immediate closure were between $78 million and $127 million, depending on the mid-cycle outage probability. PGE announced its decision to permanently close Trojan on January 4, 1993, and filed an Update to its 1992 IRP on February 2, 1993. The Update contained PGE's net benefit analysis supporting this decision.

Q. Did the Commission acknowledge PGE's IRP and Update?

A. Yes. The Commission acknowledged PGE's 1992 IRP and Update in Order No. 93-803 (LC-7).

Q. Did the Commission earlier request a legal opinion from the Oregon Department of Justice?

A. Yes, on March 19, 1992, the Commission requested an opinion from the Oregon Department of Justice concerning Trojan cost recovery if the plant were shut down with a substantial balance still to be recovered. The Department of Justice issued its response, Opinion Letter OP-6454, on June 8, 1992. Among other questions, the Commission asked whether it may allow rate recovery of the total plant costs, including decommissioning costs; recovery of the capital invested in the plant, and return on the unamortized or undepreciated investment during the recovery period. The Department of Justice answered in the affirmative, stating that the Commission has authority to allow recovery of capital and non-capital costs under both ORS 757.140 and the general ratemaking principle of "net benefits." The opinion letter also concluded that ORS 757.355 does not apply to a plant that has been in service.

Q. Please describe PGE's request for a declaratory ruling.

A. On February 9, 1993, PGE filed a request for a declaratory ruling, asking the Commission to state that it would apply its legal authority under ORS 757.140 and the "net benefit principle," and allow PGE to recover the capital and non-capital costs associated with the Trojan Plant through 2011, provided that PGE show, in a contested proceeding, that Trojan's retirement occurred "to assure an adequate and reliable supply of electricity at the least cost to the utility and its customers consistent with the long-run public interest." PGE based its understanding of the Commission's powers on Opinion Letter OP-6454. In Dockets DR-10 and UM 535 the Commission considered PGE's request, and responded in Order 93-1117, which it issued on August 9, 1993.

Q. Please describe the Commission's conclusions in Order 93-1117.

A. In Order No. 93-1117 the Commission concluded that a utility could demonstrate that a plant closure is in the public interest by means of showing a "net benefit" from that action. It also set out the conditions under which it would favor allowing PGE to recover some or all of its undepreciated Trojan investment and a return on that investment. First, PGE had to demonstrate that six assumed facts in the declaratory ruling request were actually true.

In addition to proving these six assumed facts, the Commission listed five additional conditions that PGE had to meet for the Commission to favorably consider allowing PGE to recover in rates some or all of the return of and return on its undepreciated investment in Trojan.

Q. Did PGE rely on the outcome of DR 10 in its subsequent general rate case, docketed as UE 88?

A. Yes, we did. We assumed that, if we met our burden of proof with respect to the required elements, the Commission would approve a revenue requirement for PGE that included our interest cost associated with Trojan and a profit opportunity on the remaining balance.

Q. How did PGE request Trojan cost recovery?

A. In Docket UE 88, PGE requested Trojan cost recovery based on a two-year 1995-96 test period. Specifically, PGE requested full recovery of the Trojan undepreciated balance based on a 17-year amortization of the Trojan balance ending in 2011 consistent with the then remaining depreciation period, the cost of debt – interest – associated with the remaining Trojan balance and an opportunity to earn a return on common equity on the outstanding Trojan balance over the test period.

Q. Please give an overview of how the Commission viewed PGE's request.

A. In considering PGE's request, the Commission relied on the framework of Order No. 93-1117. PGE and OPUC Staff agreed that PGE had proved all of the assumed facts, except for the third. Staff contended that PGE's $14.9 million in post-1991 capital costs incurred for analysis and plugging and sleeving of steam generator tubes should be disallowed, because these expenditures had never been in PGE's ratebase. Staff also recommended disallowance of the $2.2 million that PGE had spent for a spare coolant pump motor. PGE ordered the spare motor in 1991, but it had not yet been delivered when PGE closed the plant in early 1993. Staff argued that the purchase was not supported by adequate analysis. The Commission agreed with Staff on these two issues, leading to a disallowance of $17.1 million.

With respect to the second condition in DR 10 – diligent efforts to reduce other costs – the PGE and Staff cases disagreed. The Commission agreed with Staff that it was possible for PGE to be still more aggressive in its efforts to reduce costs. Accordingly, the Commission reduced PGE's revenue requirement by one percent, or $1.631 million and $1.687 million in 1995 and 1996 respectively.

The Commission considered PGE's 1992 IRP and Update sufficient to prove the sixth assumed fact under the Order No. 93-1117 framework. The 1992 IRP showed that a Trojan phase-out was the least-cost option. Then the Update showed that immediate shut-down was cheaper than phase-out.

The primary controversy in UE 88 arose in connection with the third condition of DR 10: PGE must show why it is reasonable to allow 100 percent recovery of Trojan-related costs in rates. The Commission determined to apply a net benefit test, based on the IRP result but updated for more current information, to answer this question and ensure "the ratepayers were held harmless for imprudent operation or management of Trojan, and to share costs between ratepayers and shareholders on that basis." Order No. 95-322 at 2. Numerous issues arose between the parties regarding the creation of the inputs to the net benefits test. Staff, in particular, recommended a number of changes to PGE's net benefit study.

Q. What were the results of the net benefits analysis, once it incorporated Staff's adjustments?

A. PGE's 1992 IRP net benefit analysis showed phase-out to be much cheaper for customers than continued operation through 2011. The analysis in PGE's Update then showed immediate shut-down to be much cheaper than phase-out. However, Staff's analysis in UE 88, which assumed lower O&M costs, a higher capacity factor, and a $183.1 million disallowance related to steam generator replacement, showed that shut-down had a net present value cost to customers that was $23.6 million greater than that of continued operation through 2011. This included a 45 MW increase in Trojan's capacity in 1996, concurrent with steam generator replacement, in the "continue operation through 2011" alternative. In other words, this analysis disallowed the cost of new steam generators required for continued operation through 2011 but included the increase in capacity that they enabled.

Q. How did the Commission rule on the net benefits analysis?

A. The Commission adopted Staff's $23.6 figure as the base cost to customers of PGE's decision to close Trojan. It then approved six of seven adjustments it considered. These were related to 1) timing of the 45 MW capacity upgrade, 2) capacity factor adjustment, 3) fixed O&M definition, 4) mismatch in nuclear fuel costs between Case 1b in PGE's 1992 IRP and Scenario 3 in the Update, 5) carrying charges related to capital replacements for alternative resources, and 6) capital costs for new gas-fired plants. There was also a final adjustment to account for interactions. The net result of these adjustments was to decrease the Staff's $23.6 million net benefit result by $3.2 million, or to $20.4 million.

Q. Please summarize the Commission's ruling on the net benefits test and other Trojan-related costs in docket UE 88.

A. The Commission accepted the adjusted Staff net benefit test result, which concluded that PGE's decision to close Trojan had a net present value customer cost that was $20.4 million higher than that associated with the alternative of continuing to run Trojan through 2011. The Commission then added this amount to the disallowances of $14.9 million and $2.2

million for post-1991 plugging and sleeving and the purchase of a spare reactor coolant pump motor respectively. This resulted in total Trojan-related disallowances of $37.5 million in the UE 88 docket. The Commission's order in this docket (No. 95-322) was issued on March 29, 1995, and implementing rates became effective for service on April 1, 1995.

Q. Please briefly summarize the major dockets that occurred subsequently: UE 93, UE 100 and UM 989.

A. In UE 93 PGE requested and the Commission approved increased rate levels that brought the recently completed Coyote Springs generating plant into rate base and increased variable power costs resulting from BPA's October 1995 rate increase. The order in this docket (No. 95-1216) also authorized the use of the gain resulting from PGE's sale of a portion of the Boardman Coal Plant to offset certain deferred amounts including: power costs and interest in UM 529, UM 594 and UM 692, the AMAX coal contract termination payment, and the incentive earned by PGE under the SAVE program (Schedule 101). Any remaining gain was applied to the Trojan balance. In total, about $117.2 million of Boardman gain was applied in this manner. The reduction in the Trojan balance was $20 million. The revised rates resulting from UE 93 became effective November 28, 1995.

Docket UE 100 was the culmination of a series of discussions held during 1996 between PGE, OPUC Staff, and other stakeholders regarding apparent significant power and fuel cost reductions that had occurred. These discussions resulted in a stipulation between PGE, OPUC Staff, the Citizens' Utility Board (CUB), and the Oregon Committee for Equitable Utility Rates (representing some of PGE's industrial customers) that provided for rate reductions for our customers. The OPUC opened UE 100 to consider the stipulation and adopted it by Order No. 96-306. The rate reduction went into effect on December 1, 1996.

Finally, in UM 989 the Commission adopted, by Order No. 00-601 dated September 29, 2000, a stipulation between PGE and OPUC Staff and one between PGE and CUB that were meant to resolve disputes concerning UE 88 rates by eliminating the remaining Trojan investment balances and offsetting them with various liabilities coupled with an approximate $6 million after-tax write-off by PGE. Also included was a rate reduction of $10.2 million (on an annual basis). The order was later affirmed by the Commission in Order No. 02-227.

IV. Qualifications

Q. Please state your qualifications.

A. I received a BS degree from Oregon State University in Electrical Engineering. In addition, I have taken courses from other universities in the areas of engineering economics, systems analysis, and business administration. I also attended the 1980 Public Utilities Executives' Course at the University of Idaho.

I joined PGE in 1973 shortly after graduation and subsequently have been involved in the areas of load research, load and revenue forecasting, price analyses and design, and class cost-of-service analyses. I was appointed Rate Engineer in January 1977 and have held various management positions in the regulatory area since 1978. I entered my present position as Director of Regulatory Policy and Affairs in 2001.

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List of Exhibits

PGE Exhibit	Description
6101	Example Start-Up Utility
6102	The Widespread Acceptance of a Cost-Price Standard
6103	Criteria of a Sound Rate Structure

Example Start-Up Utility

Imagine a new start-up utility (Metropolis Electric Co – MEC). Before MEC can serve any customers, it must build or purchase the infrastructure necessary to provide service. The infrastructure includes power plants to generate power, transmission lines to bring the power to its service territory, distribution infrastructure including poles and wires to bring the power to end use customers, transformers, electric meters, service trucks, billing and customer service systems, computers and desks, materials and supplies. MEC has 10,000 residential customers that it would like to serve. If it costs $5,000 per customer to build or purchase the infrastructure needed to begin service, MEC is going to need to raise $50,000,000 in capital.

Who will provide MEC with the necessary money? MEC could go to the debt markets. Lenders will require that MEC have an adequate financing profile and will be expected to make interest and principal payments against the loan (as well as a reserve margin – a "coverage ratio") before they lend any money to MEC, or to determine the interest rate on the debt.

MEC could also seek to find equity investors who will provide funding in exchange for a claim on the profits associated with the business as well as a residual claim on the assets of MEC after debt holders.

Any lenders or equity investors will take risks in providing MEC with money. First, the business may not generate the cash flow necessary to support interest/principal payments to the bondholders. This could occur if management wastes money on non-essential items, for example. Second, equity investors are not guaranteed any return on their investment. If MEC is faced with operating losses year after year, eventually MEC will go out of business, potentially without ever making a payment to its equity investors. As a result, any potential investor must weigh the alternatives of investing in other businesses. Generally speaking, investors would not invest in MEC unless they expected a return that is commensurate with potential returns of other investments of comparable risk.

After consideration of potential alternatives, MEC issues $25,000,000 in bonds that carry an 8% coupon rate and have a term of 30 years. These bonds are purchased by investors who supply MEC with the $25,000,000. The term of 30 years was selected since it matches the expected life of the assets that must be built/purchased. Potential equity investors review MEC's financial plan and forecasts for the coming years. After consideration of alternative investments of comparable risk that could provide an 11% return, they provide an infusion of equity of $25,000,000. Note that the $25,000,000 provided by the equity investors is not subject to any particular schedule of repayment. They are counting on the ability of MEC to generate income to justify their investment.

After obtaining the necessary funding, MEC builds/purchases the necessary infrastructure to begin serving customers. Simultaneously, MEC files its first rate case with the OPUC so that it can lawfully charge rates to its customers.

Both the equity investors and the holders of MEC's bonds are hopeful that the OPUC will allow a revenue requirement that reflects the costs of financing, as well as fuel, operating, and maintenance costs. Further, their investment is influenced by the ability of MEC's management team to manage the costs of the business. If, for example, the OPUC approved MEC's revenue requirement, but the cost of power increased, MEC's income would fall short of the $2.75 million ($25 million at 11%) that the equity investors had expected. But this start-up example does not end the story. MEC will require an annual infusion of new investment to support load growth and the replacement of worn out facilities. This will need to come from new debt or equity financing and/or from the retention and reinvestment of retained earnings in the business.

The point of this example is to illustrate the importance of attracting capital on an ongoing basis for a capital intensive business like an electric utility.

THE WIDESPREAD ACCEPTANCE OF A COST-PRICE STANDARD

No writer whose views on public utility rates command respect purports to find a single yardstick by sole reference to which rates that are reasonable or socially desirable can be distinguished from rates that are unreasonable or adverse to the public interest. A complex of tests of acceptability is required, just as would be the case with the tests of a good automobile, a good income-tax law, or a good poem. Nevertheless, one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike—standard of cost of service, often qualified by the stipulation that the relevant cost is *necessary* cost of cost reasonably or prudently incurred. True, other factors of rate making are potent and are sometimes controlling--especially the so-called value-of-service factor in the determination of the individual rate schedules. But the cost standard has the widest range of application. Rates found to be far in excess of cost are at least highly vulnerable to a charge of "unreasonableness." Rates found well below cost are likely to be tolerated, if at all, only as a necessary and temporary evil.

A cost standard of rate making has been most generally accepted in the regulation of the levels of rates charged by private utility companies. But even more significant is the widespread adherence to cost, or to some approximation of cost, as a basis of rate making under public ownership. Thus the great Hydro-Electric Power Commission of Ontario purports to apply the principle of "service at cost" in its charges for wholesale power supplied to the various municipal distribution systems of the province. And thus most of the Federal power projects in the United States, including the Tennessee Valley authority, purport to sell electric power at rates designed to cover operating expenses plus a compensatory return on allocable capital investment—one form of cost-of-service standard. To be sure, critics of these projects have insisted that, under proper accounting, revenues would be shown to fall short of full-cost coverage. But the mere fact that these allegations are generally denied by the responsible managements of the Federal agencies implies that these managements themselves concede the validity of a cost principle of rate making.

Lest the foregoing remarks be taken to imply an adherence to a cost standard more rigid than the facts would justify, let me at once note exceptions. In the first place, the principle is followed far more closely as a measure of general rate levels than as a measure of individual rate schedules. In the second place, it is deliberately violated by those municipal power plants, said to be fairly numerous, that use the sale of electricity as a source of larger profits for the city treasury. And in the third place, it has been waived to a minor degree through the use of indirect subsidies in support of rural electrification in the United States; and waived to a major degree through the use of heavy subsidies for rural electrification in the province of Ontario. One may also note the huge deficits incurred in the operation of the Canadian National Railways, and the failure of most metropolitan transit systems, in recent years, to charge fares that cover operating expenses plus fixed charges.

Important, however, as are these and other deviations from a cost-price standard, they are generally treated as exceptions to the general rule of rate making. In Great Britain, even Labor Government that went much farther than did this country in the direction of socialization, including socialized medicine, did not see fit to abandon the general criterion of service at cost when it nationalized its public utilities. Instead, it instructed the various boards, such as the

British Electricity Authority, to undertake to realize total revenues sufficient to meet total outlays properly chargeable to revenue account, "taking one year with another."[1]

[1] The British statutes governing the rates to be charged by the nationalized public utilities and railroads do not expressly forbid sale of services at prices designed to yield revenues in excess of total cost. But they have been interpreted by British commentators as contemplating the provision of service "without making, so far as possible, either a deficit or a surplus." William A. Robson, ed., *Problems of Nationalized Industry* (New York, 1952). P. 335.

James C. Bonbright, *Principles of Public Utility Rates* (Columbia University Press 1961).
pgs. 67-68

CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    (a) in the control of the total amongst of service supplied by the company:
    (b) in the control of the relative uses of alternative types of service (on-peak versus of-peak electricity. Pullman travel versus coach travel, single-party telephone service versus service from a mulit-party line, etc.).

James C. Bonbright, *Principles of Public Utility Rates* (New York Columbia University Press 1961). pg. 291

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Quantitative Analysis

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jay Tinker
Stephen Schue
Patrick G. Hager

February 15, 2005

I. Introduction

Q. Please state your names and positions

A. My name is Jay Tinker. My position is Project Manager in the Rates and Regulatory Affairs Department. My qualifications are in Section X at the end of this testimony.

My name is Stephen Schue. My position is Senior Analyst in the Rates and Regulatory Affairs Department of PGE. My qualifications are in Section X at the end of this testimony.

My name is Patrick G. Hager. My position is Manager, Regulatory Affairs. My qualifications are in Section IV of PGE Exhibit 6400.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to identify and describe the financial impacts of the ratemaking tools (the "Building Blocks") available to the Commission in responding to the issue in this docket: what would the Commission have done in UE 88 if it had known of the Oregon Court of Appeals' interpretation. Ms. Lesh sets forth the Commission's use of, and regulatory foundation for, these Building Blocks. We focus on the financial impact of each Building Block and then analyze the financial impact of three approaches that combine various Building Blocks.

Q. What is the framework for your financial analysis?

A. We focus on four financial impacts. We review the Building Blocks' impact on PGE's revenue requirement over three rate periods; UE 88, UE 93, and UE 100 spanning the period April 1, 1995 (the effective date of UE 88) through September 30, 2000 (effective date of UM 989). We state how the revenue requirements during the various rate periods would differ using the Building Blocks as compared with the approved revenue requirements the Commission established in UE 88, UE 93, and UE 100. Throughout our testimony, we state the revenue requirement difference in *nominal* dollars, not net present value. In addition, we review the financial impact of the Building Blocks on PGE's balance sheet as of September 30, 2000.

Q. Why do you focus on these financial impacts?

A. This is a remand proceeding for the final orders in UE 88 and UM 989. The UE 88 revenue requirement, using the combination of Building Blocks we recommend, is important in determining whether a refund is due customers because of the UE 88 remand. If the revenue requirement under the Building Blocks the Commission would have selected in UE 88 is higher than the approved UE 88 revenue requirement, customers are due no refund. Similarly, PGE's balance sheet as of September 30, 2000, using the Building Blocks, is crucial to understanding whether the UM 989 settlement is reasonable.

Q. How do you state assets or liabilities in your testimony?

A. Unless otherwise noted, we use the *pre-tax balances*. That is, we do not include the effect of taxes unless we specifically note otherwise.

Q. Please explain how you use PGE's balance sheet as of September 30, 2000, to assess the UM 989 settlement and final order.

A. The UM 989 settlement and final order eliminated the remaining Trojan balance of $180 million in exchange for about $161 million in customer credits. The Commission found that the UM 989 settlement benefited customers because, among other things, it eliminated a customer debt of $180 million in exchange for only $161 million in customer credits. Under the alternative approaches we discuss that the Commission could have taken in UE 88, we review PGE's balance sheet to see whether customers still would owe PGE $180 million or more as of September 30, 2000. If so, the UM 989 settlement and final order continue to benefit customers because the settlement eliminates customer debts of over $180 million in exchange for customer credits of $161 million. In fact, remaining balances of less than $180 million, as long as above $161 million, would imply that customers still benefited from the UM 989 settlement.

Q. What assets do you review on PGE's balance sheet as of September 30, 2000?

A. We focus on customer liabilities to PGE that are available at the time. The nature of customer liabilities varies depending upon the combination of Building Blocks used. They include the Trojan unamortized balance, certain regulatory assets (AMAX, SAVE, and the Trojan replacement power deferrals), sharing of savings, the potential 1995 power cost deferral (see PGE Exhibit 6000, Section IV. F), and the difference in UE 88, UE 93, and UE 100 rate period revenue requirements using the Building Blocks.

Q. What do you mean by the difference in revenue requirements using the Building Blocks?

A. The revenue requirements in UE 88, UE 93, and UE 100 using the Building Blocks differ from the revenue requirements set in those cases. We take the net present value of that difference in revenue requirements and state it as a customer debt if the revenue requirement is higher using the Building Blocks or as a customer credit if the revenue requirement is less using the Building Blocks. This makes sense because we are trying to assess how PGE customers would have fared under the alternatives as compared with what actually occurred. We state this difference in revenue requirements in net present value terms as of September 30, 2000.

Q. What conclusions do you draw from the combination of Building Blocks Ms. Lesh recommends?

A. We conclude that no refund is due customers for the UE 88 rate period and that the UM 989 settlement still provides substantial benefit to customers and should be reaffirmed. Under both the alternatives Ms. Lesh recommends[1], the UE 88 revenue requirement would have been higher than the approved UE 88 revenue requirement and customers would have owed PGE more than $180 million as of September 30, 2000.

Q. Please outline your testimony.

A. We address the following topics:

- In Section II, we provide the ratemaking and financial impacts of different recovery periods for the Trojan investment, using a recovery period through 2011 (the "17-year recovery period"), and a one-year recovery period, as bookends.
- In Section III, we discuss re-evaluation of the cost of common equity and capital structure found in UE 88 based on ORS 757.355 as interpreted by the Court of Appeals, which concluded that rates may not include a return on economically retired plant.
- In Section IV, we restate the UE 88 net benefit test, given that the closure of Trojan scenario analyzed in that test should not include a return on the Trojan investment. We also set forth the impact on the UE 88 net benefits test if the Commission changed its decision in UE 88 and included recovery of steam generator replacement in the costs of continued Trojan operation.
- In Section V, we address the Building Blocks available based upon the restated UE 88 net benefits test, including the application of the Commission share-the-savings policy,

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[1] See PGE Exhibit 6000. Ms. Lesh suggests two alternatives. However, a one-year amortization period along with other changes is considered preferable from a policy perspective than the second alternative, which uses a seventeen year amortization period.

developed to encourage utility energy efficiency investment, to the economic retirement of generating plant, thus yielding positive net benefits.

- In Section VI, we discuss the classification of the remaining Trojan plant to recognize as plant-in-service those portions of the plant still necessary for the protection of public safety.
- In Section VII, we describe the option of offsetting the unamortized Trojan balance with customer credits existing at the time of the UE 88 final order.
- In Section VIII, we discuss creating a new deferred account of certain 1995 net variable power costs for purposes of achieving intergenerational equity if the Commission selected a one-year recovery period for Trojan.
- In Section IX, we analyze the financial implications of three different alternative approaches, which combine in different ways the Building Blocks discussed above.

II. Amortization Period

Q. What recovery periods do you describe in this section?

A. A 17-year recovery period and a one-year recovery period. While there are other possible recovery periods, these two alternatives are instructive because they act as bookends.

A. 17-Year Recovery Period

Q. Please describe the impact of a 17-year recovery period with no return on equity and no recovery of PGE's debt costs on PGE's revenue requirement for UE 88, UE 93, and UE 100.

A. Under this scenario, the revenue requirement for each rate period would have been lower. Over the period from April 1, 1995 (the effective date of UE 88 rates) through September 30, 2000 (the effective date of the UM 989 settlement), the revenue requirement would have been lower in all periods. The total revenue requirement during this period, with these assumptions, would have been reduced by $186.5 million.

Q. Would this have had an immediate impact on PGE's balance sheet and earnings?

A. Yes. Financial Accounting Standard (FAS) 90 would require an adjustment to PGE's balance sheet to reflect recovery of the Trojan balance over time without any interest or equity return.

Q. Can you explain FAS 90 in more detail?

A. Financial Accounting Standard (FAS) 90 relates to accounting for abandoned plant costs and disallowances of plant costs. For plant balances that fall under FAS 90, an asset impairment test is required if it is likely that a regulatory commission will provide only a partial return on or no return on the remaining unamortized balance.

Q. Why is FAS 90 relevant to Trojan and these remand proceedings?

A. To the extent that the Commission considers alternatives to the UE 88 decision that allow no return on the Trojan balance, FAS 90 would require the application of an asset impairment test. The results of any impairment test should be included in the analysis of the effects of such an alternative Commission decision.

Q. Does the full unamortized balance of Trojan fall under FAS 90?

A. Not quite. Approximately $322 million of the $340 million unamortized balance for Trojan at April 1, 1995 was considered FAS 90 assets by PGE's auditors. The remaining $18 million of costs were considered assets under FAS 71 (regulatory assets). Prior to the write-off ordered in UE 88 pursuant to the net benefits test, the FAS 90 balance was approximately $345 million of a total unamortized balance of $367 million.

Q. What is a FAS 71 asset?

A. FAS 71 assets are assets created at the discretion of the Commission. Typically, these are the results of deferred O&M costs.

Q. Are FAS 71 and FAS 90 assets treated differently?

A. Yes. FAS 71 assets are not subject to impairment as long as full recovery of the asset is allowed by the Commission. FAS 90 assets, however, are subject to impairment if less than full return on the assets is authorized by the Commission.

Q. How does the FAS 90 impairment test work?

A. Basically, the FAS 90 impairment test is a comparison of the unamortized balance of the asset to the *present value* of the future cash flows authorized by the Commission to support that asset. Thus, if the Commission were to require no return on the unamortized balance, the size of the impairment would increase with the length of the Commission-required amortization period.

Q. What is the discount rate used in FAS 90 impairment testing?

A. The discount rate is the incremental borrowing rate of the company for debt of the magnitude and term of the Commission-approved unamortized balance and amortization period.

Q. How does the FAS 90 impairment test apply to a 17-year recovery period?

A. With a 17-year recovery period, the write-off pursuant to a FAS 90 impairment test would have been approximately $160 million on the pre-write off balance of $345 million and approximately $149 million on the $322 million of FAS 90 assets after the UE 88 write-off.

Q. For the 17-year recovery period, would FAS 90 require PGE to book the impact of the impairment immediately?

A. Yes. FAS 90 would require that the Trojan asset be written down at April 1, 1995 so that the asset's value was equal to the present value of the future cash flows authorized by the Commission that supported the asset.

Q. What happens in the other areas of the balance sheet?

A. The after-tax impact of the write-off would flow through net income and reduce retained earnings on the balance sheet.

Q. Does this assume PGE receives neither a return on equity nor recovery of its debt costs associated with the Trojan investment?

A. Yes. If the Commission were to allow recovery of PGE's debt cost, the impact of the impairment test would be reduced.

B. One-Year Recovery

Q. Please describe the revenue requirement impact of a one-year recovery period for the Trojan investment?

A. For the first twelve months after the effective date of UE 88 rates, PGE's revenue requirement would have been $262 million higher. Thereafter, the revenue requirement would have been lower by approximately $220 million over the period from April 1996 through September 30, 2000. Accordingly, the overall revenue requirement for the five and one-half year period from April 1995 through September 30, 2000, would have been $42 million higher.

Q. Please describe the impact on PGE's earnings and balance sheet of a one-year recovery period?

A. For the scenario in which Trojan is collected over one year, the FAS 90 impairment test would require a write-off of about $26 million for the pre-UE 88 write-off FAS 90 balance of $345 million and about $24 million for the $322 million post-UE 88 write-off FAS 90 balance.

III. Return on Equity, Debt Costs, and Capital Structure

Q. What is the distinction between return on equity and debt costs?

A. PGE's cost of capital has two components: debt and equity. The cost of debt represents interest payments that PGE must make or risk default. Return on equity is the profit opportunity investors require to make equity capital available. Failure to earn profit does not have the same legal consequences (default risk) as failure to pay debt.

Q. Why is the distinction important here?

A. As discussed in greater detail in the PGE Opening Brief, the Court of Appeals' interpretation held that ORS 757.355 prohibits a utility from earning a "profit" on retired plant. The Court of Appeals' interpretation does not address interest costs of outstanding debt securities.

Q. What is the financial impact of this distinction?

A. The impact varies depending upon the Building Blocks selected. Generally speaking, the distinction would increase the revenue requirement during the recovery period of Trojan. The magnitude depends upon the balance to which it applies and the amortization period. The particular approaches discussed in detail below and in PGE Exhibit 6000 all conservatively assume that the Oregon Court of Appeals' interpretation bars recovery of both interest costs and return on equity associated with the Trojan investment.

Q. What other Building Blocks are available to the Commission?

A. As Mr. Hager testifies (PGE Exhibit 6400, Section III.), the Court of Appeals' interpretation would have increased PGE's required return on equity in UE 88 because equity investors would view an investment in PGE as riskier. PGE's authorized return on equity would therefore need to be higher in order to attract capital and to provide equity holders with a return that is commensurate with the return on investment in other enterprises having corresponding risks.

Q. Under a 17-year recovery period, what would PGE's required return on equity have been?

A. According to Mr. Hager's testimony, PGE's required return on equity would have been 13.1%, or 150 basis points higher than authorized in UE 88.

Q. Would the authorized return on equity be the same for UE 93 and UE 100?

A. Yes. Neither UE 93 nor UE 100 changed the authorized return on equity set in UE 88.

Q. What effect would that cost of common equity have had on the revenue requirement over the five and one-half year period from April 1995 through September 30, 2000?

A. Over this five and one-half year period, the revenue requirement would have been $102 million higher than the approved revenue requirement.

Q. Under a one-year recovery period, what return on equity would have been required?

A. According to Mr. Hager's testimony, PGE's required return on equity would have been 11.85 percent or 25 basis points higher than the UE 88 level. This higher level of equity return applies to the UE 93 and UE 100 revenue requirement given that these rate orders did not alter PGE's authorized return on equity.

Q. What effect would that cost of common equity have had on the revenue requirement during the five and one-half year period from April 1995 through September 30, 2000?

A. PGE's revenue requirement would have been approximately $17 million higher.

Q. Do you believe the Commission would also change PGE's capital structure?

A. Yes. As Dr. Blaydon states (PGE Exhibit 6600, Section III.), a change in PGE's capital structure would have been appropriate if the Commission were to require a 17-year recovery period with no return on the Trojan investment.

Q. How did you calculate the adjustment to PGE's capital structure?

A. First, for illustrative purposes we assumed a shift of 10% from debt to equity in the UE 88 capital structure. Second, we applied the difference between PGE's pre-tax return on equity and cost of debt to PGE's approved rate base with the Trojan investment removed.

Q. What is the annual impact of this change in PGE's capital structure?

A. Based on UE 88, the annual impact would be an increase of $16 million in PGE's revenue requirement.

Q. What would the financial impact be in UE 93 and UE 100?

A. The financial impact would be approximately the same. The only difference would be the result of changes in the approved rate base in UE 93 and UE 100.

Q. Do you include this capital structure adjustment in the scenarios proposed later in your testimony and in Ms. Lesh's testimony?

A. No. Nevertheless, a capital structure adjustment is a well-recognized ratemaking tool that the Commission could use in dealing with the unprecedented circumstances presented in this docket.

IV. Net Benefit Test

Q. How did the Commission determine the amount of recoverable Trojan costs in UE 88?

A. The Commission applied a net benefits test to determine the allowable Trojan cost recovery. The net benefits test built on the work done in the 1992 IRP which found that an early phase-out (in 1996) of Trojan was the least cost option for PGE's customers. In a subsequent update to the 1992 IRP, PGE provided documentation that an immediate shutdown (in 1993) of Trojan was the least cost option for PGE's customers. The OPUC used the 1992 IRP and the subsequent update as the starting point of its analysis of net benefits in UE 88. Specifically, the Commission approved the use of Case 1-b from the 1992 IRP and Scenario 3 from the Update as the beginning point of analysis in UE 88.

Q. Can you describe the conceptual framework of the net benefits test?

A. Yes. The Commission conceptualized the net benefit test as follows (See Order No. 95-322, pg. 33):

(X + Y) > (X + Z), where:

X = Unamortized investment in Trojan

Y = Expected Allowable Long-Term Costs of continued Trojan Operation

Z = Replacement Resource Costs

Thus, a net benefit occurred if the Replacement Resource Costs (Z) were less than the Expected Allowable Long-Term Costs of Continued Trojan Operation (Y). The 1992 IRP Case 1b indicated a net customer benefit of a 1996 phase-out of Trojan of $110 million in then-present value terms. The Update to the 1992 IRP indicated a further net benefit to immediate shut-down in 1993 relative to a 1996 phase-out of $78 million (NPV). Thus, the starting point of the net benefit analysis in UE 88 was a net benefit of immediate Trojan closure of $188 million.

Q. What happened next?

A. During the UE 88 proceeding, the parties to the case debated the assumptions used by PGE to derive the $188 million net benefit of immediate shutdown over continued operation. Effectively, the parties debated the assumed Replacement Resource Costs (Z) and the assumed Expected Allowable Long-Term Costs of Continued Trojan Operation (Y). Ultimately, the Commission made determinations regarding these assumptions (see pages 34-52 of Order No. 95-322) to develop the final net benefit determination of negative $20.4 million (after-tax).

Q. What did this mean?

A. It meant that the Commission concluded that the immediate shut-down of Trojan was $20.4 million more costly than continued operation of the plant under the assumptions the Commission adopted. Thus, to provide a net customer benefit, the Commission required PGE to write-off $20.4 million (after-tax) of Trojan investment.

Q. Did PGE make the required write-off?

A. Yes. PGE wrote-down the unamortized balance of Trojan by $27 million to create the necessary after-tax write-off of $20.4 million.

Q. How does the Court of Appeals' interpretation affect the net benefits analysis?

A. The UE 88 net benefits test assumed that the value of the unamortized Trojan investment balance under the closure scenario and the continued operation scenario was the same (*i.e.*, the "X" term above). If rates could include a return on the Trojan investment under both scenarios, this assumption is reasonable. However, under the Court of Appeals' interpretation, the value of the unamortized investment (X) is no longer equal under the "closure" and "continued operation" scenarios.

Q. Please explain.

A. Under the assumptions the Commission used in UE 88, if PGE were to continue to operate Trojan, rates would include recovery of and a return on the unamortized investment in Trojan. However, if Trojan is closed, the Court of Appeals interpretation requires that rates only include recovery of the unamortized investment in the plant, with no return on. Thus, the treatment of the unamortized (or sunk) investment is not the same and therefore the unamortized investment (X) is not the same on both sides of the net benefits test. This is a direct result of the Court of Appeals' interpretation.

Q. How does the court's interpretation alter the net benefit test results?

A. The impact of customers not paying a return on is a function of both the amortization period and whether the prohibited return on is defined as the full return on or only the equity return component. The longer the amortization period with no "return on," the greater the "benefit" of the Trojan closure to customers. Also, as we have indicated before, we believe that return on should refer only to the equity return component and that debt costs should still be recoverable. However, we have done our analysis conservatively to assume the broader definition of "return on." The Commission should take into account the impact of the Court of Appeals' interpretation on the net benefits test by calculating the present value of the unamortized investment collected over any assumed amortization period. This will effectively calculate the benefit to customers under a closure scenario in which they would be responsible for recovery of the investment but not a return on the investment. Conceptually, the net benefits test can be written as:

Y > Z – X' where

X'= The difference between full recovery and the present value of providing recovery of, but no return on over a given amortization period.
Y = Expected Allowable Long-Term Costs of continued Trojan Operation
Z = Replacement Resource Costs

Q. Has PGE performed these calculations?

A. Yes, we have calculated the present value recovery of the investment with no return on under both a one-year amortization period and a 17-year recovery period. Under a one-year amortization period, by forgoing a "return on," the benefits to customers of the closure scenario increase by $23 million in present value terms. Under a 17-year recovery period, the benefits to customers of the closure scenario increase by $182 million.

Q. How much benefit do customers experience from the Trojan closure under either a 17-year recovery period or one-year recovery?

A. Under a 17-year recovery period, customers experience approximately $155 million in net benefit ($182 million - $27 million = $155 million). Under a one-year recovery period, customers experience approximately -$4 million in net benefit ($23 million - $27 million = -$4 million).

Q. Are there any other changes in the net benefits analysis that you propose?

A. Yes, the treatment of the costs to replace the steam generator.

Q. How did the Commission treat the replacement cost of steam generators in the UE 88 net benefits test?

A. The Commission excluded the cost of steam generators from the "continued Trojan operation" scenario. As Ms. Lesh's testimony explains (PGE Exhibit 6000, Section IV. C), PGE believes good grounds exist to revisit this decision.

Q. If the steam generator replacement is included in the "continued Trojan operation" scenario, please state how much customers benefited from the Trojan closure under both the 17-year recovery period and the one-year recovery period.

A. In the net benefit test performed in UE 88, the assumption that the steam generator replacement could not be included resulted in a $183 million reduction in the net benefits of the Trojan closure. Thus, if the Commission ruled that the steam generators were recoverable under the "continued operation of Trojan" scenario, the net benefit of Trojan closure would increase by $183 million. For a one-year amortization of Trojan, this would increase the net benefit of Trojan closure from negative $4 million to positive $179 million ($183 million - $4 million = $179 million). For the 17-year recovery period alternative, this would increase the net benefit of closing Trojan from positive $155 million to positive $338 million ($183 million + $155 million = $338 million).

V. Application of the Net Benefit Analysis

Q. How do the figures above alter the net benefits test and the amount of the Trojan balance?

A. First, we propose reversal of the disallowance of $27 million ruling in UE 88 that was based solely on the outcome of the net benefit test.

Under a one-year amortization period, the economic impact of the Court of Appeals' interpretation on the net benefits test is to reverse the net benefit from negative $27 million to negative $4 million. Thus, a reversal of $23 million of the $27 million write-off is required by application of the net benefits test used in UE 88.

Under a 17-year recovery period, the required revision to the net benefits test is to reverse the net benefit from negative $27 million to a positive net benefit of $155 million. Thus, we conclude that the net benefit of Trojan closure under scenarios that assume a 17-year collection period of Trojan requires the reversal of the entire $27 million disallowance in UE 88.

Q. The Commission also disallowed $27 million of Trojan investment in UE 88 for plugging and sleeving costs as well as a spare reactor coolant pump. Are these disallowances impacted by a reconsideration of the net benefit test for the impact of receiving no return on?

A. No. The disallowances were associated with decisions on PGE prudence made by the Commission that should not be impacted by this remand proceeding. By contrast, the write-off associated with the net benefit test was purely the result of the assumptions made in the application of the test.

Q. What impact would this restated net benefits test have on the unamortized Trojan balance?

A. Under the 17-year recovery period, the unamortized balance would be $367 million, as of the effective date of the UE 88 final order. Under the one-year recovery period, the unamortized Trojan balance would be $363 million.

Q. What effect would this change to the unamortized Trojan balance have had on the revenue requirements approved in UE 88, UE 93, and UE 100?

A. Under a one-year recovery period scenario, the impact would be a $23 million increase in the revenue requirement for the one-year recovery period. Under the 17-year recovery period scenario, the impact would be to increase the revenue requirement by $27 million collected over 17 years. Over the period April 1, 1995 through September 30, 2000, the 17-year scenario would have resulted in an additional recovery of $8.8 million.

Q. What is the positive benefit created by the decision to close Trojan if the "continued operation" scenario recognizes that PGE would need to replace its steam generators?

A. As explained above, under the 17-year recovery period, customers would experience a total net benefit of $338 million. Under a one-year recovery period, customers would receive $179 million in net benefit.

Q. How do you suggest the Commission could use these positive benefits created by PGE's decision to shutdown Trojan?

A. The Commission could decide that a sharing of the savings that resulted from the net benefit of closing Trojan is appropriate.

Q. How might the Commission have applied such a policy in this case?

A. In this case, the Commission could consider the net savings of Trojan closure relative to continued operation as a benefit to customers that should be shared with the utility.

Q. What effect would this decision have had on the revenue requirements in UE 88, UE 93, and UE 100?

A. Under a one-year amortization of Trojan, there are no net benefits to share unless the steam generators are considered recoverable under the "continued Trojan operation" scenario. As we addressed earlier, the net benefit of the early retirement of Trojan under a one-year recovery period is $179 million assuming the steam generators are recoverable. If the Commission were to apply a 20% sharing to the net benefit of $179 million, PGE would be allowed to collect approximately $36 million, which would increase the revenue requirement by that amount over the period collected. The 20% and other possible sharing percentages are discussed by Ms. Lesh in PGE Exhibit 6000, Section IV. C.

Under the 17-year recovery period approach, the Commission has multiple options. First, notwithstanding the treatment of steam generator replacement under continued operation, the Commission could allow the utility to share 20% of the savings that results from the net financial benefit of the Trojan closure of $155 million, or $31 million. If collected over 17 years, this would increase PGE's revenue requirement by approximately $10 million over the period April 1, 1995 through September 30, 2000.

Alternatively, the Commission could rule that a sharing of the savings is appropriate that reflects the assumption that the replacement steam generators would be recoverable under the "continued Trojan operation" scenario. Under this case, PGE could be awarded 20% of $338 million, or $68 million. If collected over 17 years, this would increase PGE's revenue requirement by approximately $22 million over the period April 1, 1995 through September 30, 2000.

VI. Plant Classification

Q. For what plant is PGE suggesting the Commission reconsider the proper classification?

A. As shown in PGE Exhibit 6300, there is certain Trojan plant that continued to provide service to customers, even after Trojan was no longer producing electricity. This service includes protecting the public safety as well as providing for mandated decommissioning of the site.

Q. What useful life would the Commission use for these plant balances?

A. We assume that any plant classified as plant-in-service, rather than abandoned, should be recoverable, with "return on," over 17 years through 2011.

Q. What effect would this classification have on the revenue requirements in UE 88, UE 93, and UE 100?

A. Collecting approximately $80 million of plant classified as in service, with a return on over 17 years, increases PGE's revenue requirement by $70 million over the period April 1, 1995 through September 30, 2000.

Q. Would this classification affect the application of any of the other Building Blocks?

A. Yes. Many of the Building Blocks have interrelated effects. For the purposes of this discussion, we highlight only the incremental impacts of the item discussed. For example, if a portion of the Trojan investment were classified as plant-in-service <u>and</u> the Commission ruled on remand that a one-year amortization period applied along with a 25 basis point increase in ROE, the basis point increase would impact the return on the plant classified as plant-in-service. PGE Exhibit 6201 summarizes the incremental revenue requirement effects of the tools outlined in this testimony over the period April 1, 1995 through September 30, 2000.

VII. Balance Sheet Options

Q. Were there credits available at the time of the UE 88 final order that the Commission could have used to reduce the Trojan balance?

A. Yes.

Q. What were those credits?

A. There was only one credit available at the time, the Boardman gain. This was a customer credit to reflect the gain from the sale of a portion of the Boardman facility by PGE in 1985.

Q. What would the remaining Trojan investment for amortization have been if the Commission had used this balance as an offset against the Trojan balance?

A. The Commission could have used the balance of the Boardman credit of approximately $111 million at April 1, 1995 to reduce the unamortized balance of Trojan. As a result, the unamortized balance of Trojan would have decreased from $340 million, after the UE 88 disallowances, to approximately $229 million.

Q. Was the Boardman gain used later against other regulatory assets?

A. Yes. Just eight months later, in UE 93 (Order No. 95-1216), the Commission approved offsetting the Boardman gain against AMAX, SAVE, and Trojan Replacement power cost deferrals. In addition, a residual portion of the Boardman gain was used then to reduce the Trojan investment balance.

Q. If the Commission determines that it would have used the entire Boardman gain to reduce the Trojan balance in UE 88, what do you propose to do with those regulatory assets?

A. If the Boardman gain were used, in its entirety, to reduce the Trojan balance in UE 88, the AMAX, SAVE, and the Trojan Replacement power costs deferrals would have to be collected, with a return, over some period of time. The recovery period of these regulatory assets is largely a function of the Commission's goals of achieving rate stability and intergenerational equity across time. In PGE Exhibit 6000, Section V, Ms. Lesh suggests that the Commission ought to use a three year amortization period for these regulatory assets if it chooses to allow a 17-year amortization period for Trojan. However, if the Commission elects a one-year amortization period for Trojan, the Commission should elect a longer period of amortization of these regulatory assets (10 years) to improve rate stability and intergenerational equity.

VIII. Deferral of Power Costs

Q. Are there other Building Blocks available to the Commission under the one-year recovery period alternative?

A. As described in PGE Exhibit 6000, Section IV. F, the Commission could have authorized deferral of a portion of net variable power costs authorized over the one-year period beginning April 1, 1995.

Q. What were PGE's forecasted net variable power costs in UE 88?

A. The UE 88 rates were established to collect $309 million in annual net variable power costs.

Q. What would the impact have been on PGE's revenue requirement in UE 88?

A. To the extent UE 88 power costs were deferred, the revenue requirement in UE 88 would have been lower and collections from customers during the recovery period of the deferred balance would have been higher. The financial impact of a power cost deferral depends upon the amount deferred and the amortization period selected.

IX. Ratemaking Approaches Combining Various Building Blocks

Q. What Building Block combinations do you discuss in this section of your testimony?

A. We analyze in detail three approaches:

A. Approach I: One-Year Recovery and Restoration of UE 88 Disallowance

Q. What is the first approach?

A. The first approach is based on the following factual and policy decisions:

- Adoption of a one-year amortization period for the un-depreciated Trojan investment; and
- Calculation of the net benefits test based on a one-year amortization period with no return on, resulting in a partial restoration of the UE 88 write-off.

Q. Do you have an exhibit that shows the financial impact of this alternative throughout the five and one-half year period from UE 88 through UM 989?

A. Yes. The exhibit is PGE Exhibit 6202, Page 1.

Q. Can you please describe in detail that exhibit?

A. Yes. Column A of PGE Exhibit 6202, Page 1, shows the UE 88 revenue requirement compared with the UE 88 revenue requirement computed under this alternative for the UE 88 rate period from April 1, 1995, through November 27, 1995. Column B shows the UE 93 revenue requirement compared with the UE 93 revenue requirement computed under this alternative for the UE 93 rate period from November 28, 1995, through March 31, 1996. The purpose of this column is to show the financial impact for recovery of Trojan in one year. Column C shows the UE 93 revenue requirement compared with the UE 93 revenue requirement computed under this alternative for the remainder of the UE 93 rate period from April 1, 1996, through November 30, 1996. Column D shows the UE 100 revenue requirement compared with the UE 100 revenue requirement computed under this alternative for the UE 100 rate period from December 1, 1996 through September 30, 2000. Column E repeats Column A. Column F is the sum of Columns A and B. Column G is the sum of Columns A through D. Line 13 at the bottom of PGE Exhibit 6202, Page 1, shows what customers would have owed PGE at the time of the UM 989 settlement under this alternative.

Q. Do you have a table that summarizes this exhibit?

A. Yes. Table 1 below summarizes the key points of the PGE Exhibit 6202, Page 1.

Table 1
($000)

Period (All Begin 4/1/95)	Approved Revenue Requirement	Scenario Revenue Requirement	Revenue Requirement Difference
8 Months	56,502	239,153	182,651
1 Year	77,840	363,270	285,430
5.5 Years	298,187	363,270	65,083

It sets forth the revenue requirement differences during (1) the eight month period in which UE 88 rates were effective (Column A of PGE Exhibit 6202, Page 1), (2) the one-year period from April 1995 through March 1996 (Column F of PGE Exhibit 6202, Page 1), and (3) the five and a half year period from April 1995 through September 30, 2000 (Column G of PGE Exhibit 6202, Page 1).

Q. What does Table 1 show in terms of the revenue requirement under this alternative?

A. It shows that the revenue requirement under this alternative is substantially more than the approved revenue requirement. For example, during the one year following the effective date of UE 88 rates, the revenue requirement would have been in excess of $285 million more than the approved revenue requirement. Over the entire five and one-half year period, the revenue requirement under this approach would have been approximately $65 million more than the approved revenue requirement.

Q. What would PGE have been owed as of September 30, 2000?

A. PGE would have been owed approximately $183 million, as shown on line 14 of PGE Exhibit 6202, Page 1.

Q. Why is the amount customers would have owed PGE ($183 million) higher than the difference in the revenue requirements ($65 million)?

A. This reflects the fact that interest applies to the difference in revenue requirements. Under this scenario, most of the difference in revenue requirements occurs in 1995 and early 1996, when the revenue requirement would have been more than $285 million above the approved revenue requirement during the period. The interest rate used is PGE's authorized cost capital at that time.

Q. Under Approach 1, what conclusions do you draw regarding the final orders in UE 88 and UM 989?

A. This shows that there were no excess payments made by customers during the period April 1, 1995 to September 30, 2000. Under this scenario, revenue requirement would have been higher during the UE 88 rate period. In addition, the UM 989 settlement is still reasonable and a benefit to customers. In the UM 989 settlement, the Trojan balance of $180 million was offset against customer credits of $161 million. Under Approach 1, the Trojan balance is recovered in one year but customers owe PGE about $183 million at the time of the UM 989 settlement. Eliminating this $183 million customer liability by offsetting it against $161 million in customer credits still would provide customers with a substantial benefit.

B. Approach II: One-Year Recovery and Other Building Blocks

Q. What is the second combination of Building Blocks that you analyze in detail?

A. This second approach involves the following factual and policy decisions from UE 88:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation, and including the effects of the Court of Appeals' interpretation in the costs of closure and of steam generator replacement in the cost of continued operation.
- Leave $80 million of the Trojan assets in the plant in service accounts.
- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not plant in service and amortize the remaining balance over one year.
- Authorize a required return on equity of 11.85 percent.
- Defer a portion of PGE's 1995 and 1996 (four months, to match the period of Trojan recovery) net variable power costs, for recovery over the subsequent ten years;
- Recover the AMAX termination payment, pre-UE 88 deferred power costs, and SAVE incentive over the same ten years.

Q. To what rate base items does the increased ROE apply?

A. PGE's cost of capital would apply to PGE's rate base except for that portion of the Trojan investment that is classified as abandoned plant. It also would apply to interest on the regulatory assets under this approach.

Q. What is the balance of the power cost deferral?

A. The power cost deferral balance is $138 million.

Q. Why did you select this amount?

A. We selected this amount to improve the matching of costs and benefits of Trojan closure and achieve better rate stability, given recovery of the Trojan balance in one year.

Q. What is the financial impact of this approach?

A. Table 2 sets forth under this alternative the revenue requirement differences during (1) the eight month period in which UE 88 rate were effective (Column A of PGE Exhibit 6202, Page 2), (2) the one-year period from April 1995 through March 1996 (Column F of PGE Exhibit 6202, Page 2), and (3) the five and one-half year period from April 1995 through September 30, 2000 (Column G of PGE Exhibit 6202, Page 2).

Table 2
($000)

Period (All Begin 4/1/95)	Approved Revenue Requirement	Scenario Revenue Requirement	Revenue Requirement Difference
8 Months	260,125	266,606	6,482
1 Year	387,140	403,252	16,112
5.5 Years	607,487	626,446	18,959

Under this alternative, PGE's revenue requirement in UE 88 would have been slightly higher than the approved UE 88 revenue requirement ($6 million) and customers would have owed PGE about $198 million as of September 30, 2000.

Q. What is the basis for your conclusion?

A. PGE Exhibit 6202, Page 2, shows our analysis. The columns of PGE Exhibit 6202, Page 2, are the same as those set forth in PGE Exhibit 6202, Page 1.

Q. Please compare the approved UE 88, UE 93 and UE 100 revenue requirements with the corresponding revenue requirements under this approach.

A. As shown in Table 2, the revenue requirements under this approach are very similar to the approved revenue requirements. They differ by only $19 million over the five and one-half year period beginning April 1, 1995, which is less than one-half percent of the approved revenue requirement. This shows that the power cost deferral works to mitigate the impact of shortening the Trojan recovery period to one-year.

Q. What is the September 30, 2000 balance customers would have owed under this alternative?

A. It is $198 million, as shown on line 21 of PGE Exhibit 6202, Page 2.

Q. What is the basis for this balance?

A. The balance is composed of three pieces. First, the remaining balance of the Trojan plant classified as in service is about $42 million. Second, the balance for the regulatory assets (AMAX, SAVE, and Trojan replacement power cost deferrals) and the power cost deferral is about $127 million. Third, the revenue requirement under this scenario exceeds the approved revenue requirement by about $19 million plus applicable interest of $10 million. The total balance is the sum of these three component parts.

Q. Do you recommend this approach?

A. Yes, as discussed in PGE Exhibit 6000, Section V.

Q. What conclusions do you draw regarding the final orders in UE 88 and UM 989?

A. There were no excess payments from customers in UE 88 because the revenue requirement under this alternative is greater than the approved UE 88 revenue requirement. The UM 989 final order should be affirmed. Customers owe PGE $198 million under this alternative as of September 30, 2000, as compared with the Trojan balance of $180 million used in the UM 989 settlement. The UM 989 settlement looks more favorable to customers under this alternative because it uses $161 in customer credits to eliminate a $198 million customer liability.

C. Approach III: 17-Year Recovery Period and Other Building Blocks

Q. Please describe the third approach.

A. Under this third approach we use the following Building Blocks:

- Recover the entire un-depreciated investment in Trojan, based on the positive net benefit resulting from comparing the cost of closure to the cost of continued operation, and including the effects of the Court of Appeals' interpretation in the costs of closure and of the steam generator replacement in the cost of continued operation.
- Receive 20 percent of the positive net benefit created through the economic retirement of Trojan, spread evenly over 17 years.
- Leave $80 million of the Trojan assets in plant in service accounts.
- Offset the $111 million Boardman gain against the un-depreciated Trojan assets that were not plant in service.
- Authorize a required return on equity of 13.1 percent.
- Recover the AMAX termination payment, pre-UE 88 deferred power costs, and SAVE incentive over the three subsequent years.

Q. Why did you shorten the recovery period for the regulatory assets in this alternative and eliminate the power cost deferral used in the second alternative?

A. In this approach, PGE is recovering the Trojan investment over 17 years instead of one; therefore no need exists to spread recovery of the regulatory assets over an extended period of time or for the power cost deferral. The 3-year amortization period is an appropriate choice for the Commission under this approach.

Q. How did PGE perform the net benefit test for this scenario?

A. In this scenario, we needed to take into account the portion of the Trojan asset that is plant in service and the reduction in the Trojan balance by the Boardman offset. Under this approach, the unamortized portion of the Trojan balance that remains classified as abandoned plant is $176 million after restoration of the disallowed amount in UE 88. The net benefit to customers of the Trojan shutdown is $256 million.

Q. How much of this benefit is shared with PGE?

A. PGE would receive 20% of the savings, which is consistent with Commission practice and precedent as discussed in PGE Exhibit 6000, Section IV. C.

Q. What is the impact on PGE's revenue requirement of this approach?

A. Table 3 sets forth under this alternative the revenue requirement differences during (1) the eight month period in which UE 88 rate were effective (Column A of PGE Exhibit 6202, Page 3), (2) the one-year period from April 1995 through March 1996 (Column F of PGE Exhibit 6202, Page 3), and (3) the five and one-half year period from April 1995 through September 30, 2000 (Column G of PGE Exhibit 6202, Page 3).

Table 3
($000)

Period (All Begin 4/1/95)	Approved Revenue Requirement	Scenario Revenue Requirement	Revenue Requirement Difference
8 Months	56.502	56,564	63
1 Year	77,840	85,017	7,177
5.5 Years	298,187	356,661	58,474

Under this approach, PGE's revenue requirement is quite close to the approved revenue requirements in UE 88, UE 93, and UE 100. For the five and a half year period, the revenue requirement would have been about $58 million more than the approved revenue requirement, or about one percent of the authorized revenue requirement.

Q. What is the impact on the UE 88 revenue requirement?

A. The UE 88 revenue requirement under this alternative is virtually identical to the approved UE 88 revenue requirement. This alternative would increase the revenue requirement by about $63,000.

Q. What is the balance owed to PGE as of September 30, 2000, under this alternative?

A. The balance is about $275 million, as shown on PGE Exhibit 6202, Page 3, line 20.

Q. How did you calculate the balance?

A. The balance has three parts. First, the unamortized Trojan plant is about $161 million (almost $43 million classified as plant-in-service and $118 million classified as abandoned). Second, there remains about $34 million of the share-the-savings to collect. Third, the revenue requirement under this scenario exceeds the approved revenue requirement by about $58 million plus interest of $22 million.

Q. Do you recommend this alternative?

A. Yes, as discussed in PGE Exhibit 6000. However, this approach is only recommended if the Commission approves a 17-year amortization period for Trojan.

Q. What conclusions do you draw regarding the final orders in UE 88 and UM 989 based upon this alternative?

A. During the UE 88 rate period customers did not make excess payments and the UM 989 settlement is reasonable and should be affirmed. Under this alternative, PGE's revenue requirement in UE 88 would have been higher and the customer liability eliminated by the UM 989 settlement ($275 million) would have been even greater than the $180 million in Trojan unamortized balance offset against $161 million in customer credits.

X. Qualifications

Q. Mr. Tinker, please describe your qualifications.

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. Mr. Schue, please summarize 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). Most recently, I worked on PGE's 2002 IRP and related Request for Proposals. In addition, I worked at the Oregon Public Utility Commission during 1986 and 1987, where my primary assignment was the economic analysis of conservation programs.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
6201	Incremental Revenue Requirement Effects of Tools Available to the Commission
6202	Results of Revenue Requirement Approaches

PGE Exhibit 6201
Dollars in $000s

		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	Revenue Requirement Per Rate Orders							
1	Return On	22,146	10,164	18,881	87,319	22,146	32,310	138,510
2	Recovery Of	34,356	11,174	17,042	97,105	34,356	45,530	159,677
3								
4	**One-Year Amortization**							
5	Return	(22,146)	(10,164)	(18,881)	(87,319)	(22,146)	(32,310)	(138,510)
6	Return On Equity Only	(15,798)	(7,254)	(13,474)	(62,316)	(15,798)	(23,051)	(98,841)
7	ROE 25 Basis Points	1,753	1,075	2,097	12,056	1,753	2,827	16,980
8								
9	Trojan Balance Over One Year	223,940	116,222	-	-	223,940	340,162	340,162
10	Boardman Offset Over One Year	(73,174)	(37,977)	-	-	(73,174)	(111,151)	(111,151)
11	Reg. Assets -- Troj. Repl. Pow, AMAX, SAVE - 17 Years	7,232	3,753	7,323	42,109	7,232	10,985	60,417
12	Collect Def. Power Costs Over 17 Years	18,638	9,673	18,874	108,525	18,638	28,311	155,710
13	First Year Power Costs	40,370	20,951	-	-	40,370	61,321	61,321
14								
15	Net-Benefits							
16	Reversal of $23,108 of Disallowance	15,213	7,895	-	-	15,213	23,108	23,108
17	Reversal of $183,100 SG Disallowance	120,541	62,559	-	-	120,541	183,100	183,100
18	Share SG-Related "80/20"	24,108	12,512	-	-	24,108	36,620	36,620
19								
20	Plant in Service							
21	Collect Trojan Plant in Service Over 17 Years							
22	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
23	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
24	Collect Non-Plant in Service Trojan Over One Year	171,142	88,820	-	-	171,142	259,962	259,962

PGE Exhibit 6201
Dollars in $000s

		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	17-Year Amortization							
1	Return	(22,146)	(10,164)	(18,881)	(87,319)	(22,146)	(32,310)	(138,510)
2	Return on Equity only	(15,798)	(7,254)	(13,474)	(62,316)	(15,798)	(23,051)	(98,841)
3	ROE 150 Basis Points	10,517	6,447	12,580	72,336	10,517	16,965	101,881
4	Capital Structure - Shift 10% Debt to Equity	10,344	5,368	10,475	60,230	10,344	15,712	86,417
5	Recovery of Debt Costs	5,854	2,958	5,598	27,489	5,854	8,812	41,898
6								
7	Trojan Balance Over 17 Years	13,370	6,939	13,539	77,848	13,370	20,308	111,695
8								
9	Plant in Service							
10	Collect Trojan Plant in Service Over 17 Years							
11	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
12	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
13	Collect Non-Plant in Service Trojan Over One Year	10,217	5,303	10,347	59,494	10,217	15,520	85,361
14								
15	Net-Benefits							
16	Reversal of $26,828 Disallowance	1,054	547	1,068	6,140	1,054	1,602	8,809
17	Share "Net""No Return On" Savings "80/20"	1,220	633	1,235	7,103	1,220	1,853	10,192
18	Share "Net" No Return on Savings After Bdman and In Svc "80/20"	512	266	518	2,980	512	777	4,276
19	Share "Net" "No Ret. On Equity" Savings "80/20"	827	429	837	4,814	827	1,256	6,907
20	Reversal of $183,100 SG Disallowance	1,439	747	1,458	8,381	1,439	2,186	12,024

PGE Exhibit 6202
Dollars in $000s

		A	B	C	D	E (E = A)	F (F = A + B)	G (G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	One-Year Trojan Collection and Restoration							
	Scenario Revenue Requirement:							
1	One-Year Amortization	223,940	116,222	-	-	223,940	340,162	340,162
2	Restoration of UE 88 Write-Off	15,213	7,895	-	-	15,213	23,108	23,108
3	Total Scenario Revenue Requirement Collections	239,153	124,117	-	-	239,153	363,270	363,270
4								
5	**Revenue Requirement per Rate Cases:**							
6	Trojan Revenue Requirement	56,502	21,338	35,923	184,424	56,502	77,840	298,187
7	Revenue Requirement Difference	182,651	102,779	(35,923)	(184,424)	182,651	285,430	65,083
8								
9								

10	Derivation of Balance Owed PGE @ 9/30/2000:	
11		
12	65,083	Revenue Requirement Differential (Scenario Revenue Requirement Less Trojan Revenue Requirement)
13	118,409	Interest on Revenue Requirement Differential
14	183,492	Balance Owed PGE @ 9/30/2000

PGE Exhibit 6202
Dollars in $000s

#		A	B	C	D	E	F	G
						(E = A)	(F = A + B)	(G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	One Year Collection of Trojan with Other Changes:							
	Scenario Revenue Requirement:							
1	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
2	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
3	25 Basis Pts. ROE Increase	1,825	1,110	2,166	12,456	1,825	2,935	17,557
4	Collection of Trojan and 26.8, Net of Plant In-Service and Board., Over One Year	115,629	60,010	-	-	115,629	175,639	175,639
5	First Year Power Costs	112,918	58,603	-	-	112,918	171,521	171,521
6	Reg. Assets Collection Over 10 Years	9,424	4,891	9,544	54,877	9,424	14,316	78,736
7	Deferred First-Year Power Cost Collection Over 10 Years	13,489	7,000	13,659	78,541	13,489	20,489	112,689
8	Total Scenario Revenue Requirement Changes	266,606	136,646	33,839	189,355	266,606	403,252	626,446
9								
10	**Revenue Requirement per Rate Cases:**							
11	First Year Power Costs	203,623	105,678	-	-	203,623	309,300	309,300
12	Trojan Revenue Requirement	56,502	21,338	35,923	184,424	56,502	77,840	298,187
13	Trojan and Power Cost Revenue Requirement	260,124	127,016	35,923	184,424	260,124	387,140	607,487
14								
15	Revenue Requirement Difference	6,482	9,630	(2,084)	4,931	6,482	16,112	18,959
16								
17								

#		
18	Derivation of Balance Owed PGE @ 9/30/2000:	
19	80,200	Trojan Plant in Service Balance @ 04/01/95
20	(37,647)	Recovery of Plant in Service Balance Over Period 04/01/95 - 09/30/00
21	18,959	Revenue Requirement Differential (Scenario Revenue Requirement Less Trojan & Pwr Cost Rev. Req.)
22	9,712	Interest on Revenue Requirement Differential
23	126,998	Remaining Balance for Reg Assets and Deferred Power Costs @ 09/30/00
24	198,222	Balance Owed PGE @ 9/30/2000

PGE Exhibit 6202
Dollars in $000s

		A	B	C	D	E (E = A)	F (F = A + B)	G (G=A+B+C+D)
	Start of Period	04/01/95	11/28/95	04/01/96	12/01/96	"8-month"	"One-Year"	"5.5 Year"
	End of Period	11/27/95	03/31/96	11/30/96	09/30/00	Impact	Impact	Impact
	Number of Months	7.90	4.10	8	46	7.90	12	66
	Docket	UE 88	UE 93	UE 93	UE 100			
	Annual Revenue Requirement ($000)	943,333	995,498	995,498	958,669			
	Period Revenue Requirement ($000)	621,028	340,128	663,665	3,674,898			
	17 Year Collection of Trojan with Other Changes:							
	Scenario Revenue Requirement:							
1	Plant in Service - Return On	5,221	2,396	4,452	20,587	5,221	7,618	32,657
2	Plant in Service - Recovery Of	8,100	2,635	4,018	22,894	8,100	10,735	37,647
3	150 Basis Pts. ROE Increase	10,948	6,661	12,998	74,736	10,948	17,609	105,343
4	20% STS (Based on SG, Return Foregone Net of Bdmn, Net of 26.8)	2,010	1,043	2,035	11,702	2,010	3,053	16,790
5	Collection of Trojan and 26.8, Net of Plant In-Service and Board., Over 17 Years	6,903	3,583	6,991	40,196	6,903	10,486	57,673
6	Reg. Assets (AMAX, SAVE, Troj Repl NVPC Over 3 Years)	23,382	12,135	23,678	47,357	23,382	35,518	106,553
7	Total Scenario Revenue Requirement Changes	56,564	28,453	54,171	217,473	56,564	85,017	356,661
8	**Revenue Requirement per Rate Cases:**							
9	Trojan Revenue Requirement	56,502	21,338	35,923	184,424	56,502	77,840	298,187
10	Revenue Requirement Difference	63	7,115	18,249	33,048	63	7,177	58,474
11								

12	Derivation of Balance Owed PGE @ 9/30/2000:	
13	80,200	Trojan Plant in Service Balance @ 4/1/1995
14	(37,647)	Recovery of Plant in Service Balance Over Period 04/01/95 - 09/30/00
15	58,474	Revenue Requirement Differential (Scenario Revenue Requirement Less Trojan Revenue Requirement)
16	21,578	Interest on Revenue Requirement Differential
17	175,639	04/01/95 Balance, Net of Boardman Gain and Plant in Service, with Restoration
18	(57,673)	Payments on Net Trojan Balance Over Period 04/01/95 - 09/30/00
19	34,343	Remaining STS Balance 09/30/00
20	274,915	Balance Owed PGE @ 9/30/2000

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE-88 REMAND

PORTLAND GENERAL ELECTRIC COMPANY

Work Papers of

Jay Tinker
Stephen Schue
Patrick G. Hager

Portland General Electric

February 15, 2005

UE-88 REMAND / PGE EXHIBIT / 6200
TINKER - SCHUE - HAGER

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Quantitative Analysis

PORTLAND GENERAL ELECTRIC COMPANY

WORK PAPERS

Jay Tinker
Stephen Schue
Patrick G. Hager

February 15, 2005

PGE Exhibit 6200 (Quantitative Analysis)
Work Papers – Table Of Contents

Net Trojan Plant Investment
From 3/31/1995 through 9/30/2000

Trojan Investment	Before UE-88 Write-Off 03/31/1995	UE-88 Write-Off	UE-88 Write-Off Net Benefit Test	After UE-88 Write-off 03/31/1995	12/31/1995	
FAS 90 Assets						
Net FAS 90 Balance	345,353,482.72	-	(22,773,056.00)	322,580,426.72	301,023,140.45	
Change in FAS 90 Balance (Amortization)	N/A			(22,773,056.00)	(21,557.286.27)	
FAS 71 Assets						
Inspection and Plugging	15,160,208.00	(15,160,208.00)		-	-	
Sleeving Costs	9,658,701.00	(9,658,701.00)		-	-	
Reactor Coolant Pump	2,162,144.00	(2,162,144.00)		-	-	
Other FAS 71 Assets	21,637,002.27		(4,054,994.00)	17,582,008.27	-	
Net FAS 71 Balance	48,618,055.27	(26,981,053.00)	(4,054,994.00)	17,582,008.27	-	
Change in FAS 71 Balance (Amortization)	N/A			(31,036,047.00)	(17,582,008.27)	Per Order 95-1216
Net Trojan Investment	**393,971,537.99**	**(26,981,053.00)**	**(26,828,050.00)**	**340,162,434.99**	**301,023,140.45**	
Change in Net Trojan Investment				**(53,809,103.00)**	**(39,139,294.54)**	

Trojan Investment	12/31/1996	12/31/1997	12/31/1998	12/31/1999	09/30/2000
FAS 90 Assets					
Net FAS 90 Balance	275,460,218.15	251,763,045.03	229,202,119.88	202,682,933.93	180,485,808.72
Change in FAS 90 Balance (Amortization)	(25,562,922.30)	(23,697,173.12)	(22,560,925.15)	(26,519,185.95)	(22,197,125.21)
FAS 71 Assets					
Inspection and Plugging	-	-	-	-	-
Sleeving Costs	-	-	-	-	-
Reactor Coolant Pump	-	-	-	-	-
Other FAS 71 Assets	-	-	-	-	-
Net FAS 71 Balance	-	-	-	-	-
Change in FAS 71 Balance (Amortization)					
Net Trojan Investment	**275,460,218.15**	**251,763,045.03**	**229,202,119.88**	**202,682,933.93**	**180,485,808.72**
Change in Net Trojan Investment	**(25,562,922.30)**	**(23,697,173.12)**	**(22,560,925.15)**	**(26,519,185.95)**	**(22,197,125.21)**

Summary of UE-88 Trojan Write-Off[1]
In Dollars

	3/31/95 Balance Before UE-88 Write-Off	Write-Off Post 1991 Expenditures	Write-Off Additional $20.4 million	3/31/95 Balance After UE-88 Write-Off
Trojan Investment (Pre-tax)	$ 393,971,538	$ (26,981,053)	$ (26,828,050)	$ 340,162,435
Deferred Taxes	$ (83,627,326)	$ 10,673,256	$ 6,428,050	$ (66,526,020)
Trojan Investment Tax Credits	$ (9,756,019)	$ -	$ -	$ (9,756,019)
Trojan Investment (After-tax)	$ 300,588,193	$ (16,307,797)	$ (20,400,000)	$ 263,880,396

1: After the UE-88 write-off, the pre-tax balance of Trojan, $340.2 million, was the remaining investment subject to amortization through 2011, consistent with Order 95-322.

Historical Trojan "Return On"
Based on actual rate base balances
$000s

	4/1/95	12/31/95	12/31/96	12/31/97	12/31/98	12/31/99	09/30/00	10/01/00
Revenue Requirement	34,876	29,931	26,712	24,867	22,593	19,678	17,255	-
Rev Req (Check)	34,876	29,931	26,712	24,867	22,593	19,678	17,255	-
Expenses other than Income Tax	-	-	-	-	-	-	-	-
Income Tax	9,786	8,399	7,499	6,981	6,343	5,524	4,844	-
Total Expenses	9,786	8,399	7,499	6,981	6,343	5,524	4,844	-
Effective Tax Rate Check	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	#DIV/0!
UOI	25,090	21,532	19,213	17,886	16,251	14,154	12,411	-
UOI - Check	25,090	21,532	19,213	17,886	16,251	14,154	12,411	-
Net Trojan Investment	340,162	301,023	275,460	251,763	229,202	202,683	180,486	-
Deferred Taxes	(66,526)	(65,982)	(67,335)	(58,102)	(53,223)	(49,191)	(45,616)	-
Deferred ITC	(9,756)	(8,579)	(7,939)	(7,299)	(6,659)	(6,020)	(5,554)	-
Net Rate Base	263,880	226,462	200,186	186,362	169,320	147,472	129,316	-
Taxes:								
Revenue	34,876	29,931	26,712	24,867	22,593	19,678	17,255	-
Expenses	-	-	-	-	-	-	-	-
Interest Expense	9,998	8,580	7,649	7,121	6,469	5,635	4,941	-
BTI	24,878	21,351	19,063	17,747	16,124	14,043	12,314	-
State Taxes	1,660	1,425	1,272	1,184	1,076	937	822	-
Fed Taxable	23,218	19,926	17,791	16,563	15,048	13,106	11,493	-
Fed Taxes	8,126	6,974	6,227	5,797	5,267	4,587	4,022	-
ITC Amort	-	-	-	-	-	-	-	-
Tax Expense	9,786	8,399	7,499	6,981	6,343	5,524	4,844	-
State Tax Rate	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Federal Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
Combined Tax Rate	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%
Net to Gross Factor	1.648	1.648	1.648	1.648	1.648	1.648	1.648	1.648
Capital Structure:								
Common Equity Cost	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%	11.60%
Preferred Equity Cost	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%
L-T Debt Cost	7.71%	7.71%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
Cost of Capital	9.51%	9.51%	9.60%	9.60%	9.60%	9.60%	9.60%	9.60%
Common Equity Percent	45.44%	45.44%	46.47%	46.47%	46.47%	46.47%	46.47%	46.47%
Preferred Equity Percent	5.42%	5.42%	4.67%	4.67%	4.67%	4.67%	4.67%	4.67%
L-T Debt Percent	49.14%	49.14%	48.86%	48.86%	48.86%	48.86%	48.86%	48.86%
Total Capital Structure	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Tax Rates / Cap Structure Per	UE-88	UE-88	UE-88	UE-88	UE-88	UE-88	UE-88	UE-88
Pre-Tax Weighted CE Cost	8.69%	8.69%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%
Pre-Tax Weighted PE Cost	0.74%	0.74%	0.64%	0.64%	0.64%	0.64%	0.64%	0.64%
Pre-Tax Weighted LT Debt Cost	3.79%	3.79%	3.82%	3.82%	3.82%	3.82%	3.82%	3.82%
Pre-Tax COC	13.22%	13.22%	13.34%	13.34%	13.34%	13.34%	13.34%	13.34%

Historical "Return On" Trojan
Annual Revenue Requirements
Based on Average Rate Base for the Period
$000s

	Annual $$	Adj '95/'00	Debt Share	Equity Share	Check	Debt Share	Equity Share
1995 Beginning 4/1/95	33,640	25,230	7,232	17,997	25,230	28.67%	71.33%
1996	28,321	28,321	8,110	20,212	28,321	28.63%	71.37%
1997	25,789	25,789	7,385	18,405	25,789	28.63%	71.37%
1998	23,730	23,730	6,795	16,935	23,730	28.63%	71.37%
1999	21,136	21,136	6,052	15,083	21,136	28.63%	71.37%
2000 thru 9/30/00	19,072	14,304	4,096	10,208	14,304	28.63%	71.37%
Nominal Totals	151,688	138,510	39,670	98,840	138,510	28.64%	71.36%

UE-88 Cost of Capital
Based on Order 95-322, Appendix F

	UE-88 Authorized		**Plus 25 BP ROE**		**Plus 150 BP ROE**	
	1995 Test Year	1996 Test Year	1995 Test Year	1996 Test Year	1995 Test Year	1996 Test Year
State Tax Rate	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Federal Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
Combined Tax Rate	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%
Net to Gross Factor	1.648	1.648	1.648	1.648	1.648	1.648
Capital Structure:						
Common Equity Cost	11.60%	11.60%	**11.85%**	**11.85%**	**13.10%**	**13.10%**
Preferred Equity Cost	8.27%	8.27%	8.27%	8.27%	8.27%	8.27%
L-T Debt Cost	7.71%	7.82%	7.71%	7.82%	7.71%	7.82%
Cost of Capital	9.51%	9.60%	9.62%	9.71%	10.19%	10.29%
Common Equity Percent	45.44%	46.47%	45.44%	46.47%	45.44%	46.47%
Preferred Equity Percent	5.42%	4.67%	5.42%	4.67%	5.42%	4.67%
L-T Debt Percent	49.14%	48.86%	49.14%	48.86%	49.14%	48.86%
Total Capital Structure	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Tax Rates / Cap Structure Per	UE-88	UE-88	UE-88	UE-88	UE-88	UE-88
Pre-Tax Weighted CE Cost	8.69%	8.89%	8.88%	9.08%	9.81%	10.04%
Pre-Tax Weighted PE Cost	0.74%	0.64%	0.74%	0.64%	0.74%	0.64%
Pre-Tax Weighted LT Debt Cost	3.79%	3.82%	3.79%	3.82%	3.79%	3.82%
Pre-Tax COC	13.22%	13.34%	13.40%	13.53%	14.34%	14.49%

Effect of Changing ROE on Revenue Requirement
Based on Rate Base Balances Per UE-88 and UE-93
Dollars in $000s

1995 Test-Year Ratebase:	1,623,440.00	1996 Test-Year Ratebase:	1,657,947.00	UE 93 Test-Year Ratebase:	1,822,589.00
Trojan Portion:	240,137.00	Trojan Portion:	224,839.00	Trojan Portion:	224,839.00
1995 Test-Year Ratebase Net of Trojan:	1,383,303.00	1996 Test-Year Ratebase Net of Trojan:	1,433,108.00	UE 93 Test-Year Ratebase Net of Trojan:	1,597,750.00
Net to Gross Factor:	1.69436	Net to Gross Factor:	1.69436	Net to Gross Factor:	1.69436
Equity Percentage:	45.44%	Equity Percentage:	46.47%	Equity Percentage:	46.47%
Effect of One-Percent Increase in ROE:	10,650.29	**Effect of One-Percent Increase in ROE:**	11,283.85	**Effect of One-Percent Increase in ROE:**	12,580.19
Effect of 25 BP Change in ROE	2,662.57	**Effect of 25 BP Change in ROE**	2,820.96	**Effect of 25 BP Change in ROE**	3,145.05
Effect of 150 BP Change in ROE	15,975.43	**Effect of 150 BP Change in ROE**	16,925.77	**Effect of 150 BP Change in ROE**	18,870.28

Effect of Changing ROE on Revenue Requirement
Based on Rate Base Balances Per UE-88 and UE-93 (Includes Trojan classified as plant-in-service)
Dollars in $000s

	B4 Class	After Class
1995 Test-Year Ratebase:	1,623,440.00	1,623,440.00
Trojan Portion:	240,137.00	183,519.90
1995 Test-Year Ratebase Net of Trojan:	1,383,303.00	1,439,920.10
Net to Gross Factor:	1.69436	1.69436
Equity Percentage:	45.44%	45.44%
Effect of One-Percent Increase in ROE:	10,650.29	11,086.19
Effect of 25 BP Change in ROE		2,771.55
Effect of 150 BP Change in ROE		16,629.29

	B4 Class	After Class
1996 Test-Year Ratebase:	1,657,947.00	1,657,947.00
Trojan Portion:	224,839.00	171,828.71
1996 Test-Year Ratebase Net of Trojan:	1,433,108.00	1,486,118.29
Net to Gross Factor:	1.69436	1.69436
Equity Percentage:	46.47%	46.47%
Effect of One-Percent Increase in ROE:	11,283.85	11,701.24
Effect of 25 BP Change in ROE		2,925.31
Effect of 150 BP Change in ROE		17,551.85

	B4 Class	After Class
UE 93 Test-Year Ratebase:	1,822,589.00	1,822,589.00
Trojan Portion:	224,839.00	171,828.71
UE 93 Test-Year Ratebase Net of Trojan:	1,597,750.00	1,650,760.29
Net to Gross Factor:	1.69436	1.69436
Equity Percentage:	46.47%	46.47%
Effect of One-Percent Increase in ROE:	12,580.19	12,997.58
Effect of 25 BP Change in ROE		3,249.39
Effect of 150 BP Change in ROE		19,496.36

Rev. Req. Model
Inputs in yellow
Figures Based on UE-88 - 1995 Test Year (Order 95-322)

	At Current Rates	Additional Rev for 11.6% ROE	Proposed
1 Sales to Consumers	886,103	47,162	933,265
2 Sales for Resale	-		-
3 Other Revenues	10,795		10,795
4 Total Operating Revenues	896,898	47,162	944,060
5 Net Variable Power Costs	306,799		306,799
6 Fixed Power Costs	71,532		71,532
7 Other O&M	134,640	1,193	135,833
8 Total Operating & Maintenance	512,971	1,193	514,164
9 Depreciation/Amort	146,882		146,882
10 Taxes Other Than Income	48,579		48,579
11 Utility Income Tax	61,958	18,121	80,079
12 Total Operating Expenses & Taxes	770,390	19,314	789,704
13 **Utility Operating Income**	126,508	27,848	154,356
14 **Average Rate Base**			
15 Rate Base	1,585,834		1,585,834
16 Working Cash	36,726	879	37,605
17 **Average Rate Base**	1,622,560	879	1,623,439
18 **Rate of Return**	7.80%		9.51%
19 **Implied Return on Equity**	7.83%		11.60%
20 Effective Cost of Debt	7.710%	7.710%	7.710%
21 Effective Cost of Preferred	8.270%	8.270%	8.270%
22 Debt Share of Cap Structure	49.14%	49.14%	49.14%
23 Preferred Share of Cap Structure	5.42%	5.42%	5.42%
24 Weighted Cost of Debt	3.789%	3.789%	3.789%
25 Weighted Cost of Preferred	0.448%	0.448%	0.448%
26 Equity Share of Cap Structure	45.44%	45.44%	45.44%
27 State Tax Rate	6.672%	6.672%	6.672%
28 Federal Tax Rate	35.120%	35.120%	35.120%
29 Composite Tax Rate	39.449%	39.449%	39.449%
30 Bad Debt/FF/OPUC Rate	2.530%	2.530%	2.530%
31 Working Cash Factor	4.550%	4.550%	4.550%
32 Gross-Up Factor	1.651	1.651	1.651
33 ROE Target	11.60%	11.60%	11.600%
34 Grossed-Up COC	13.23%	13.23%	13.23%
Utility Income Taxes			
30 Book Revenues	896,898	47,162	944,060
31 Book Expenses	672,077	1,193	673,270
32 Interest Deduction	61,474	33	61,507
33 Deferred Ms	(28,219)	-	(28,219)
34 Book Taxable Income	191,566	45,936	237,502
35 State Taxes	12,781	3,065	15,846
36 State Tax Credits	(166)	-	(166)
37 Net State Taxes	12,615	3,065	15,680
38 Federal Taxable Income	178,951	42,871	221,822
39 Federal Taxes	62,848	15,056	77,904
40 ITC Amort	(1,985)	-	(1,985)
41 Deferred Taxes	(11,520)	-	(11,520)
42 Total Income Tax Expense	61,958	18,121	80,079

45,250.70	(1,911)
47,162.14	
49,073.67	1,912

Rate Base w/Trojan

RB	1,622,560
COE	19.16%
COD	7.710%
Cap Change	1%
Rev Req	1,857

Approx Rate Base w/o Trojan

RB	1,372,560	Trojan about $250 MM
COE	19.16%	
COD	7.710%	
Cap Change	1%	
Rev Req	1,571	

10% Change in Cap Structure (9 months):

Pre-Tax	11,784
After Tax	7,070

Return Foregone if Collected Without Return on Over 17 Years
Trojan Net of Plant Classified as In-Service, Boardman Offset
Uses UE-88 Authorized COC

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)
Net Trojan After-Tax Balance		133,286.68

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
January 1996 -- September 2001:	13.34%
October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
	Mar-95	133,286.68		
1	Apr-95	132,623.57	1,382.81	1,373.12
2	May-95	131,960.45	1,375.92	1,356.69
3	Jun-95	131,297.33	1,369.02	1,340.42
4	Jul-95	130,634.21	1,362.12	1,324.32
5	Aug-95	129,971.10	1,355.23	1,308.38
6	Sep-95	129,307.98	1,348.33	1,292.59
7	Oct-95	128,644.86	1,341.43	1,276.96
8	Nov-95	127,981.74	1,334.54	1,261.49
9	Dec-95	127,318.62	1,327.64	1,246.17
10	Jan-96	126,655.51	1,332.07	1,241.56
11	Feb-96	125,992.39	1,325.11	1,226.42
12	Mar-96	125,329.27	1,318.16	1,211.43
13	Apr-96	124,666.15	1,311.20	1,196.59
14	May-96	124,003.04	1,304.25	1,181.90
15	Jun-96	123,339.92	1,297.29	1,167.35
16	Jul-96	122,676.80	1,290.33	1,152.95
17	Aug-96	122,013.68	1,283.38	1,138.69
18	Sep-96	121,350.56	1,276.42	1,124.58
19	Oct-96	120,687.45	1,269.47	1,110.61
20	Nov-96	120,024.33	1,262.51	1,096.78
21	Dec-96	119,361.21	1,255.55	1,083.09
22	Jan-97	118,698.09	1,248.60	1,069.54
23	Feb-97	118,034.97	1,241.64	1,056.12
24	Mar-97	117,371.86	1,234.69	1,042.84
25	Apr-97	116,708.74	1,227.73	1,029.70
26	May-97	116,045.62	1,220.77	1,016.68
27	Jun-97	115,382.50	1,213.82	1,003.80
28	Jul-97	114,719.39	1,206.86	991.05
29	Aug-97	114,056.27	1,199.91	978.43
30	Sep-97	113,393.15	1,192.95	965.94
31	Oct-97	112,730.03	1,185.99	953.57
32	Nov-97	112,066.91	1,179.04	941.33
33	Dec-97	111,403.80	1,172.08	929.22
34	Jan-98	110,740.68	1,165.13	917.23
35	Feb-98	110,077.56	1,158.17	905.36
36	Mar-98	109,414.44	1,151.21	893.61
37	Apr-98	108,751.32	1,144.26	881.99
38	May-98	108,088.21	1,137.30	870.48
39	Jun-98	107,425.09	1,130.35	859.09
40	Jul-98	106,761.97	1,123.39	847.81
41	Aug-98	106,098.85	1,116.43	836.66
42	Sep-98	105,435.74	1,109.48	825.62

Return Foregone if Collected Without Return on Over 17 Years
Trojan Net of Plant Classified as In-Service, Boardman Offset
Uses UE-88 Authorized COC

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)
Net Trojan After-Tax Balance		133,286.68

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
January 1996 -- September 2001:	13.34%
October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
43	Oct-98	104,772.62	1,102.52	814.69
44	Nov-98	104,109.50	1,095.57	803.87
45	Dec-98	103,446.38	1,088.61	793.17
46	Jan-99	102,783.26	1,081.65	782.57
47	Feb-99	102,120.15	1,074.70	772.09
48	Mar-99	101,457.03	1,067.74	761.71
49	Apr-99	100,793.91	1,060.79	751.44
50	May-99	100,130.79	1,053.83	741.28
51	Jun-99	99,467.68	1,046.87	731.23
52	Jul-99	98,804.56	1,039.92	721.28
53	Aug-99	98,141.44	1,032.96	711.43
54	Sep-99	97,478.32	1,026.01	701.68
55	Oct-99	96,815.20	1,019.05	692.04
56	Nov-99	96,152.09	1,012.09	682.50
57	Dec-99	95,488.97	1,005.14	673.05
58	Jan-00	94,825.85	998.18	663.71
59	Feb-00	94,162.73	991.23	654.46
60	Mar-00	93,499.61	984.27	645.31
61	Apr-00	92,836.50	977.31	636.26
62	May-00	92,173.38	970.36	627.30
63	Jun-00	91,510.26	963.40	618.44
64	Jul-00	90,847.14	956.45	609.67
65	Aug-00	90,184.03	949.49	600.99
66	Sep-00	89,520.91	942.53	592.41
67	Oct-00	88,857.79	935.58	583.91
68	Nov-00	88,194.67	928.62	575.51
69	Dec-00	87,531.55	921.67	567.19
70	Jan-01	86,868.44	914.71	558.96
71	Feb-01	86,205.32	907.75	550.82
72	Mar-01	85,542.20	900.80	542.77
73	Apr-01	84,879.08	893.84	534.80
74	May-01	84,215.97	886.89	526.92
75	Jun-01	83,552.85	879.93	519.12
76	Jul-01	82,889.73	872.97	511.41
77	Aug-01	82,226.61	866.02	503.77
78	Sep-01	81,563.49	859.06	496.22
79	Oct-01	80,900.38	852.11	488.75
80	Nov-01	80,237.26	845.15	481.37
81	Dec-01	79,574.14	838.19	474.06
82	Jan-02	78,911.02	831.24	466.83
83	Feb-02	78,247.90	824.28	459.67
84	Mar-02	77,584.79	817.33	452.60
85	Apr-02	76,921.67	810.37	445.60
86	May-02	76,258.55	803.41	438.68

Return Foregone if Collected Without Return on Over 17 Years
Trojan Net of Plant Classified as In-Service, Boardman Offset
Uses UE-88 Authorized COC

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)
Net Trojan After-Tax Balance		133,286.68

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
January 1996 -- September 2001:	13.34%
October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
87	Jun-02	75,595.43	796.46	431.83
88	Jul-02	74,932.32	789.50	425.06
89	Aug-02	74,269.20	782.55	418.36
90	Sep-02	73,606.08	775.59	411.73
91	Oct-02	72,942.96	768.64	405.18
92	Nov-02	72,279.84	761.68	398.70
93	Dec-02	71,616.73	754.72	392.29
94	Jan-03	70,953.61	747.77	385.95
95	Feb-03	70,290.49	740.81	379.68
96	Mar-03	69,627.37	733.86	373.47
97	Apr-03	68,964.25	726.90	367.34
98	May-03	68,301.14	719.94	361.27
99	Jun-03	67,638.02	712.99	355.27
100	Jul-03	66,974.90	706.03	349.34
101	Aug-03	66,311.78	699.08	343.47
102	Sep-03	65,648.67	692.12	337.67
103	Oct-03	64,985.55	685.16	331.94
104	Nov-03	64,322.43	678.21	326.26
105	Dec-03	63,659.31	671.25	320.65
106	Jan-04	62,996.19	664.30	315.10
107	Feb-04	62,333.08	657.34	309.62
108	Mar-04	61,669.96	650.38	304.19
109	Apr-04	61,006.84	643.43	298.83
110	May-04	60,343.72	636.47	293.53
111	Jun-04	59,680.61	629.52	288.28
112	Jul-04	59,017.49	622.56	283.10
113	Aug-04	58,354.37	615.60	277.97
114	Sep-04	57,691.25	608.65	272.91
115	Oct-04	57,028.13	601.69	267.89
116	Nov-04	56,365.02	594.74	262.94
117	Dec-04	55,701.90	587.78	258.04
118	Jan-05	55,038.78	580.82	253.20
119	Feb-05	54,375.66	573.87	248.42
120	Mar-05	53,712.54	566.91	243.68
121	Apr-05	53,049.43	559.96	239.01
122	May-05	52,386.31	553.00	234.38
123	Jun-05	51,723.19	546.04	229.81
124	Jul-05	51,060.07	539.09	225.29
125	Aug-05	50,396.96	532.13	220.83
126	Sep-05	49,733.84	525.18	216.41
127	Oct-05	49,070.72	518.22	212.05
128	Nov-05	48,407.60	511.26	207.74
129	Dec-05	47,744.48	504.31	203.47
130	Jan-06	47,081.37	497.35	199.26

Return Foregone if Collected Without Return on Over 17 Years
Trojan Net of Plant Classified as In-Service, Boardman Offset
Uses UE-88 Authorized COC

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)
Net Trojan After-Tax Balance		133,286.68

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
January 1996 -- September 2001:	13.34%
October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
131	Feb-06	46,418.25	490.40	195.09
132	Mar-06	45,755.13	483.44	190.98
133	Apr-06	45,092.01	476.48	186.91
134	May-06	44,428.89	469.53	182.89
135	Jun-06	43,765.78	462.57	178.92
136	Jul-06	43,102.66	455.62	174.99
137	Aug-06	42,439.54	448.66	171.11
138	Sep-06	41,776.42	441.70	167.28
139	Oct-06	41,113.31	434.75	163.49
140	Nov-06	40,450.19	427.79	159.75
141	Dec-06	39,787.07	420.84	156.05
142	Jan-07	39,123.95	413.88	152.39
143	Feb-07	38,460.83	406.92	148.78
144	Mar-07	37,797.72	399.97	145.21
145	Apr-07	37,134.60	393.01	141.69
146	May-07	36,471.48	386.06	138.20
147	Jun-07	35,808.36	379.10	134.76
148	Jul-07	35,145.25	372.14	131.36
149	Aug-07	34,482.13	365.19	128.00
150	Sep-07	33,819.01	358.23	124.68
151	Oct-07	33,155.89	351.28	121.40
152	Nov-07	32,492.77	344.32	118.17
153	Dec-07	31,829.66	337.36	114.97
154	Jan-08	31,166.54	330.41	111.81
155	Feb-08	30,503.42	323.45	108.69
156	Mar-08	29,840.30	316.50	105.60
157	Apr-08	29,177.18	309.54	102.56
158	May-08	28,514.07	302.58	99.55
159	Jun-08	27,850.95	295.63	96.58
160	Jul-08	27,187.83	288.67	93.65
161	Aug-08	26,524.71	281.72	90.75
162	Sep-08	25,861.60	274.76	87.89
163	Oct-08	25,198.48	267.80	85.06
164	Nov-08	24,535.36	260.85	82.27
165	Dec-08	23,872.24	253.89	79.52
166	Jan-09	23,209.12	246.94	76.80
167	Feb-09	22,546.01	239.98	74.11
168	Mar-09	21,882.89	233.03	71.46
169	Apr-09	21,219.77	226.07	68.84
170	May-09	20,556.65	219.11	66.25
171	Jun-09	19,893.54	212.16	63.70
172	Jul-09	19,230.42	205.20	61.18
173	Aug-09	18,567.30	198.25	58.69
174	Sep-09	17,904.18	191.29	56.23

Return Foregone if Collected Without Return on Over 17 Years
Trojan Net of Plant Classified as In-Service, Boardman Offset
Uses UE-88 Authorized COC

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)
Net Trojan After-Tax Balance		133,286.68

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
January 1996 -- September 2001:	13.34%
October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
175	Oct-09	17,241.06	184.33	53.81
176	Nov-09	16,577.95	177.38	51.41
177	Dec-09	15,914.83	170.42	49.05
178	Jan-10	15,251.71	163.47	46.72
179	Feb-10	14,588.59	156.51	44.42
180	Mar-10	13,925.47	149.55	42.15
181	Apr-10	13,262.36	142.60	39.90
182	May-10	12,599.24	135.64	37.69
183	Jun-10	11,936.12	128.69	35.51
184	Jul-10	11,273.00	121.73	33.35
185	Aug-10	10,609.89	114.77	31.23
186	Sep-10	9,946.77	107.82	29.13
187	Oct-10	9,283.65	100.86	27.06
188	Nov-10	8,620.53	93.91	25.02
189	Dec-10	7,957.41	86.95	23.00
190	Jan-11	7,294.30	79.99	21.01
191	Feb-11	6,631.18	73.04	19.05
192	Mar-11	5,968.06	66.08	17.12
193	Apr-11	5,304.94	59.13	15.21
194	May-11	4,641.82	52.17	13.32
195	Jun-11	3,978.71	45.21	11.47
196	Jul-11	3,315.59	38.26	9.63
197	Aug-11	2,652.47	31.30	7.83
198	Sep-11	1,989.35	24.35	6.04
199	Oct-11	1,326.24	17.39	4.29
200	Nov-11	663.12	10.43	2.55
201	Dec-11	0.00	3.48	0.85
	Sum:		140,409.54	91,937.20

Return Foregone if Collection Without Return on Over 17 Years
Trojan Net of Classified as In-Service Portion, Boardman Offset
Uses UE-88 Authorized COC + 150 BP ROE

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44		
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)		
04/01/95 Deferred ITC Balance:	(9,756.00)		
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44	
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)	per Order 95-1216
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)	
Net Trojan After-Tax Balance		133,286.68	

Pre-Tax Overall Rates of Return:		IF ROE UP 150 BASIS PTS
April 1995 -- December 1995:	13.22%	14.34%
January 1996 -- September 2001:	13.34%	14.49%
October 2001 -- December 2011:	13.34%	14.49%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
	Mar-95	133,286.68		
1	Apr-95	132,623.57	1,493.07	1,482.61
2	May-95	131,960.45	1,485.63	1,464.87
3	Jun-95	131,297.33	1,478.18	1,447.31
4	Jul-95	130,634.21	1,470.73	1,429.92
5	Aug-95	129,971.10	1,463.29	1,412.70
6	Sep-95	129,307.98	1,455.84	1,395.66
7	Oct-95	128,644.86	1,448.39	1,378.79
8	Nov-95	127,981.74	1,440.95	1,362.08
9	Dec-95	127,318.62	1,433.50	1,345.54
10	Jan-96	126,655.51	1,440.30	1,342.44
11	Feb-96	125,992.39	1,432.78	1,326.07
12	Mar-96	125,329.27	1,425.26	1,309.86
13	Apr-96	124,666.15	1,417.74	1,293.81
14	May-96	124,003.04	1,410.22	1,277.93
15	Jun-96	123,339.92	1,402.70	1,262.20
16	Jul-96	122,676.80	1,395.18	1,246.63
17	Aug-96	122,013.68	1,387.65	1,231.21
18	Sep-96	121,350.56	1,380.13	1,215.96
19	Oct-96	120,687.45	1,372.61	1,200.85
20	Nov-96	120,024.33	1,365.09	1,185.90
21	Dec-96	119,361.21	1,357.57	1,171.09
22	Jan-97	118,698.09	1,350.05	1,156.44
23	Feb-97	118,034.97	1,342.53	1,141.93
24	Mar-97	117,371.86	1,335.01	1,127.58
25	Apr-97	116,708.74	1,327.49	1,113.36
26	May-97	116,045.62	1,319.96	1,099.29
27	Jun-97	115,382.50	1,312.44	1,085.36
28	Jul-97	114,719.39	1,304.92	1,071.58
29	Aug-97	114,056.27	1,297.40	1,057.93
30	Sep-97	113,393.15	1,289.88	1,044.42
31	Oct-97	112,730.03	1,282.36	1,031.05
32	Nov-97	112,066.91	1,274.84	1,017.82
33	Dec-97	111,403.80	1,267.32	1,004.72
34	Jan-98	110,740.68	1,259.79	991.76
35	Feb-98	110,077.56	1,252.27	978.92
36	Mar-98	109,414.44	1,244.75	966.22
37	Apr-98	108,751.32	1,237.23	953.65
38	May-98	108,088.21	1,229.71	941.21
39	Jun-98	107,425.09	1,222.19	928.89
40	Jul-98	106,761.97	1,214.67	916.70
41	Aug-98	106,098.85	1,207.15	904.64
42	Sep-98	105,435.74	1,199.63	892.70
43	Oct-98	104,772.62	1,192.10	880.88
44	Nov-98	104,109.50	1,184.58	869.19
45	Dec-98	103,446.38	1,177.06	857.61
46	Jan-99	102,783.26	1,169.54	846.16
47	Feb-99	102,120.15	1,162.02	834.82

Return Foregone if Collection Without Return on Over 17 Years
Trojan Net of Classified as In-Service Portion, Boardman Offset
Uses UE-88 Authorized COC + 150 BP ROE

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44		
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)		
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04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44	
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)	per Order 95-1216
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)	
Net Trojan After-Tax Balance		133,286.68	

Pre-Tax Overall Rates of Return:		IF ROE UP 150 BASIS PTS
April 1995 -- December 1995:	13.22%	14.34%
January 1996 -- September 2001:	13.34%	14.49%
October 2001 -- December 2011:	13.34%	14.49%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
48	Mar-99	101,457.03	1,154.50	823.60
49	Apr-99	100,793.91	1,146.98	812.50
50	May-99	100,130.79	1,139.46	801.51
51	Jun-99	99,467.68	1,131.93	790.64
52	Jul-99	98,804.56	1,124.41	779.88
53	Aug-99	98,141.44	1,116.89	769.23
54	Sep-99	97,478.32	1,109.37	758.70
55	Oct-99	96,815.20	1,101.85	748.27
56	Nov-99	96,152.09	1,094.33	737.95
57	Dec-99	95,488.97	1,086.81	727.74
58	Jan-00	94,825.85	1,079.29	717.64
59	Feb-00	94,162.73	1,071.77	707.64
60	Mar-00	93,499.61	1,064.24	697.75
61	Apr-00	92,836.50	1,056.72	687.96
62	May-00	92,173.38	1,049.20	678.27
63	Jun-00	91,510.26	1,041.68	668.69
64	Jul-00	90,847.14	1,034.16	659.21
65	Aug-00	90,184.03	1,026.64	649.82
66	Sep-00	89,520.91	1,019.12	640.54
67	Oct-00	88,857.79	1,011.60	631.35
68	Nov-00	88,194.67	1,004.08	622.27
69	Dec-00	87,531.55	996.55	613.27
70	Jan-01	86,868.44	989.03	604.38
71	Feb-01	86,205.32	981.51	595.58
72	Mar-01	85,542.20	973.99	586.87
73	Apr-01	84,879.08	966.47	578.26
74	May-01	84,215.97	958.95	569.73
75	Jun-01	83,552.85	951.43	561.30
76	Jul-01	82,889.73	943.91	552.96
77	Aug-01	82,226.61	936.38	544.71
78	Sep-01	81,563.49	928.86	536.54
79	Oct-01	80,900.38	921.34	528.47
80	Nov-01	80,237.26	913.82	520.48
81	Dec-01	79,574.14	906.30	512.58
82	Jan-02	78,911.02	898.78	504.76
83	Feb-02	78,247.90	891.26	497.02
84	Mar-02	77,584.79	883.74	489.37
85	Apr-02	76,921.67	876.22	481.81
86	May-02	76,258.55	868.69	474.32
87	Jun-02	75,595.43	861.17	466.92
88	Jul-02	74,932.32	853.65	459.60
89	Aug-02	74,269.20	846.13	452.35
90	Sep-02	73,606.08	838.61	445.19
91	Oct-02	72,942.96	831.09	438.10
92	Nov-02	72,279.84	823.57	431.09
93	Dec-02	71,616.73	816.05	424.16
94	Jan-03	70,953.61	808.52	417.31
95	Feb-03	70,290.49	801.00	410.53
96	Mar-03	69,627.37	793.48	403.82

Return Foregone if Collection Without Return on Over 17 Years
Trojan Net of Classified as In-Service Portion, Boardman Offset
Uses UE-88 Authorized COC + 150 BP ROE

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44		
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)		
04/01/95 Deferred ITC Balance:	(9,756.00)		
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44	
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)	per Order 95-1216
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)	
Net Trojan After-Tax Balance		133,286.68	

Pre-Tax Overall Rates of Return:		IF ROE UP 150 BASIS PTS
April 1995 -- December 1995:	13.22%	14.34%
January 1996 -- September 2001:	13.34%	14.49%
October 2001 -- December 2011:	13.34%	14.49%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
97	Apr-03	68,964.25	785.96	397.19
98	May-03	68,301.14	778.44	390.63
99	Jun-03	67,638.02	770.92	384.14
100	Jul-03	66,974.90	763.40	377.73
101	Aug-03	66,311.78	755.88	371.38
102	Sep-03	65,648.67	748.36	365.11
103	Oct-03	64,985.55	740.83	358.91
104	Nov-03	64,322.43	733.31	352.77
105	Dec-03	63,659.31	725.79	346.71
106	Jan-04	62,996.19	718.27	340.71
107	Feb-04	62,333.08	710.75	334.78
108	Mar-04	61,669.96	703.23	328.91
109	Apr-04	61,006.84	695.71	323.11
110	May-04	60,343.72	688.19	317.38
111	Jun-04	59,680.61	680.67	311.71
112	Jul-04	59,017.49	673.14	306.10
113	Aug-04	58,354.37	665.62	300.56
114	Sep-04	57,691.25	658.10	295.08
115	Oct-04	57,028.13	650.58	289.66
116	Nov-04	56,365.02	643.06	284.31
117	Dec-04	55,701.90	635.54	279.01
118	Jan-05	55,038.78	628.02	273.78
119	Feb-05	54,375.66	620.50	268.60
120	Mar-05	53,712.54	612.97	263.48
121	Apr-05	53,049.43	605.45	258.43
122	May-05	52,386.31	597.93	253.43
123	Jun-05	51,723.19	590.41	248.48
124	Jul-05	51,060.07	582.89	243.60
125	Aug-05	50,396.96	575.37	238.77
126	Sep-05	49,733.84	567.85	234.00
127	Oct-05	49,070.72	560.33	229.28
128	Nov-05	48,407.60	552.81	224.61
129	Dec-05	47,744.48	545.28	220.01
130	Jan-06	47,081.37	537.76	215.45
131	Feb-06	46,418.25	530.24	210.95
132	Mar-06	45,755.13	522.72	206.50
133	Apr-06	45,092.01	515.20	202.10
134	May-06	44,428.89	507.68	197.75
135	Jun-06	43,765.78	500.16	193.46
136	Jul-06	43,102.66	492.64	189.21
137	Aug-06	42,439.54	485.11	185.02
138	Sep-06	41,776.42	477.59	180.87
139	Oct-06	41,113.31	470.07	176.77
140	Nov-06	40,450.19	462.55	172.73
141	Dec-06	39,787.07	455.03	168.73
142	Jan-07	39,123.95	447.51	164.77
143	Feb-07	38,460.83	439.99	160.87
144	Mar-07	37,797.72	432.47	157.01
145	Apr-07	37,134.60	424.95	153.20

Return Foregone if Collection Without Return on Over 17 Years
Trojan Net of Classified as In-Service Portion, Boardman Offset
Uses UE-88 Authorized COC + 150 BP ROE

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44		
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04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44	
04/01/95 After-Tax Balance of Boardman Gain		(68,378.66)	per Order 95-1216
04/01/95 After-Tax Trojan Classified as In-Service Amount		(62,215.09)	
Net Trojan After-Tax Balance		133,286.68	

Pre-Tax Overall Rates of Return:		IF ROE UP 150 BASIS PTS
April 1995 -- December 1995:	13.22%	14.34%
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October 2001 -- December 2011:	13.34%	14.49%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
146	May-07	36,471.48	417.42	149.43
147	Jun-07	35,808.36	409.90	145.71
148	Jul-07	35,145.25	402.38	142.03
149	Aug-07	34,482.13	394.86	138.40
150	Sep-07	33,819.01	387.34	134.81
151	Oct-07	33,155.89	379.82	131.27
152	Nov-07	32,492.77	372.30	127.77
153	Dec-07	31,829.66	364.78	124.31
154	Jan-08	31,166.54	357.26	120.89
155	Feb-08	30,503.42	349.73	117.52
156	Mar-08	29,840.30	342.21	114.18
157	Apr-08	29,177.18	334.69	110.89
158	May-08	28,514.07	327.17	107.64
159	Jun-08	27,850.95	319.65	104.43
160	Jul-08	27,187.83	312.13	101.25
161	Aug-08	26,524.71	304.61	98.12
162	Sep-08	25,861.60	297.09	95.03
163	Oct-08	25,198.48	289.56	91.97
164	Nov-08	24,535.36	282.04	88.96
165	Dec-08	23,872.24	274.52	85.98
166	Jan-09	23,209.12	267.00	83.04
167	Feb-09	22,546.01	259.48	80.13
168	Mar-09	21,882.89	251.96	77.26
169	Apr-09	21,219.77	244.44	74.43
170	May-09	20,556.65	236.92	71.63
171	Jun-09	19,893.54	229.40	68.87
172	Jul-09	19,230.42	221.87	66.15
173	Aug-09	18,567.30	214.35	63.46
174	Sep-09	17,904.18	206.83	60.80
175	Oct-09	17,241.06	199.31	58.18
176	Nov-09	16,577.95	191.79	55.59
177	Dec-09	15,914.83	184.27	53.04
178	Jan-10	15,251.71	176.75	50.52
179	Feb-10	14,588.59	169.23	48.03
180	Mar-10	13,925.47	161.70	45.57
181	Apr-10	13,262.36	154.18	43.15
182	May-10	12,599.24	146.66	40.75
183	Jun-10	11,936.12	139.14	38.39
184	Jul-10	11,273.00	131.62	36.06
185	Aug-10	10,609.89	124.10	33.76
186	Sep-10	9,946.77	116.58	31.50
187	Oct-10	9,283.65	109.06	29.26
188	Nov-10	8,620.53	101.54	27.05
189	Dec-10	7,957.41	94.01	24.87
190	Jan-11	7,294.30	86.49	22.72
191	Feb-11	6,631.18	78.97	20.60
192	Mar-11	5,968.06	71.45	18.51
193	Apr-11	5,304.94	63.93	16.44
194	May-11	4,641.82	56.41	14.41

Return Foregone if Collection Without Return on Over 17 Years
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Starting Balance 04/01/95:

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Net Trojan After-Tax Balance		133,286.68	

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After-Tax Rate of Return from 1992 IRP:	8.81%	

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
195	Jun-11	3,978.71	48.89	12.40
196	Jul-11	3,315.59	41.37	10.42
197	Aug-11	2,652.47	33.85	8.46
198	Sep-11	1,989.35	26.32	6.54
199	Oct-11	1,326.24	18.80	4.64
200	Nov-11	663.12	11.28	2.76
201	Dec-11	0.00	3.76	0.91
	Sum:		151,799.64	99,389.46

Return Foregone if Collection Without Return on Over 17 Years
Trojan Balance per UE-88
Uses UE-88 Authorized COC

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After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
	Mar-95	263,880.44		
1	Apr-95	262,567.60	2,737.69	2,718.49
2	May-95	261,254.76	2,724.03	2,685.97
3	Jun-95	259,941.92	2,710.38	2,653.77
4	Jul-95	258,629.08	2,696.73	2,621.89
5	Aug-95	257,316.25	2,683.07	2,590.32
6	Sep-95	256,003.41	2,669.42	2,559.07
7	Oct-95	254,690.57	2,655.76	2,528.13
8	Nov-95	253,377.73	2,642.11	2,497.50
9	Dec-95	252,064.89	2,628.45	2,467.17
10	Jan-96	250,752.06	2,637.22	2,458.04
11	Feb-96	249,439.22	2,623.45	2,428.06
12	Mar-96	248,126.38	2,609.68	2,398.38
13	Apr-96	246,813.54	2,595.91	2,369.00
14	May-96	245,500.70	2,582.14	2,339.91
15	Jun-96	244,187.87	2,568.37	2,311.11
16	Jul-96	242,875.03	2,554.60	2,282.60
17	Aug-96	241,562.19	2,540.82	2,254.38
18	Sep-96	240,249.35	2,527.05	2,226.44
19	Oct-96	238,936.51	2,513.28	2,198.78
20	Nov-96	237,623.68	2,499.51	2,171.40
21	Dec-96	236,310.84	2,485.74	2,144.30
22	Jan-97	234,998.00	2,471.97	2,117.47
23	Feb-97	233,685.16	2,458.20	2,090.91
24	Mar-97	232,372.32	2,444.42	2,064.61
25	Apr-97	231,059.49	2,430.65	2,038.59
26	May-97	229,746.65	2,416.88	2,012.83
27	Jun-97	228,433.81	2,403.11	1,987.33
28	Jul-97	227,120.97	2,389.34	1,962.08
29	Aug-97	225,808.13	2,375.57	1,937.10
30	Sep-97	224,495.30	2,361.80	1,912.36
31	Oct-97	223,182.46	2,348.03	1,887.88
32	Nov-97	221,869.62	2,334.25	1,863.65
33	Dec-97	220,556.78	2,320.48	1,839.67
34	Jan-98	219,243.94	2,306.71	1,815.93
35	Feb-98	217,931.11	2,292.94	1,792.43
36	Mar-98	216,618.27	2,279.17	1,769.17
37	Apr-98	215,305.43	2,265.40	1,746.15
38	May-98	213,992.59	2,251.63	1,723.37
39	Jun-98	212,679.75	2,237.85	1,700.82
40	Jul-98	211,366.92	2,224.08	1,678.50
41	Aug-98	210,054.08	2,210.31	1,656.41
42	Sep-98	208,741.24	2,196.54	1,634.55
43	Oct-98	207,428.40	2,182.77	1,612.91
44	Nov-98	206,115.56	2,169.00	1,591.50
45	Dec-98	204,802.73	2,155.23	1,570.31

Return Foregone if Collection Without Return on Over 17 Years
Trojan Balance per UE-88
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Starting Balance 04/01/95:

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04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
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October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
46	Jan-99	203,489.89	2,141.45	1,549.33
47	Feb-99	202,177.05	2,127.68	1,528.58
48	Mar-99	200,864.21	2,113.91	1,508.04
49	Apr-99	199,551.37	2,100.14	1,487.71
50	May-99	198,238.54	2,086.37	1,467.59
51	Jun-99	196,925.70	2,072.60	1,447.68
52	Jul-99	195,612.86	2,058.83	1,427.98
53	Aug-99	194,300.02	2,045.05	1,408.48
54	Sep-99	192,987.18	2,031.28	1,389.19
55	Oct-99	191,674.35	2,017.51	1,370.09
56	Nov-99	190,361.51	2,003.74	1,351.20
57	Dec-99	189,048.67	1,989.97	1,332.51
58	Jan-00	187,735.83	1,976.20	1,314.01
59	Feb-00	186,422.99	1,962.43	1,295.70
60	Mar-00	185,110.16	1,948.65	1,277.59
61	Apr-00	183,797.32	1,934.88	1,259.66
62	May-00	182,484.48	1,921.11	1,241.93
63	Jun-00	181,171.64	1,907.34	1,224.38
64	Jul-00	179,858.80	1,893.57	1,207.02
65	Aug-00	178,545.97	1,879.80	1,189.84
66	Sep-00	177,233.13	1,866.03	1,172.84
67	Oct-00	175,920.29	1,852.25	1,156.02
68	Nov-00	174,607.45	1,838.48	1,139.38
69	Dec-00	173,294.61	1,824.71	1,122.92
70	Jan-01	171,981.78	1,810.94	1,106.63
71	Feb-01	170,668.94	1,797.17	1,090.52
72	Mar-01	169,356.10	1,783.40	1,074.57
73	Apr-01	168,043.26	1,769.63	1,058.80
74	May-01	166,730.42	1,755.85	1,043.19
75	Jun-01	165,417.59	1,742.08	1,027.75
76	Jul-01	164,104.75	1,728.31	1,012.48
77	Aug-01	162,791.91	1,714.54	997.37
78	Sep-01	161,479.07	1,700.77	982.42
79	Oct-01	160,166.23	1,687.00	967.63
80	Nov-01	158,853.40	1,673.23	953.01
81	Dec-01	157,540.56	1,659.45	938.54
82	Jan-02	156,227.72	1,645.68	924.22
83	Feb-02	154,914.88	1,631.91	910.06
84	Mar-02	153,602.04	1,618.14	896.05
85	Apr-02	152,289.21	1,604.37	882.20
86	May-02	150,976.37	1,590.60	868.49
87	Jun-02	149,663.53	1,576.83	854.94
88	Jul-02	148,350.69	1,563.05	841.53
89	Aug-02	147,037.85	1,549.28	828.27
90	Sep-02	145,725.02	1,535.51	815.15
91	Oct-02	144,412.18	1,521.74	802.17
92	Nov-02	143,099.34	1,507.97	789.34
93	Dec-02	141,786.50	1,494.20	776.65

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Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
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After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
94	Jan-03	140,473.66	1,480.43	764.10
95	Feb-03	139,160.83	1,466.65	751.68
96	Mar-03	137,847.99	1,452.88	739.40
97	Apr-03	136,535.15	1,439.11	727.26
98	May-03	135,222.31	1,425.34	715.25
99	Jun-03	133,909.47	1,411.57	703.37
100	Jul-03	132,596.64	1,397.80	691.63
101	Aug-03	131,283.80	1,384.03	680.01
102	Sep-03	129,970.96	1,370.26	668.52
103	Oct-03	128,658.12	1,356.48	657.16
104	Nov-03	127,345.28	1,342.71	645.93
105	Dec-03	126,032.45	1,328.94	634.82
106	Jan-04	124,719.61	1,315.17	623.84
107	Feb-04	123,406.77	1,301.40	612.98
108	Mar-04	122,093.93	1,287.63	602.24
109	Apr-04	120,781.09	1,273.86	591.62
110	May-04	119,468.26	1,260.08	581.12
111	Jun-04	118,155.42	1,246.31	570.74
112	Jul-04	116,842.58	1,232.54	560.48
113	Aug-04	115,529.74	1,218.77	550.33
114	Sep-04	114,216.90	1,205.00	540.30
115	Oct-04	112,904.07	1,191.23	530.38
116	Nov-04	111,591.23	1,177.46	520.57
117	Dec-04	110,278.39	1,163.68	510.87
118	Jan-05	108,965.55	1,149.91	501.29
119	Feb-05	107,652.71	1,136.14	491.81
120	Mar-05	106,339.88	1,122.37	482.45
121	Apr-05	105,027.04	1,108.60	473.18
122	May-05	103,714.20	1,094.83	464.03
123	Jun-05	102,401.36	1,081.06	454.98
124	Jul-05	101,088.52	1,067.28	446.04
125	Aug-05	99,775.69	1,053.51	437.19
126	Sep-05	98,462.85	1,039.74	428.45
127	Oct-05	97,150.01	1,025.97	419.81
128	Nov-05	95,837.17	1,012.20	411.27
129	Dec-05	94,524.33	998.43	402.83
130	Jan-06	93,211.50	984.66	394.49
131	Feb-06	91,898.66	970.88	386.25
132	Mar-06	90,585.82	957.11	378.10
133	Apr-06	89,272.98	943.34	370.05
134	May-06	87,960.15	929.57	362.09
135	Jun-06	86,647.31	915.80	354.22
136	Jul-06	85,334.47	902.03	346.45
137	Aug-06	84,021.63	888.26	338.77
138	Sep-06	82,708.79	874.48	331.18
139	Oct-06	81,395.96	860.71	323.68
140	Nov-06	80,083.12	846.94	316.26
141	Dec-06	78,770.28	833.17	308.94

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Uses UE-88 Authorized COC

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
January 1996 -- September 2001:	13.34%
October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
142	Jan-07	77,457.44	819.40	301.70
143	Feb-07	76,144.60	805.63	294.55
144	Mar-07	74,831.77	791.86	287.49
145	Apr-07	73,518.93	778.08	280.51
146	May-07	72,206.09	764.31	273.61
147	Jun-07	70,893.25	750.54	266.80
148	Jul-07	69,580.41	736.77	260.07
149	Aug-07	68,267.58	723.00	253.42
150	Sep-07	66,954.74	709.23	246.85
151	Oct-07	65,641.90	695.46	240.36
152	Nov-07	64,329.06	681.68	233.94
153	Dec-07	63,016.22	667.91	227.61
154	Jan-08	61,703.39	654.14	221.35
155	Feb-08	60,390.55	640.37	215.18
156	Mar-08	59,077.71	626.60	209.07
157	Apr-08	57,764.87	612.83	203.04
158	May-08	56,452.03	599.06	197.09
159	Jun-08	55,139.20	585.28	191.21
160	Jul-08	53,826.36	571.51	185.40
161	Aug-08	52,513.52	557.74	179.66
162	Sep-08	51,200.68	543.97	174.00
163	Oct-08	49,887.84	530.20	168.40
164	Nov-08	48,575.01	516.43	162.88
165	Dec-08	47,262.17	502.66	157.43
166	Jan-09	45,949.33	488.88	152.04
167	Feb-09	44,636.49	475.11	146.72
168	Mar-09	43,323.65	461.34	141.47
169	Apr-09	42,010.82	447.57	136.28
170	May-09	40,697.98	433.80	131.16
171	Jun-09	39,385.14	420.03	126.11
172	Jul-09	38,072.30	406.26	121.12
173	Aug-09	36,759.46	392.49	116.19
174	Sep-09	35,446.63	378.71	111.33
175	Oct-09	34,133.79	364.94	106.53
176	Nov-09	32,820.95	351.17	101.79
177	Dec-09	31,508.11	337.40	97.11
178	Jan-10	30,195.27	323.63	92.50
179	Feb-10	28,882.44	309.86	87.94
180	Mar-10	27,569.60	296.09	83.44
181	Apr-10	26,256.76	282.31	79.00
182	May-10	24,943.92	268.54	74.62
183	Jun-10	23,631.08	254.77	70.30
184	Jul-10	22,318.25	241.00	66.03
185	Aug-10	21,005.41	227.23	61.82
186	Sep-10	19,692.57	213.46	57.67
187	Oct-10	18,379.73	199.69	53.57
188	Nov-10	17,066.89	185.91	49.53
189	Dec-10	15,754.06	172.14	45.54

Return Foregone if Collection Without Return on Over 17 Years
Trojan Balance per UE-88
Uses UE-88 Authorized COC

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44

Pre-Tax Overall Rates of Return:

April 1995 -- December 1995:	13.22%
January 1996 -- September 2001:	13.34%
October 2001 -- December 2011:	13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
190	Jan-11	14,441.22	158.37	41.60
191	Feb-11	13,128.38	144.60	37.72
192	Mar-11	11,815.54	130.83	33.88
193	Apr-11	10,502.70	117.06	30.11
194	May-11	9,189.87	103.29	26.38
195	Jun-11	7,877.03	89.51	22.70
196	Jul-11	6,564.19	75.74	19.07
197	Aug-11	5,251.35	61.97	15.50
198	Sep-11	3,938.51	48.20	11.97
199	Oct-11	2,625.68	34.43	8.49
200	Nov-11	1,312.84	20.66	5.06
201	Dec-11	0.00	6.89	1.67
	Sum:		277,982.23	182,016.90

Return Foregone if Collection Without Return on Equity Over 17 Years
Trojan Balance per UE-88
Uses UE-88 Authorized ROE

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44

Pre-Tax Equity Portion Adjusted Rates of Return:			Pre-Tax Overall
April 1995 -- December 1995:	9.43%	3.79%	13.22%
January 1996 -- September 2001:	9.52%	3.82%	13.34%
October 2001 -- December 2011:	9.52%		13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Equity Portion Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
	Mar-95	263,880.44		
1	Apr-95	262,567.60	1,983.72	1,969.81
2	May-95	261,254.76	1,973.83	1,946.24
3	Jun-95	259,941.92	1,963.93	1,922.91
4	Jul-95	258,629.08	1,954.04	1,899.81
5	Aug-95	257,316.25	1,944.14	1,876.94
6	Sep-95	256,003.41	1,934.25	1,854.29
7	Oct-95	254,690.57	1,924.36	1,831.87
8	Nov-95	253,377.73	1,914.46	1,809.68
9	Dec-95	252,064.89	1,904.57	1,787.70
10	Jan-96	250,752.06	1,912.94	1,782.97
11	Feb-96	249,439.22	1,902.95	1,761.22
12	Mar-96	248,126.38	1,892.96	1,739.69
13	Apr-96	246,813.54	1,882.97	1,718.38
14	May-96	245,500.70	1,872.98	1,697.28
15	Jun-96	244,187.87	1,862.99	1,676.39
16	Jul-96	242,875.03	1,853.00	1,655.71
17	Aug-96	241,562.19	1,843.01	1,635.24
18	Sep-96	240,249.35	1,833.02	1,614.97
19	Oct-96	238,936.51	1,823.03	1,594.91
20	Nov-96	237,623.68	1,813.05	1,575.05
21	Dec-96	236,310.84	1,803.06	1,555.39
22	Jan-97	234,998.00	1,793.07	1,535.93
23	Feb-97	233,685.16	1,783.08	1,516.66
24	Mar-97	232,372.32	1,773.09	1,497.59
25	Apr-97	231,059.49	1,763.10	1,478.71
26	May-97	229,746.65	1,753.11	1,460.02
27	Jun-97	228,433.81	1,743.12	1,441.53
28	Jul-97	227,120.97	1,733.13	1,423.22
29	Aug-97	225,808.13	1,723.14	1,405.09
30	Sep-97	224,495.30	1,713.15	1,387.15
31	Oct-97	223,182.46	1,703.16	1,369.39
32	Nov-97	221,869.62	1,693.17	1,351.82
33	Dec-97	220,556.78	1,683.19	1,334.42
34	Jan-98	219,243.94	1,673.20	1,317.20
35	Feb-98	217,931.11	1,663.21	1,300.16
36	Mar-98	216,618.27	1,653.22	1,283.29
37	Apr-98	215,305.43	1,643.23	1,266.59
38	May-98	213,992.59	1,633.24	1,250.06
39	Jun-98	212,679.75	1,623.25	1,233.71
40	Jul-98	211,366.92	1,613.26	1,217.52
41	Aug-98	210,054.08	1,603.27	1,201.49
42	Sep-98	208,741.24	1,593.28	1,185.64
43	Oct-98	207,428.40	1,583.29	1,169.94
44	Nov-98	206,115.56	1,573.30	1,154.41
45	Dec-98	204,802.73	1,563.31	1,139.04

Return Foregone if Collection Without Return on Equity Over 17 Years
Trojan Balance per UE-88
Uses UE-88 Authorized ROE

Starting Balance 04/01/95:

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44

Pre-Tax Equity Portion Adjusted Rates of Return:			Pre-Tax Overall
April 1995 -- December 1995:	9.43%	3.79%	13.22%
January 1996 -- September 2001:	9.52%	3.82%	13.34%
October 2001 -- December 2011:	9.52%		13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Equity Portion Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
46	Jan-99	203,489.89	1,553.33	1,123.82
47	Feb-99	202,177.05	1,543.34	1,108.77
48	Mar-99	200,864.21	1,533.35	1,093.87
49	Apr-99	199,551.37	1,523.36	1,079.12
50	May-99	198,238.54	1,513.37	1,064.53
51	Jun-99	196,925.70	1,503.38	1,050.09
52	Jul-99	195,612.86	1,493.39	1,035.80
53	Aug-99	194,300.02	1,483.40	1,021.66
54	Sep-99	192,987.18	1,473.41	1,007.66
55	Oct-99	191,674.35	1,463.42	993.81
56	Nov-99	190,361.51	1,453.43	980.11
57	Dec-99	189,048.67	1,443.44	966.55
58	Jan-00	187,735.83	1,433.45	953.13
59	Feb-00	186,422.99	1,423.47	939.85
60	Mar-00	185,110.16	1,413.48	926.71
61	Apr-00	183,797.32	1,403.49	913.71
62	May-00	182,484.48	1,393.50	900.85
63	Jun-00	181,171.64	1,383.51	888.12
64	Jul-00	179,858.80	1,373.52	875.52
65	Aug-00	178,545.97	1,363.53	863.06
66	Sep-00	177,233.13	1,353.54	850.73
67	Oct-00	175,920.29	1,343.55	838.53
68	Nov-00	174,607.45	1,333.56	826.46
69	Dec-00	173,294.61	1,323.57	814.52
70	Jan-01	171,981.78	1,313.58	802.71
71	Feb-01	170,668.94	1,303.59	791.02
72	Mar-01	169,356.10	1,293.61	779.45
73	Apr-01	168,043.26	1,283.62	768.01
74	May-01	166,730.42	1,273.63	756.69
75	Jun-01	165,417.59	1,263.64	745.49
76	Jul-01	164,104.75	1,253.65	734.41
77	Aug-01	162,791.91	1,243.66	723.45
78	Sep-01	161,479.07	1,233.67	712.61
79	Oct-01	160,166.23	1,223.68	701.88
80	Nov-01	158,853.40	1,213.69	691.27
81	Dec-01	157,540.56	1,203.70	680.78
82	Jan-02	156,227.72	1,193.71	670.39
83	Feb-02	154,914.88	1,183.72	660.12
84	Mar-02	153,602.04	1,173.73	649.96
85	Apr-02	152,289.21	1,163.75	639.91
86	May-02	150,976.37	1,153.76	629.97
87	Jun-02	149,663.53	1,143.77	620.14
88	Jul-02	148,350.69	1,133.78	610.41
89	Aug-02	147,037.85	1,123.79	600.79
90	Sep-02	145,725.02	1,113.80	591.28
91	Oct-02	144,412.18	1,103.81	581.87
92	Nov-02	143,099.34	1,093.82	572.56
93	Dec-02	141,786.50	1,083.83	563.35

Return Foregone if Collection Without Return on Equity Over 17 Years
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April 1995 -- December 1995:	9.43%	3.79%	13.22%
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October 2001 -- December 2011:	9.52%		13.34%

After-Tax Rate of Return from 1992 IRP: 8.81%

		Ending Balance	Equity Portion Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
94	Jan-03	140,473.66	1,073.84	554.24
95	Feb-03	139,160.83	1,063.85	545.24
96	Mar-03	137,847.99	1,053.86	536.33
97	Apr-03	136,535.15	1,043.87	527.52
98	May-03	135,222.31	1,033.89	518.81
99	Jun-03	133,909.47	1,023.90	510.20
100	Jul-03	132,596.64	1,013.91	501.68
101	Aug-03	131,283.80	1,003.92	493.25
102	Sep-03	129,970.96	993.93	484.92
103	Oct-03	128,658.12	983.94	476.68
104	Nov-03	127,345.28	973.95	468.53
105	Dec-03	126,032.45	963.96	460.48
106	Jan-04	124,719.61	953.97	452.51
107	Feb-04	123,406.77	943.98	444.63
108	Mar-04	122,093.93	933.99	436.84
109	Apr-04	120,781.09	924.00	429.14
110	May-04	119,468.26	914.01	421.52
111	Jun-04	118,155.42	904.03	413.99
112	Jul-04	116,842.58	894.04	406.55
113	Aug-04	115,529.74	884.05	399.19
114	Sep-04	114,216.90	874.06	391.91
115	Oct-04	112,904.07	864.07	384.71
116	Nov-04	111,591.23	854.08	377.60
117	Dec-04	110,278.39	844.09	370.57
118	Jan-05	108,965.55	834.10	363.62
119	Feb-05	107,652.71	824.11	356.74
120	Mar-05	106,339.88	814.12	349.95
121	Apr-05	105,027.04	804.13	343.23
122	May-05	103,714.20	794.14	336.59
123	Jun-05	102,401.36	784.15	330.02
124	Jul-05	101,088.52	774.17	323.54
125	Aug-05	99,775.69	764.18	317.12
126	Sep-05	98,462.85	754.19	310.78
127	Oct-05	97,150.01	744.20	304.52
128	Nov-05	95,837.17	734.21	298.32
129	Dec-05	94,524.33	724.22	292.20
130	Jan-06	93,211.50	714.23	286.15
131	Feb-06	91,898.66	704.24	280.17
132	Mar-06	90,585.82	694.25	274.26
133	Apr-06	89,272.98	684.26	268.42
134	May-06	87,960.15	674.27	262.64
135	Jun-06	86,647.31	664.28	256.94
136	Jul-06	85,334.47	654.29	251.30
137	Aug-06	84,021.63	644.31	245.73
138	Sep-06	82,708.79	634.32	240.22
139	Oct-06	81,395.96	624.33	234.78
140	Nov-06	80,083.12	614.34	229.41
141	Dec-06	78,770.28	604.35	224.09

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Starting Balance 04/01/95:

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142	Jan-07	77,457.44	594.36	218.84
143	Feb-07	76,144.60	584.37	213.66
144	Mar-07	74,831.77	574.38	208.53
145	Apr-07	73,518.93	564.39	203.47
146	May-07	72,206.09	554.40	198.47
147	Jun-07	70,893.25	544.41	193.52
148	Jul-07	69,580.41	534.42	188.64
149	Aug-07	68,267.58	524.43	183.82
150	Sep-07	66,954.74	514.45	179.05
151	Oct-07	65,641.90	504.46	174.34
152	Nov-07	64,329.06	494.47	169.69
153	Dec-07	63,016.22	484.48	165.10
154	Jan-08	61,703.39	474.49	160.56
155	Feb-08	60,390.55	464.50	156.08
156	Mar-08	59,077.71	454.51	151.65
157	Apr-08	57,764.87	444.52	147.28
158	May-08	56,452.03	434.53	142.96
159	Jun-08	55,139.20	424.54	138.69
160	Jul-08	53,826.36	414.55	134.48
161	Aug-08	52,513.52	404.56	130.32
162	Sep-08	51,200.68	394.57	126.21
163	Oct-08	49,887.84	384.59	122.15
164	Nov-08	48,575.01	374.60	118.15
165	Dec-08	47,262.17	364.61	114.19
166	Jan-09	45,949.33	354.62	110.28
167	Feb-09	44,636.49	344.63	106.42
168	Mar-09	43,323.65	334.64	102.62
169	Apr-09	42,010.82	324.65	98.85
170	May-09	40,697.98	314.66	95.14
171	Jun-09	39,385.14	304.67	91.47
172	Jul-09	38,072.30	294.68	87.86
173	Aug-09	36,759.46	284.69	84.28
174	Sep-09	35,446.63	274.70	80.75
175	Oct-09	34,133.79	264.71	77.27
176	Nov-09	32,820.95	254.73	73.84
177	Dec-09	31,508.11	244.74	70.44
178	Jan-10	30,195.27	234.75	67.09
179	Feb-10	28,882.44	224.76	63.79
180	Mar-10	27,569.60	214.77	60.53
181	Apr-10	26,256.76	204.78	57.31
182	May-10	24,943.92	194.79	54.13
183	Jun-10	23,631.08	184.80	50.99
184	Jul-10	22,318.25	174.81	47.90
185	Aug-10	21,005.41	164.82	44.84
186	Sep-10	19,692.57	154.83	41.83
187	Oct-10	18,379.73	144.84	38.86
188	Nov-10	17,066.89	134.85	35.92
189	Dec-10	15,754.06	124.87	33.03

Return Foregone if Collection Without Return on Equity Over 17 Years
Trojan Balance per UE-88
Uses UE-88 Authorized ROE

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October 2001 -- December 2011:	9.52%		13.34%
After-Tax Rate of Return from 1992 IRP:	8.81%		

		Ending Balance	Equity Portion Return on Average Balance	Net Present Value of Return on Average Balance (At 1992 IRP After-Tax Discount Rate)
190	Jan-11	14,441.22	114.88	30.17
191	Feb-11	13,128.38	104.89	27.36
192	Mar-11	11,815.54	94.90	24.58
193	Apr-11	10,502.70	84.91	21.84
194	May-11	9,189.87	74.92	19.13
195	Jun-11	7,877.03	64.93	16.47
196	Jul-11	6,564.19	54.94	13.83
197	Aug-11	5,251.35	44.95	11.24
198	Sep-11	3,938.51	34.96	8.68
199	Oct-11	2,625.68	24.97	6.16
200	Nov-11	1,312.84	14.98	3.67
201	Dec-11	0.00	4.99	1.21
	Sum:		201,618.76	132,009.98

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Apr-95	2,738	1,984	754
May-95	2,724	1,974	750
Jun-95	2,710	1,964	746
Jul-95	2,697	1,954	743
Aug-95	2,683	1,944	739
Sep-95	2,669	1,934	735
Oct-95	2,656	1,924	731
Nov-95	2,642	1,914	728
Dec-95	2,628	1,905	724
Jan-96	2,637	1,913	724
Feb-96	2,623	1,903	721
Mar-96	2,610	1,893	717
Apr-96	2,596	1,883	713
May-96	2,582	1,873	709
Jun-96	2,568	1,863	705
Jul-96	2,555	1,853	702
Aug-96	2,541	1,843	698
Sep-96	2,527	1,833	694
Oct-96	2,513	1,823	690
Nov-96	2,500	1,813	686
Dec-96	2,486	1,803	683
Jan-97	2,472	1,793	679
Feb-97	2,458	1,783	675
Mar-97	2,444	1,773	671
Apr-97	2,431	1,763	668
May-97	2,417	1,753	664
Jun-97	2,403	1,743	660
Jul-97	2,389	1,733	656
Aug-97	2,376	1,723	652
Sep-97	2,362	1,713	649
Oct-97	2,348	1,703	645
Nov-97	2,334	1,693	641
Dec-97	2,320	1,683	637
Jan-98	2,307	1,673	634
Feb-98	2,293	1,663	630
Mar-98	2,279	1,653	626
Apr-98	2,265	1,643	622
May-98	2,252	1,633	618
Jun-98	2,238	1,623	615
Jul-98	2,224	1,613	611
Aug-98	2,210	1,603	607
Sep-98	2,197	1,593	603
Oct-98	2,183	1,583	599
Nov-98	2,169	1,573	596
Dec-98	2,155	1,563	592
Jan-99	2,141	1,553	588
Feb-99	2,128	1,543	584
Mar-99	2,114	1,533	581
Apr-99	2,100	1,523	577
May-99	2,086	1,513	573
Jun-99	2,073	1,503	569
Jul-99	2,059	1,493	565

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Aug-99	2,045	1,483	562
Sep-99	2,031	1,473	558
Oct-99	2,018	1,463	554
Nov-99	2,004	1,453	550
Dec-99	1,990	1,443	547
Jan-00	1,976	1,433	543
Feb-00	1,962	1,423	539
Mar-00	1,949	1,413	535
Apr-00	1,935	1,403	531
May-00	1,921	1,393	528
Jun-00	1,907	1,384	524
Jul-00	1,894	1,374	520
Aug-00	1,880	1,364	516
Sep-00	1,866	1,354	512
Oct-00	1,852	1,344	509
Nov-00	1,838	1,334	505
Dec-00	1,825	1,324	501
Jan-01	1,811	1,314	497
Feb-01	1,797	1,304	494
Mar-01	1,783	1,294	490
Apr-01	1,770	1,284	486
May-01	1,756	1,274	482
Jun-01	1,742	1,264	478
Jul-01	1,728	1,254	475
Aug-01	1,715	1,244	471
Sep-01	1,701	1,234	467
Oct-01	1,687	1,224	463
Nov-01	1,673	1,214	460
Dec-01	1,659	1,204	456
Jan-02	1,646	1,194	452
Feb-02	1,632	1,184	448
Mar-02	1,618	1,174	444
Apr-02	1,604	1,164	441
May-02	1,591	1,154	437
Jun-02	1,577	1,144	433
Jul-02	1,563	1,134	429
Aug-02	1,549	1,124	425
Sep-02	1,536	1,114	422
Oct-02	1,522	1,104	418
Nov-02	1,508	1,094	414
Dec-02	1,494	1,084	410
Jan-03	1,480	1,074	407
Feb-03	1,467	1,064	403
Mar-03	1,453	1,054	399
Apr-03	1,439	1,044	395
May-03	1,425	1,034	391
Jun-03	1,412	1,024	388
Jul-03	1,398	1,014	384
Aug-03	1,384	1,004	380
Sep-03	1,370	994	376
Oct-03	1,356	984	373
Nov-03	1,343	974	369
Dec-03	1,329	964	365

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Jan-04	1,315	954	361
Feb-04	1,301	944	357
Mar-04	1,288	934	354
Apr-04	1,274	924	350
May-04	1,260	914	346
Jun-04	1,246	904	342
Jul-04	1,233	894	339
Aug-04	1,219	884	335
Sep-04	1,205	874	331
Oct-04	1,191	864	327
Nov-04	1,177	854	323
Dec-04	1,164	844	320
Jan-05	1,150	834	316
Feb-05	1,136	824	312
Mar-05	1,122	814	308
Apr-05	1,109	804	304
May-05	1,095	794	301
Jun-05	1,081	784	297
Jul-05	1,067	774	293
Aug-05	1,054	764	289
Sep-05	1,040	754	286
Oct-05	1,026	744	282
Nov-05	1,012	734	278
Dec-05	998	724	274
Jan-06	985	714	270
Feb-06	971	704	267
Mar-06	957	694	263
Apr-06	943	684	259
May-06	930	674	255
Jun-06	916	664	252
Jul-06	902	654	248
Aug-06	888	644	244
Sep-06	874	634	240
Oct-06	861	624	236
Nov-06	847	614	233
Dec-06	833	604	229
Jan-07	819	594	225
Feb-07	806	584	221
Mar-07	792	574	217
Apr-07	778	564	214
May-07	764	554	210
Jun-07	751	544	206
Jul-07	737	534	202
Aug-07	723	524	199
Sep-07	709	514	195
Oct-07	695	504	191
Nov-07	682	494	187
Dec-07	668	484	183
Jan-08	654	474	180
Feb-08	640	464	176
Mar-08	627	455	172
Apr-08	613	445	168
May-08	599	435	165

Implied Debt Only Return Over 17 Years
Calculated by Netting Total Return and Equity Only Return
Based on UE-88 Trojan Balance
Dollars in 000s

Period	Total Return	Equity Return	Debt Return
Jun-08	585	425	161
Jul-08	572	415	157
Aug-08	558	405	153
Sep-08	544	395	149
Oct-08	530	385	146
Nov-08	516	375	142
Dec-08	503	365	138
Jan-09	489	355	134
Feb-09	475	345	130
Mar-09	461	335	127
Apr-09	448	325	123
May-09	434	315	119
Jun-09	420	305	115
Jul-09	406	295	112
Aug-09	392	285	108
Sep-09	379	275	104
Oct-09	365	265	100
Nov-09	351	255	96
Dec-09	337	245	93
Jan-10	324	235	89
Feb-10	310	225	85
Mar-10	296	215	81
Apr-10	282	205	78
May-10	269	195	74
Jun-10	255	185	70
Jul-10	241	175	66
Aug-10	227	165	62
Sep-10	213	155	59
Oct-10	200	145	55
Nov-10	186	135	51
Dec-10	172	125	47
Jan-11	158	115	43
Feb-11	145	105	40
Mar-11	131	95	36
Apr-11	117	85	32
May-11	103	75	28
Jun-11	90	65	25
Jul-11	76	55	21
Aug-11	62	45	17
Sep-11	48	35	13
Oct-11	34	25	9
Nov-11	21	15	6
Dec-11	7	5	2
Sum	277,982	201,619	76,363

Calculation of Interest on Revenue Requirement Differential
1 Year Trojan Collection (with other changes) versus Authorized Revenue Requirements
Dollars in $000s

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	820.51	-	3.29	823.80
May		820.51	-	9.89	1,654.19
June		820.51	-	16.55	2,491.25
July		820.51	-	23.26	3,335.02
August		820.51	-	30.03	4,185.56
September		820.51	-	36.85	5,042.91
October		820.51	-	43.72	5,907.14
November		973.33	-	51.27	6,931.74
December		2,348.77	-	64.99	9,345.50
January	1996	2,348.77	-	85.16	11,779.44
February		2,348.77	-	104.86	14,233.07
March		2,348.77	-	124.72	16,706.56
April		(260.49)	-	134.18	16,580.24
May		(260.49)	-	133.16	16,452.91
June		(260.49)	-	132.13	16,324.55
July		(260.49)	-	131.09	16,195.14
August		(260.49)	-	130.04	16,064.69
September		(260.49)	-	128.99	15,933.18
October		(260.49)	-	127.92	15,800.61
November		(260.49)	-	126.85	15,666.97
December		107.19	-	127.25	15,901.41
January	1997	107.19	-	129.15	16,137.76
February		107.19	-	131.07	16,376.02
March		107.19	-	132.99	16,616.20
April		107.19	-	134.94	16,858.34
May		107.19	-	136.90	17,102.43
June		107.19	-	138.87	17,348.50
July		107.19	-	140.87	17,596.56
August		107.19	-	142.87	17,846.63
September		107.19	-	144.90	18,098.72
October		107.19	-	146.94	18,352.86
November		107.19	-	149.00	18,609.05
December		107.19	-	151.07	18,867.32
January	1998	107.19	-	153.16	19,127.67
February		107.19	-	155.27	19,390.13
March		107.19	-	157.39	19,654.72
April		107.19	-	159.53	19,921.44
May		107.19	-	161.69	20,190.33
June		107.19	-	163.87	20,461.39
July		107.19	-	166.06	20,734.65
August		107.19	-	168.28	21,010.12
September		107.19	-	170.51	21,287.83
October		107.19	-	172.75	21,567.77
November		107.19	-	175.02	21,849.98
December		107.19	-	177.31	22,134.49
January	1999	107.19	-	179.61	22,421.29
February		107.19	-	181.93	22,710.42
March		107.19	-	184.27	23,001.88
April		107.19	-	186.63	23,295.71
May		107.19	-	189.01	23,591.91

Calculation of Interest on Revenue Requirement Differential
1 Year Trojan Collection (with other changes) versus Authorized Revenue Requirements
Dollars in $000s

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
June		107.19	-	191.41	23,890.52
July		107.19	-	193.82	24,191.53
August		107.19	-	196.26	24,494.98
September		107.19	-	198.72	24,800.90
October		107.19	-	201.19	25,109.28
November		107.19	-	203.69	25,420.17
December		107.19	-	206.20	25,733.56
January	2000	107.19	-	208.74	26,049.50
February		107.19	-	211.30	26,367.99
March		107.19	-	213.88	26,689.07
April		107.19	-	216.48	27,012.74
May		107.19	-	219.10	27,339.04
June		107.19	-	221.74	27,667.97
July		107.19	-	224.40	27,999.56
August		107.19	-	227.08	28,333.84
September		107.19	-	229.79	28,670.82
	Totals	18,958.96	-	9,711.86	28,670.82
	1995 Amounts	9,065.65	-	279.85	9,345.50
	1996 Amounts	5,069.56	-	1,486.35	6,555.91
	1997 Amounts	1,286.33	-	1,679.57	2,965.90
	1998 Amounts	1,286.33	-	1,980.84	3,267.17
	1999 Amounts	1,286.33	-	2,312.74	3,599.07
	2000 Amounts	964.75	-	1,972.51	2,937.26
	Totals	18,958.96	-	9,711.86	28,670.82
					28,670.82

Calculation of Interest on Revenue Requirement Differential
17 Year Trojan Collection (with other changes) versus Authorized Revenue Requirements
Dollars in $000s

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	7.93	-	0.03	7.96
May		7.93	-	0.10	16.00
June		7.93	-	0.17	24.10
July		7.93	-	0.24	32.28
August		7.93	-	0.31	40.52
September		7.93	-	0.38	48.84
October		7.93	-	0.45	57.22
November		180.67	-	1.25	239.15
December		1,735.30	-	9.40	1,983.85
January	1996	1,735.30	-	24.46	3,743.61
February		1,735.30	-	39.56	5,518.47
March		1,735.30	-	54.79	7,308.56
April		2,281.06	-	72.48	9,662.10
May		2,281.06	-	92.67	12,035.84
June		2,281.06	-	113.04	14,429.94
July		2,281.06	-	133.58	16,844.58
August		2,281.06	-	154.29	19,279.94
September		2,281.06	-	175.18	21,736.18
October		2,281.06	-	196.26	24,213.51
November		2,281.06	-	217.51	26,712.08
December		718.44	-	232.24	27,662.76
January	1997	718.44	-	240.40	28,621.61
February		718.44	-	248.62	29,588.67
March		718.44	-	256.92	30,564.04
April		718.44	-	265.29	31,547.77
May		718.44	-	273.73	32,539.95
June		718.44	-	282.24	33,540.63
July		718.44	-	290.82	34,549.90
August		718.44	-	299.48	35,567.82
September		718.44	-	308.21	36,594.47
October		718.44	-	317.02	37,629.94
November		718.44	-	325.90	38,674.28
December		718.44	-	334.86	39,727.59
January	1998	718.44	-	343.90	40,789.93
February		718.44	-	353.01	41,861.39
March		718.44	-	362.20	42,942.03
April		718.44	-	371.48	44,031.96
May		718.44	-	380.83	45,131.23
June		718.44	-	390.26	46,239.93
July		718.44	-	399.77	47,358.15
August		718.44	-	409.36	48,485.95
September		718.44	-	419.04	49,623.44
October		718.44	-	428.79	50,770.67
November		718.44	-	438.64	51,927.76
December		718.44	-	448.56	53,094.76
January	1999	718.44	-	458.57	54,271.78
February		718.44	-	468.67	55,458.89
March		718.44	-	478.86	56,656.20
April		718.44	-	489.13	57,863.77
May		718.44	-	499.49	59,081.70

Calculation of Interest on Revenue Requirement Differential
17 Year Trojan Collection (with other changes) versus Authorized Revenue Requirements
Dollars in $000s

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
June		718.44	-	509.94	60,310.09
July		718.44	-	520.47	61,549.00
August		718.44	-	531.10	62,798.55
September		718.44	-	541.82	64,058.81
October		718.44	-	552.63	65,329.89
November		718.44	-	563.54	66,611.87
December		718.44	-	574.54	67,904.86
January	2000	718.44	-	585.63	69,208.93
February		718.44	-	596.82	70,524.20
March		718.44	-	608.10	71,850.74
April		718.44	-	619.48	73,188.66
May		718.44	-	630.96	74,538.07
June		718.44	-	642.53	75,899.04
July		718.44	-	654.21	77,271.70
August		718.44	-	665.98	78,656.12
September		718.44	-	677.86	80,052.43
	Totals	58,474.38	-	21,578.05	80,052.43
	1995 Amounts	1,971.52	-	12.33	1,983.85
	1996 Amounts	24,172.86	-	1,506.06	25,678.92
	1997 Amounts	8,621.33	-	3,443.49	12,064.82
	1998 Amounts	8,621.33	-	4,745.84	13,367.17
	1999 Amounts	8,621.33	-	6,188.76	14,810.09
	2000 Amounts	6,466.00	-	5,681.57	12,147.57
	Totals	58,474.38	-	21,578.05	80,052.43
					80,052.43

Return Forgone Under One-Year Recovery

04/01/95 Plant Balance (After Net-Benefit Test Disallowance; $000):	340,162.44	
04/01/95 Deferred Tax Balance (After Net-Benefit Test Disallowance):	(66,526.00)	
04/01/95 Deferred ITC Balance:	(9,756.00)	
04/01/95 After-Tax Balance (After Net-Benefit Test Disallowance):		263,880.44
Pre-Tax Cost of Capital Forgone Over One-Year Collection Period:	23,108.23	
Associated Deferred Tax Component:	(5,536.78)	
After-Tax Cost of Capital Forgone Over One-Year Collection Period:		17,571.46
Total 04/01/95 After-Tax Balance:		281,451.89

Revised Pre-Tax Balance:	363,270.67
Revised Deferred Tax Balance:	(72,062.78)
Revised Deferred ITC Balance:	(9,756.00)
Revised After-Tax Balance:	281,451.89

Order 95-322 Authorized Pre-Tax Cost of Capital for 04/01/95 - 12/31/95 Period:	13.22%
Order 95-322 Authorized Pre-Tax Cost of Capital for 01/01/96 - 04/01/96 Period:	13.32%

	Ending Balance	Cost of Average Balance
Mar-95	281,451.89	
Apr-95	257,997.57	2,805.30
May-95	234,543.25	2,561.36
Jun-95	211,088.92	2,317.42
Jul-95	187,634.60	2,073.48
Aug-95	164,180.27	1,829.54
Sep-95	140,725.95	1,585.60
Oct-95	117,271.62	1,341.66
Nov-95	93,817.30	1,097.73
Dec-95	70,362.97	853.79
Jan-96	46,908.65	614.21
Feb-96	23,454.32	368.52
Mar-96	(0.00)	122.84
Total		17,571.46

Summary of Net Benefit Test Result (UE-88, Order 95-322)
Dollars in Millions

1	Higher Cost of Continued Operation over 1996 phase-out	110.0
2	Higher Cost of 1996 phase-out over immediate shutdown	78.0
3	**Net Benefit of Closing Trojan per PGE 1992 IRP and Update**	**188.0**
	<u>Staff Proposed Adjustments to Net Benefit Test (See UE-88, Staff/105, Sparling/13)</u>	
	<u>Adjustments for Allowable Costs:</u>	
4	Steam Generator Replacement Costs	-183.1
5	45 MW Capacity Increase	2.2
6	Fixed O&M Costs @ 102.25 MM/yr ($92) escalated @ 1.5%	-482.7
7	Capacity Factor @ 69.6%	-318.4
8	Subtotal - Staff Proposed Adjustments for Allowable Costs	-982.0
	<u>Adjustments to Update with Current Information:</u>	
9	Transition Costs	78.7
10	Short-run Replacement Power Costs	115.7
11	Gas Prices	356.8
12	Capital Costs of gas-fired resources	202.1
13	Subtotal - Staff Proposed Updates for Current Information	753.3
14	Adjustments for 1995-2011 Study Period	12.5
15	Total Net Benefit ($92)	-28.3
16	PGE Share @ 67.5% ($92)	-19.1
17	**PGE Share @ 67.5% ($95) - Staff Net Benefit Result**	**-23.6**
	<u>Commission Adjustments to Staff Result (Order 95-322, pg. 52)</u>	
18	Janaury 1995-June 1996 uprate to 45 MW	-6.1
19	Increase Capactity Factor by .65 percent	-20.5
20	Decrease imputed Fixed O&M by $5.8 million	-51.8
21	Update to Nuclear Fuel Assumptions	25.7
22	Update to Staff's Carrying Costs	68.9
23	Update to Capital Costs of Replacement Resources	-16.0
24	Adjustment for Interaction	3.0
25	Total Commission Adjustments to Staff Net Benefit Test	3.2
26	**Commission Approved Net Benefit Result**	**-20.4**

Net Benefit Test Results for Scenarios
Dollars in millions

	Scenario 1	Description
Original After-Tax Net Benefit (UE-88)	(20.40)	Recover Trojan over 1 year with no "return on"
		Adjust net benefit test accordingly.
Pre-Tax Equivalent Based on PGE Writeoff	(26.83)	
Lost PV - Trojan over 1 Year with no "Return on"	23.11	
Adjusted Net Benefit Test Result	(3.72)	
Therefore, partial restoration of UE-88 net benefit test write-off.	23.11	Partial Restoration of UE-88 Net Benefit Write-off

	Scenario 2	Description
Original After-Tax Net Benefit (UE-88)	(20.40)	Recover Trojan over 1 year with no "return on"
		Add back recovery of steam generator under continued ops
Pre-Tax Equivalent Based on PGE Writeoff	(26.83)	Classify 80 MM of Trojan as Plant in Service
Lost PV - Net Trojan over 1 Year with no "Return on"	10.12	Reduce Remaining Trojan Balance by Boardman Credit
Recover Steam Generator in closure scenario	183.10	
Adjusted Net Benefit Result	166.40	
Therefore, full restoration of UE-88 net benefit test write-off	26.83	Restoration of UE-88 Net Benefit Write-off

	Scenario 3	Description
Original After-Tax Net Benefit (UE-88)	(20.40)	Recover Trojan over 17 years with no "return on"
		Add back recovery of steam generator under continued ops
Pre-Tax Equivalent Based on PGE Writeoff	(26.83)	Classify 80 MM of Trojan as Plant in Service
Lost PV - Net Trojan over 1 Year with no "Return on"	99.39	Reduce Remaining Trojan Balance by Boardman Credit
Recover Steam Generator in closure scenario	183.10	Share 20% of Net Benefit Test Savings
Adjusted Net Benefit Result	255.66	
Therefore, full restoration of UE-88 net benefit test	26.83	Restoration of UE-88 Net Benefit Write-off
write-off and 20% Share of Savings ($256 MM)	51.13	PGE Share of Savings at 20%

Other Net-Benefit Test Results
Support for Various Figures in Lesh Testimony

Pre-Tax Equivalent Based on PGE Writeoff	(26.83)	Restoration of UE-88 Net Benefit Write-off
Economic Value of No Return On Trojan Over 17 Years	182.02	NPV of Return Foregone Over 17 Year Period
Adjusted Net Benefit Result	155.19	

Pre-Tax Equivalent Based on PGE Writeoff	(26.83)	Restoration of UE-88 Net Benefit Write-off
Recover Steam Generator in closure scenario	183.10	Share 20% of Net Benefit Test Savings
Lost PV - Trojan over 1 Year with no "Return on"	23.11	Partial Restoration of UE-88 Net Benefit Write-off
Adjusted Net Benefit Result	179.38	

Pre-Tax Equivalent Based on PGE Writeoff	(26.83)	Restoration of UE-88 Net Benefit Write-off
Economic Value of No Return On Trojan Over 17 Years	182.02	NPV of Return Foregone Over 17 Year Period
Recover Steam Generator in closure scenario	183.10	Share 20% of Net Benefit Test Savings
Adjusted Net Benefit Result	338.29	

Track Authorized Revenue Requirement Versus 1 Year Collection
Add back UE-88 net benefit write-off for PV impact of 1 yr Trojan w/o Return on
$000s

UE-88 Write-off Restored 23,108

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	23,120		91.61	23,212.02
May		23,120		275.57	46,607.99
June		23,120		460.98	70,189.38
July		23,120		647.87	93,957.65
August		23,120		836.23	117,914.29
September		23,120		1,026.09	142,060.79
October		23,120		1,217.45	166,398.64
November		23,120		1,410.32	190,929.37
December		23,120		1,604.73	215,654.50
January	1996	25,782		1,828.36	243,265.04
February		25,782		2,049.25	271,096.47
March		25,782		2,271.90	299,150.55
April		(4,490)		2,375.24	297,035.44
May		(4,490)		2,358.32	294,903.42
June		(4,490)		2,341.27	292,754.35
July		(4,490)		2,324.07	290,588.08
August		(4,490)		2,306.74	288,404.48
September		(4,490)		2,289.27	286,203.40
October		(4,490)		2,271.67	283,984.73
November		(4,490)		2,253.92	281,748.31
December		(4,490)		2,236.03	279,494.00
January	1997	(4,124)		2,219.46	277,589.57
February		(4,124)		2,204.22	275,669.90
March		(4,124)		2,188.86	273,734.88
April		(4,124)		2,173.38	271,784.37
May		(4,124)		2,157.78	269,818.26
June		(4,124)		2,142.05	267,836.43
July		(4,124)		2,126.20	265,838.74
August		(4,124)		2,110.21	263,825.06
September		(4,124)		2,094.10	261,795.27
October		(4,124)		2,077.87	259,749.26
November		(4,124)		2,061.50	257,686.87
December		(4,124)		2,045.00	255,607.98
January	1998	(3,858)		2,029.43	253,779.82
February		(3,858)		2,014.81	251,937.04
March		(3,858)		2,000.07	250,079.52
April		(3,858)		1,985.21	248,207.14
May		(3,858)		1,970.23	246,319.78
June		(3,858)		1,955.13	244,417.31
July		(3,858)		1,939.91	242,499.63
August		(3,858)		1,924.57	240,566.61
September		(3,858)		1,909.10	238,618.12
October		(3,858)		1,893.51	236,654.04
November		(3,858)		1,877.80	234,674.25
December		(3,858)		1,861.96	232,678.61
January	1999	(3,971)		1,845.54	230,552.93
February		(3,971)		1,828.54	228,410.24
March		(3,971)		1,811.40	226,250.41
April		(3,971)		1,794.12	224,073.31
May		(3,971)		1,776.70	221,878.78
June		(3,971)		1,759.15	219,666.70
July		(3,971)		1,741.45	217,436.93
August		(3,971)		1,723.61	215,189.31
September		(3,971)		1,705.63	212,923.72
October		(3,971)		1,687.50	210,639.99
November		(3,971)		1,669.24	208,338.00

Track Authorized Revenue Requirement Versus 1 Year Collection
Add back UE-88 net benefit write-off for PV impact of 1 yr Trojan w/o Return on
$000s

UE-88 Write-off Restored 23,108

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
December		(3,971)		1,650.82	206,017.60
January	2000	(4,056)		1,631.92	203,593.82
February		(4,056)		1,612.53	201,150.65
March		(4,056)		1,592.98	198,687.93
April		(4,056)		1,573.28	196,205.51
May		(4,056)		1,553.42	193,703.23
June		(4,056)		1,533.40	191,180.93
July		(4,056)		1,513.22	188,638.45
August		(4,056)		1,492.88	186,075.63
September		(4,056)		1,472.38	183,492.31
	Totals	65,083.35	-	118,408.96	183,492.31
	1995 Amounts	208,083.65	-	7,570.85	215,654.50
	1996 Amounts	36,933.45	-	26,906.04	63,839.49
	1997 Amounts	(49,486.64)	-	25,600.63	(23,886.01)
	1998 Amounts	(46,291.10)	-	23,361.73	(22,929.37)
	1999 Amounts	(47,654.72)	-	20,993.70	(26,661.02)
	2000 Amounts	(36,501.30)	-	13,976.01	(22,525.29)
	Totals	65,083.35	-	118,408.96	183,492.31
					183,492.31
			Int Accrued thru 9/00	118,408.96	

Description: Collect Trojan over 1 year with no return on, add back write-off,
acheive intergenerational equity by reducing Trojan balance with the entirety of the Boardman gain, set up new regulatory asset to defer portion of 1st year collection of NVPC. Collect regulatory assets over 17 years through 2011.

Trojan Balance @4/1/1995	340.16
Boardman Gain Balance @ 4/1/1995	(111.15)
1yr collection PV loss	23.11
New Trojan Balance @ 4/1/1995	252.12
Trojan -- Per Rate Orders (4/1/95 - 9/30/00)	298.19
UE 88 Power Costs - 1st year	309.30

Reg Asset Balances @ 4/1/1995 (Items offset by Boardman Gain):

Trojan Pwr Cost Deferrals	48.46	All per Order 95-2116
AMAX	15.84	
SAVE	27.88	
Total	92.18	Collected through 2011
UE-88 Power Cost Forecast	309.30	Avg per Order 95-322
New Reg Asset - Power Costs	247.98	Collected through 2011
1st Yr Collection of Power Costs	61.32	
Total Reg Assets @ 4/1/1995	340.16	

Trojan Revenue Requirements
Dollars in 000s

	(9 Mos) 1995	1996	1997	1998	1999	(9 Mos) 2000	Total
Return On	25,229.73	28,321.18	25,789.47	23,730.17	21,135.53	14,304.17	138,510.26
Return Of	39,139.29	25,562.92	23,697.17	22,560.93	26,519.19	22,197.13	159,676.63
Total	64,369.02	53,884.11	49,486.64	46,291.10	47,654.72	36,501.30	298,186.89

Collect Power Cost Deferral and Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	112.85	(3.28)	0.43	110.00
May		20.66	(3.28)	0.94	128.33
June		20.66	(3.28)	1.09	146.81
July		20.66	(3.28)	1.23	165.43
August		20.66	(3.28)	1.38	184.20
September		20.66	(3.28)	1.53	203.12
October		20.66	(3.28)	1.68	222.19
November		20.66	(3.28)	1.83	241.41
December		20.66	(3.28)	1.98	260.78
January	1996	20.66	(3.28)	2.16	280.33
February		20.66	(3.28)	2.31	300.03
March		20.66	(3.28)	2.47	319.89
April			(3.28)	2.55	319.16
May			(3.28)	2.54	318.43
June			(3.28)	2.53	317.68
July			(3.28)	2.53	316.94
August			(3.28)	2.52	316.18
September			(3.28)	2.52	315.43
October			(3.28)	2.51	314.66
November			(3.28)	2.50	313.89
December			(3.28)	2.50	313.11
January	1997		(3.28)	2.49	312.33
February			(3.28)	2.48	311.53
March			(3.28)	2.48	310.74
April			(3.28)	2.47	309.93
May			(3.28)	2.47	309.13
June			(3.28)	2.46	308.31
July			(3.28)	2.45	307.49
August			(3.28)	2.45	306.66
September			(3.28)	2.44	305.83
October			(3.28)	2.43	304.98
November			(3.28)	2.43	304.14
December			(3.28)	2.42	303.28
January	1998		(3.28)	2.41	302.42
February			(3.28)	2.41	301.55
March			(3.28)	2.40	300.68
April			(3.28)	2.39	299.79
May			(3.28)	2.38	298.89
June			(3.28)	2.38	298.00
July			(3.28)	2.37	297.09
August			(3.28)	2.36	296.18
September			(3.28)	2.36	295.26
October			(3.28)	2.35	294.34
November			(3.28)	2.34	293.40
December			(3.28)	2.33	292.46
January	1999		(3.28)	2.33	291.51
February			(3.28)	2.32	290.56
March			(3.28)	2.31	289.59
April			(3.28)	2.30	288.62
May			(3.28)	2.30	287.64

Collect Power Cost Deferral and Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance	
June			(3.28)	2.29	286.66	
July			(3.28)	2.28	285.66	
August			(3.28)	2.27	284.66	
September			(3.28)	2.26	283.64	
October			(3.28)	2.26	282.63	
November			(3.28)	2.25	281.60	
December			(3.28)	2.24	280.57	
January	2000		(3.28)	2.23	279.52	
February			(3.28)	2.22	278.47	
March			(3.28)	2.21	277.40	
April			(3.28)	2.21	276.34	
May			(3.28)	2.20	275.26	
June			(3.28)	2.19	274.18	
July			(3.28)	2.18	273.08	Total
August			(3.28)	2.17	271.97	Payments
September			(3.28)	2.16	270.86	(216.162)
October			(3.28)	2.15	269.73	
November			(3.28)	2.14	268.60	
December			(3.28)	2.14	267.46	
January	2001		(3.28)	2.13	266.32	
February			(3.28)	2.12	265.16	
March			(3.28)	2.11	264.00	
April			(3.28)	2.10	262.82	
May			(3.28)	2.09	261.64	
June			(3.28)	2.08	260.44	
July			(3.28)	2.07	259.24	
August			(3.28)	2.06	258.02	
September			(3.28)	2.05	256.80	
October			(3.28)	2.04	255.56	
November			(3.28)	2.03	254.32	
December			(3.28)	2.02	253.06	
January	2002		(3.28)	2.01	251.80	
February			(3.28)	2.00	250.52	
March			(3.28)	1.99	249.24	
April			(3.28)	1.98	247.94	
May			(3.28)	1.97	246.64	
June			(3.28)	1.96	245.32	
July			(3.28)	1.95	244.00	
August			(3.28)	1.94	242.66	
September			(3.28)	1.93	241.32	
October			(3.28)	1.92	239.96	
November			(3.28)	1.91	238.59	
December			(3.28)	1.90	237.22	
January	2003		(3.28)	1.88	235.82	
February			(3.28)	1.87	234.42	
March			(3.28)	1.86	233.00	
April			(3.28)	1.85	231.58	
May			(3.28)	1.84	230.14	
June			(3.28)	1.83	228.70	
July			(3.28)	1.82	227.24	
August			(3.28)	1.80	225.77	
September			(3.28)	1.79	224.28	

Collect Power Cost Deferral and Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
October			(3.28)	1.78	222.79
November			(3.28)	1.77	221.28
December			(3.28)	1.76	219.77
January	2004		(3.28)	1.74	218.23
February			(3.28)	1.73	216.69
March			(3.28)	1.72	215.13
April			(3.28)	1.71	213.57
May			(3.28)	1.70	211.99
June			(3.28)	1.68	210.40
July			(3.28)	1.67	208.79
August			(3.28)	1.66	207.18
September			(3.28)	1.64	205.54
October			(3.28)	1.63	203.90
November			(3.28)	1.62	202.24
December			(3.28)	1.60	200.57
January	2005		(3.28)	1.59	198.88
February			(3.28)	1.58	197.18
March			(3.28)	1.56	195.47
April			(3.28)	1.55	193.74
May			(3.28)	1.54	192.01
June			(3.28)	1.52	190.25
July			(3.28)	1.51	188.49
August			(3.28)	1.49	186.70
September			(3.28)	1.48	184.91
October			(3.28)	1.47	183.10
November			(3.28)	1.45	181.28
December			(3.28)	1.44	179.44
January	2006		(3.28)	1.42	177.59
February			(3.28)	1.41	175.72
March			(3.28)	1.39	173.84
April			(3.28)	1.38	171.94
May			(3.28)	1.36	170.03
June			(3.28)	1.35	168.10
July			(3.28)	1.33	166.16
August			(3.28)	1.32	164.20
September			(3.28)	1.30	162.23
October			(3.28)	1.28	160.23
November			(3.28)	1.27	158.23
December			(3.28)	1.25	156.20
January	2007		(3.28)	1.24	154.17
February			(3.28)	1.22	152.11
March			(3.28)	1.20	150.04
April			(3.28)	1.19	147.95
May			(3.28)	1.17	145.84
June			(3.28)	1.15	143.72
July			(3.28)	1.14	141.58
August			(3.28)	1.12	139.43
September			(3.28)	1.10	137.25
October			(3.28)	1.08	135.06
November			(3.28)	1.07	132.85
December			(3.28)	1.05	130.63
January	2008		(3.28)	1.03	128.38

Collect Power Cost Deferral and Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
February			(3.28)	1.01	126.12
March			(3.28)	1.00	123.84
April			(3.28)	0.98	121.55
May			(3.28)	0.96	119.23
June			(3.28)	0.94	116.90
July			(3.28)	0.92	114.54
August			(3.28)	0.90	112.17
September			(3.28)	0.88	109.77
October			(3.28)	0.86	107.36
November			(3.28)	0.85	104.93
December			(3.28)	0.83	102.49
January	2009		(3.28)	0.81	100.02
February			(3.28)	0.79	97.54
March			(3.28)	0.77	95.03
April			(3.28)	0.75	92.51
May			(3.28)	0.73	89.96
June			(3.28)	0.71	87.40
July			(3.28)	0.69	84.81
August			(3.28)	0.67	82.20
September			(3.28)	0.64	79.57
October			(3.28)	0.62	76.91
November			(3.28)	0.60	74.24
December			(3.28)	0.58	71.54
January	2010		(3.28)	0.56	68.83
February			(3.28)	0.54	66.09
March			(3.28)	0.52	63.34
April			(3.28)	0.49	60.55
May			(3.28)	0.47	57.75
June			(3.28)	0.45	54.92
July			(3.28)	0.43	52.08
August			(3.28)	0.40	49.20
September			(3.28)	0.38	46.31
October			(3.28)	0.36	43.39
November			(3.28)	0.33	40.45
December			(3.28)	0.31	37.48
January	2011		(3.28)	0.29	34.50
February			(3.28)	0.26	31.48
March			(3.28)	0.24	28.45
April			(3.28)	0.21	25.38
May			(3.28)	0.19	22.30
June			(3.28)	0.17	19.19
July			(3.28)	0.14	16.06
August			(3.28)	0.12	12.90
September			(3.28)	0.09	9.72
October			(3.28)	0.06	6.50
November			(3.28)	0.04	3.26
December			(3.28)	0.01	(0.00)
Totals		340.16	(658.31)	318.15	(0.00)

Collect Power Cost Deferral and Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month	Accrual	Amortization	Interest on Avg. Balance	Balance
1995 Amounts	278.17	(29.48)	12.09	260.78
1996 Amounts	61.99	(39.30)	29.64	52.33
1997 Amounts	-	(39.30)	29.47	(9.83)
1998 Amounts	-	(39.30)	28.48	(10.82)
1999 Amounts	-	(39.30)	27.41	(11.89)
2000 Amounts	-	(39.30)	26.20	(13.10)
2001 Amounts	-	(39.30)	24.90	(14.40)
2002 Amounts	-	(39.30)	23.46	(15.84)
2003 Amounts	-	(39.30)	21.85	(17.45)
2004 Amounts	-	(39.30)	20.10	(19.20)
2005 Amounts	-	(39.30)	18.18	(21.12)
2006 Amounts	-	(39.30)	16.06	(23.24)
2007 Amounts	-	(39.30)	13.73	(25.57)
2008 Amounts	-	(39.30)	11.16	(28.14)
2009 Amounts	-	(39.30)	8.36	(30.94)
2010 Amounts	-	(39.30)	5.24	(34.06)
2011 Amounts	-	(39.30)	1.82	(37.48)
Totals	340.16	(658.31)	318.15	(0.00)
				(0.00)

Collect Power Cost Deferral over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	20.66	(2.36)	0.07	18.38
May		20.66	(2.36)	0.22	36.90
June		20.66	(2.36)	0.36	55.57
July		20.66	(2.36)	0.51	74.38
August		20.66	(2.36)	0.66	93.35
September		20.66	(2.36)	0.81	112.46
October		20.66	(2.36)	0.96	131.73
November		20.66	(2.36)	1.12	151.16
December		20.66	(2.36)	1.27	170.73
January	1996	20.66	(2.36)	1.44	190.48
February		20.66	(2.36)	1.60	210.38
March		20.66	(2.36)	1.76	230.45
April			(2.36)	1.83	229.92
May			(2.36)	1.83	229.39
June			(2.36)	1.83	228.86
July			(2.36)	1.82	228.32
August			(2.36)	1.82	227.78
September			(2.36)	1.81	227.23
October			(2.36)	1.81	226.68
November			(2.36)	1.80	226.12
December			(2.36)	1.80	225.56
January	1997		(2.36)	1.79	225.00
February			(2.36)	1.79	224.43
March			(2.36)	1.79	223.86
April			(2.36)	1.78	223.28
May			(2.36)	1.78	222.70
June			(2.36)	1.77	222.11
July			(2.36)	1.77	221.52
August			(2.36)	1.76	220.92
September			(2.36)	1.76	220.32
October			(2.36)	1.75	219.71
November			(2.36)	1.75	219.10
December			(2.36)	1.74	218.48
January	1998		(2.36)	1.74	217.86
February			(2.36)	1.73	217.24
March			(2.36)	1.73	216.61
April			(2.36)	1.72	215.97
May			(2.36)	1.72	215.33
June			(2.36)	1.71	214.68
July			(2.36)	1.71	214.03
August			(2.36)	1.70	213.37
September			(2.36)	1.70	212.71
October			(2.36)	1.69	212.04
November			(2.36)	1.69	211.37
December			(2.36)	1.68	210.69
January	1999		(2.36)	1.68	210.01
February			(2.36)	1.67	209.32
March			(2.36)	1.66	208.63
April			(2.36)	1.66	207.93
May			(2.36)	1.65	207.22

Collect Power Cost Deferral over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance	
June			(2.36)	1.65	206.51	
July			(2.36)	1.64	205.79	
August			(2.36)	1.64	205.07	
September			(2.36)	1.63	204.34	
October			(2.36)	1.62	203.60	
November			(2.36)	1.62	202.86	
December			(2.36)	1.61	202.11	
January	2000		(2.36)	1.61	201.36	
February			(2.36)	1.60	200.60	
March			(2.36)	1.59	199.83	
April			(2.36)	1.59	199.06	
May			(2.36)	1.58	198.29	
June			(2.36)	1.58	197.51	
July			(2.36)	1.57	196.72	Total
August			(2.36)	1.56	195.92	Payments
September			(2.36)	1.56	195.12	(155.710)
October			(2.36)	1.55	194.31	
November			(2.36)	1.54	193.49	
December			(2.36)	1.54	192.67	
January	2001		(2.36)	1.53	191.84	
February			(2.36)	1.52	191.00	
March			(2.36)	1.52	190.16	
April			(2.36)	1.51	189.31	
May			(2.36)	1.50	188.45	
June			(2.36)	1.50	187.60	
July			(2.36)	1.49	186.73	
August			(2.36)	1.48	185.85	
September			(2.36)	1.48	184.97	
October			(2.36)	1.47	184.08	
November			(2.36)	1.46	183.18	
December			(2.36)	1.46	182.28	
January	2002		(2.36)	1.45	181.37	
February			(2.36)	1.44	180.45	
March			(2.36)	1.43	179.52	
April			(2.36)	1.43	178.59	
May			(2.36)	1.42	177.65	
June			(2.36)	1.41	176.70	
July			(2.36)	1.40	175.75	
August			(2.36)	1.40	174.79	
September			(2.36)	1.39	173.82	
October			(2.36)	1.38	172.84	
November			(2.36)	1.37	171.85	
December			(2.36)	1.37	170.86	
January	2003		(2.36)	1.36	169.86	
February			(2.36)	1.35	168.85	
March			(2.36)	1.34	167.83	
April			(2.36)	1.33	166.80	
May			(2.36)	1.32	165.76	
June			(2.36)	1.32	164.72	
July			(2.36)	1.31	163.67	
August			(2.36)	1.30	162.62	
September			(2.36)	1.29	161.55	

Collect Power Cost Deferral over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
October			(2.36)	1.28	160.47
November			(2.36)	1.27	159.38
December			(2.36)	1.27	158.29
January	2004		(2.36)	1.26	157.19
February			(2.36)	1.25	156.08
March			(2.36)	1.24	154.96
April			(2.36)	1.23	153.83
May			(2.36)	1.22	152.69
June			(2.36)	1.21	151.54
July			(2.36)	1.20	150.38
August			(2.36)	1.19	149.21
September			(2.36)	1.18	148.04
October			(2.36)	1.17	146.85
November			(2.36)	1.17	145.66
December			(2.36)	1.16	144.46
January	2005		(2.36)	1.15	143.25
February			(2.36)	1.14	142.03
March			(2.36)	1.13	140.80
April			(2.36)	1.12	139.56
May			(2.36)	1.11	138.31
June			(2.36)	1.10	137.05
July			(2.36)	1.09	135.78
August			(2.36)	1.08	134.50
September			(2.36)	1.07	133.21
October			(2.36)	1.06	131.91
November			(2.36)	1.05	130.61
December			(2.36)	1.04	129.29
January	2006		(2.36)	1.02	127.95
February			(2.36)	1.01	126.60
March			(2.36)	1.00	125.24
April			(2.36)	0.99	123.87
May			(2.36)	0.98	122.49
June			(2.36)	0.97	121.10
July			(2.36)	0.96	119.70
August			(2.36)	0.95	118.29
September			(2.36)	0.94	116.87
October			(2.36)	0.93	115.44
November			(2.36)	0.91	113.99
December			(2.36)	0.90	112.54
January	2007		(2.36)	0.89	111.07
February			(2.36)	0.88	109.59
March			(2.36)	0.87	108.10
April			(2.36)	0.86	106.60
May			(2.36)	0.84	105.08
June			(2.36)	0.83	103.55
July			(2.36)	0.82	102.01
August			(2.36)	0.81	100.46
September			(2.36)	0.79	98.89
October			(2.36)	0.78	97.31
November			(2.36)	0.77	95.72
December			(2.36)	0.76	94.12
January	2008		(2.36)	0.74	92.51

Collect Power Cost Deferral over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
February			(2.36)	0.73	90.88
March			(2.36)	0.72	89.24
April			(2.36)	0.70	87.58
May			(2.36)	0.69	85.91
June			(2.36)	0.68	84.23
July			(2.36)	0.66	82.53
August			(2.36)	0.65	80.82
September			(2.36)	0.64	79.10
October			(2.36)	0.62	77.36
November			(2.36)	0.61	75.61
December			(2.36)	0.60	73.85
January	2009		(2.36)	0.58	72.07
February			(2.36)	0.57	70.29
March			(2.36)	0.55	68.48
April			(2.36)	0.54	66.66
May			(2.36)	0.52	64.82
June			(2.36)	0.51	62.97
July			(2.36)	0.49	61.10
August			(2.36)	0.48	59.22
September			(2.36)	0.46	57.32
October			(2.36)	0.45	55.41
November			(2.36)	0.43	53.48
December			(2.36)	0.42	51.54
January	2010		(2.36)	0.40	49.58
February			(2.36)	0.39	47.61
March			(2.36)	0.37	45.63
April			(2.36)	0.36	43.63
May			(2.36)	0.34	41.61
June			(2.36)	0.32	39.57
July			(2.36)	0.31	37.52
August			(2.36)	0.29	35.45
September			(2.36)	0.27	33.36
October			(2.36)	0.26	31.26
November			(2.36)	0.24	29.14
December			(2.36)	0.22	27.00
January	2011		(2.36)	0.21	24.85
February			(2.36)	0.19	22.68
March			(2.36)	0.17	20.49
April			(2.36)	0.15	18.28
May			(2.36)	0.14	16.07
June			(2.36)	0.12	13.83
July			(2.36)	0.10	11.57
August			(2.36)	0.08	9.29
September			(2.36)	0.06	6.99
October			(2.36)	0.05	4.68
November			(2.36)	0.03	2.35
December			(2.36)	0.01	0.00
Totals		247.98	(474.21)	226.23	0.00

Collect Power Cost Deferral over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month	Accrual	Amortization	Interest on Avg. Balance	Balance
1995 Amounts	185.98	(21.23)	5.98	170.73
1996 Amounts	61.99	(28.31)	21.15	54.83
1997 Amounts	-	(28.31)	21.23	(7.08)
1998 Amounts	-	(28.31)	20.52	(7.79)
1999 Amounts	-	(28.31)	19.73	(8.58)
2000 Amounts	-	(28.31)	18.87	(9.44)
2001 Amounts	-	(28.31)	17.92	(10.39)
2002 Amounts	-	(28.31)	16.89	(11.42)
2003 Amounts	-	(28.31)	15.74	(12.57)
2004 Amounts	-	(28.31)	14.48	(13.83)
2005 Amounts	-	(28.31)	13.14	(15.17)
2006 Amounts	-	(28.31)	11.56	(16.75)
2007 Amounts	-	(28.31)	9.90	(18.41)
2008 Amounts	-	(28.31)	8.04	(20.27)
2009 Amounts	-	(28.31)	6.00	(22.31)
2010 Amounts	-	(28.31)	3.77	(24.54)
2011 Amounts	-	(28.31)	1.31	(27.00)
Totals	247.98	(474.21)	226.23	0.00
				0.00

Collect Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	92.18	(0.92)	0.36	91.63
May			(0.92)	0.72	91.43
June			(0.92)	0.72	91.24
July			(0.92)	0.72	91.04
August			(0.92)	0.72	90.85
September			(0.92)	0.72	90.65
October			(0.92)	0.71	90.45
November			(0.92)	0.71	90.24
December			(0.92)	0.71	90.03
January	1996		(0.92)	0.72	89.84
February			(0.92)	0.71	89.63
March			(0.92)	0.71	89.43
April			(0.92)	0.71	89.22
May			(0.92)	0.71	89.02
June			(0.92)	0.71	88.81
July			(0.92)	0.71	88.61
August			(0.92)	0.71	88.40
September			(0.92)	0.70	88.19
October			(0.92)	0.70	87.97
November			(0.92)	0.70	87.75
December			(0.92)	0.70	87.54
January	1997		(0.92)	0.70	87.32
February			(0.92)	0.69	87.10
March			(0.92)	0.69	86.87
April			(0.92)	0.69	86.65
May			(0.92)	0.69	86.42
June			(0.92)	0.69	86.20
July			(0.92)	0.69	85.97
August			(0.92)	0.68	85.74
September			(0.92)	0.68	85.50
October			(0.92)	0.68	85.27
November			(0.92)	0.68	85.03
December			(0.92)	0.68	84.79
January	1998		(0.92)	0.67	84.55
February			(0.92)	0.67	84.30
March			(0.92)	0.67	84.06
April			(0.92)	0.67	83.81
May			(0.92)	0.67	83.57
June			(0.92)	0.66	83.31
July			(0.92)	0.66	83.06
August			(0.92)	0.66	82.80
September			(0.92)	0.66	82.55
October			(0.92)	0.66	82.29
November			(0.92)	0.65	82.03
December			(0.92)	0.65	81.76
January	1999		(0.92)	0.65	81.49
February			(0.92)	0.65	81.23
March			(0.92)	0.65	80.96
April			(0.92)	0.64	80.69
May			(0.92)	0.64	80.41

Collect Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance	
June			(0.92)	0.64	80.14	
July			(0.92)	0.64	79.86	
August			(0.92)	0.64	79.59	
September			(0.92)	0.63	79.30	
October			(0.92)	0.63	79.02	
November			(0.92)	0.63	78.73	
December			(0.92)	0.63	78.44	
January	2000		(0.92)	0.62	78.15	
February			(0.92)	0.62	77.85	
March			(0.92)	0.62	77.56	
April			(0.92)	0.62	77.26	
May			(0.92)	0.61	76.96	
June			(0.92)	0.61	76.65	
July			(0.92)	0.61	76.35	Total
August			(0.92)	0.61	76.04	Payments
September			(0.92)	0.60	75.73	(60.417)
October			(0.92)	0.60	75.41	
November			(0.92)	0.60	75.10	
December			(0.92)	0.60	74.78	
January	2001		(0.92)	0.59	74.45	
February			(0.92)	0.59	74.13	
March			(0.92)	0.59	73.80	
April			(0.92)	0.59	73.48	
May			(0.92)	0.58	73.14	
June			(0.92)	0.58	72.81	
July			(0.92)	0.58	72.47	
August			(0.92)	0.58	72.14	
September			(0.92)	0.57	71.79	
October			(0.92)	0.57	71.45	
November			(0.92)	0.57	71.10	
December			(0.92)	0.56	70.75	
January	2002		(0.92)	0.56	70.39	
February			(0.92)	0.56	70.03	
March			(0.92)	0.56	69.68	
April			(0.92)	0.55	69.31	
May			(0.92)	0.55	68.95	
June			(0.92)	0.55	68.58	
July			(0.92)	0.54	68.21	
August			(0.92)	0.54	67.83	
September			(0.92)	0.54	67.46	
October			(0.92)	0.54	67.08	
November			(0.92)	0.53	66.70	
December			(0.92)	0.53	66.31	
January	2003		(0.92)	0.53	65.92	
February			(0.92)	0.52	65.53	
March			(0.92)	0.52	65.13	
April			(0.92)	0.52	64.74	
May			(0.92)	0.51	64.33	
June			(0.92)	0.51	63.93	
July			(0.92)	0.51	63.52	
August			(0.92)	0.50	63.11	
September			(0.92)	0.50	62.69	

Collect Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
October			(0.92)	0.50	62.28
November			(0.92)	0.49	61.85
December			(0.92)	0.49	61.43
January	2004		(0.92)	0.49	61.00
February			(0.92)	0.48	60.56
March			(0.92)	0.48	60.13
April			(0.92)	0.48	59.69
May			(0.92)	0.47	59.25
June			(0.92)	0.47	58.80
July			(0.92)	0.47	58.36
August			(0.92)	0.46	57.90
September			(0.92)	0.46	57.45
October			(0.92)	0.46	56.99
November			(0.92)	0.45	56.53
December			(0.92)	0.45	56.06
January	2005		(0.92)	0.44	55.58
February			(0.92)	0.44	55.11
March			(0.92)	0.44	54.63
April			(0.92)	0.43	54.15
May			(0.92)	0.43	53.66
June			(0.92)	0.43	53.18
July			(0.92)	0.42	52.68
August			(0.92)	0.42	52.19
September			(0.92)	0.41	51.68
October			(0.92)	0.41	51.18
November			(0.92)	0.41	50.67
December			(0.92)	0.40	50.16
January	2006		(0.92)	0.40	49.64
February			(0.92)	0.39	49.11
March			(0.92)	0.39	48.59
April			(0.92)	0.38	48.05
May			(0.92)	0.38	47.52
June			(0.92)	0.38	46.98
July			(0.92)	0.37	46.44
August			(0.92)	0.37	45.89
September			(0.92)	0.36	45.34
October			(0.92)	0.36	44.78
November			(0.92)	0.35	44.22
December			(0.92)	0.35	43.65
January	2007		(0.92)	0.35	43.09
February			(0.92)	0.34	42.51
March			(0.92)	0.34	41.93
April			(0.92)	0.33	41.35
May			(0.92)	0.33	40.76
June			(0.92)	0.32	40.17
July			(0.92)	0.32	39.57
August			(0.92)	0.31	38.97
September			(0.92)	0.31	38.36
October			(0.92)	0.30	37.75
November			(0.92)	0.30	37.13
December			(0.92)	0.29	36.51
January	2008		(0.92)	0.29	35.88

Collect Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
February			(0.92)	0.28	35.24
March			(0.92)	0.28	34.61
April			(0.92)	0.27	33.96
May			(0.92)	0.27	33.32
June			(0.92)	0.26	32.66
July			(0.92)	0.26	32.01
August			(0.92)	0.25	31.34
September			(0.92)	0.25	30.68
October			(0.92)	0.24	30.00
November			(0.92)	0.24	29.33
December			(0.92)	0.23	28.64
January	2009		(0.92)	0.23	27.96
February			(0.92)	0.22	27.26
March			(0.92)	0.21	26.55
April			(0.92)	0.21	25.85
May			(0.92)	0.20	25.13
June			(0.92)	0.20	24.42
July			(0.92)	0.19	23.69
August			(0.92)	0.19	22.97
September			(0.92)	0.18	22.23
October			(0.92)	0.17	21.49
November			(0.92)	0.17	20.74
December			(0.92)	0.16	19.99
January	2010		(0.92)	0.16	19.23
February			(0.92)	0.15	18.47
March			(0.92)	0.14	17.69
April			(0.92)	0.14	16.91
May			(0.92)	0.13	16.13
June			(0.92)	0.13	15.34
July			(0.92)	0.12	14.55
August			(0.92)	0.11	13.74
September			(0.92)	0.11	12.94
October			(0.92)	0.10	12.12
November			(0.92)	0.09	11.30
December			(0.92)	0.09	10.47
January	2011		(0.92)	0.08	9.64
February			(0.92)	0.07	8.79
March			(0.92)	0.07	7.94
April			(0.92)	0.06	7.09
May			(0.92)	0.05	6.22
June			(0.92)	0.05	5.36
July			(0.92)	0.04	4.48
August			(0.92)	0.03	3.60
September			(0.92)	0.03	2.71
October			(0.92)	0.02	1.82
November			(0.92)	0.01	0.91
December			(0.92)	-	(0.00)
	Totals	92.18	(184.00)	91.81	(0.00)

Collect Reg Assets over 17 years
Trojan Balance at UE-88 authorized level (plus partial restoration, net of Boardman credit)
Dollars in Millions

Month	Accrual	Amortization	Interest on Avg. Balance	Balance
1995 Amounts	92.18	(8.24)	6.09	90.03
1996 Amounts	-	(10.98)	8.49	(2.49)
1997 Amounts	-	(10.98)	8.24	(2.74)
1998 Amounts	-	(10.98)	7.95	(3.03)
1999 Amounts	-	(10.98)	7.67	(3.31)
2000 Amounts	-	(10.98)	7.32	(3.66)
2001 Amounts	-	(10.98)	6.95	(4.03)
2002 Amounts	-	(10.98)	6.55	(4.43)
2003 Amounts	-	(10.98)	6.10	(4.88)
2004 Amounts	-	(10.98)	5.62	(5.36)
2005 Amounts	-	(10.98)	5.08	(5.90)
2006 Amounts	-	(10.98)	4.48	(6.50)
2007 Amounts	-	(10.98)	3.84	(7.14)
2008 Amounts	-	(10.98)	3.12	(7.86)
2009 Amounts	-	(10.98)	2.33	(8.65)
2010 Amounts	-	(10.98)	1.47	(9.51)
2011 Amounts	-	(10.98)	0.51	(10.47)
Totals	92.18	(184.00)	91.81	(0.00)
				(0.00)

Description: Collect Trojan classified as plant-in-service over 17 year with no return on, adjust Net Benefits Test for SG, and lost PV of no "return on". Reduce Trojan balance with the entirety of the Boardman gain.
Collect SAVE,AMAX, Trojan Replacement Power Costs over 3 years through March 1998.

Trojan Balance @4/1/1995	259.96
Boardman Gain Balance @ 4/1/1995	(111.15)
Adjustment to Net Benefit Test	26.83
New Trojan Balance @ 4/1/1995	175.64

Reg Asset Balances @ 4/1/1995 (Items offset by Boardman Gain):

Trojan Pwr Cost Deferrals	48.46	All per Order 95-2116
AMAX	15.84	
SAVE	27.88	
Total	92.18	3-Yr Collection

AMAX,SAVE,Trojan Replacement Power Cost Collection, Includes 150 BP ROE Increase
3-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance	
April	1995	92.18	(2.96)	0.38	89.60	
May			(2.96)	0.75	87.39	
June			(2.96)	0.73	85.16	
July			(2.96)	0.71	82.91	
August			(2.96)	0.69	80.64	
September			(2.96)	0.67	78.35	
October			(2.96)	0.65	76.04	
November			(2.96)	0.63	73.71	
December			(2.96)	0.61	71.36	
January	1996		(2.96)	0.60	69.01	
February			(2.96)	0.58	66.63	
March			(2.96)	0.56	64.23	
April			(2.96)	0.54	61.81	
May			(2.96)	0.52	59.37	
June			(2.96)	0.50	56.91	
July			(2.96)	0.48	54.43	
August			(2.96)	0.45	51.92	
September			(2.96)	0.43	49.39	
October			(2.96)	0.41	46.84	
November			(2.96)	0.39	44.27	
December			(2.96)	0.37	41.68	
January	1997		(2.96)	0.34	39.06	
February			(2.96)	0.32	36.42	
March			(2.96)	0.30	33.76	
April			(2.96)	0.28	31.08	
May			(2.96)	0.25	28.37	
June			(2.96)	0.23	25.64	
July			(2.96)	0.21	22.89	
August			(2.96)	0.18	20.11	
September			(2.96)	0.16	17.31	
October			(2.96)	0.14	14.49	
November			(2.96)	0.11	11.64	
December			(2.96)	0.09	8.77	
January	1998		(2.96)	0.06	5.87	
February			(2.96)	0.04	2.95	
March			(2.96)	0.01	0.00	(106.55)
	Totals	92.18	(106.55)	14.37	0.00	
	1995 Amounts	92.18	(26.64)	5.82	71.36	
	1996 Amounts	-	(35.52)	5.83	(29.69)	
	1997 Amounts	-	(35.52)	2.61	(32.91)	
	1998 Amounts	-	(8.88)	0.11	(8.77)	
	Totals	92.18	(106.55)	14.37	0.00	
					0.00	

Description: Collect Trojan classified as plant-in-service over 1 year with no return on, adjust Net Benefits Test for SG, and lost PV of no "return on". Reduce Trojan balance with the entirety of the Boardman gain.
Add UE-88 Power Cost Deferral to achieve intergenerational equity.
Collect Power Cost Deferral, SAVE,AMAX, Trojan Replacement Power Costs over 10 years through March 2005.

Trojan Balance @4/1/1995	340.16
Plant Classified as In-Service	(80.20)
Boardman Gain Balance @ 4/1/1995	(111.15)
Adjustment to Net Benefit Test	26.83
New Trojan Balance @ 4/1/1995	175.64
UE 88 Power Costs - 1st year	309.30

Reg Asset Balances @ 4/1/1995 (Items offset by Boardman Gain):		
Trojan Pwr Cost Deferrals	48.46	All per Order 95-2116
AMAX	15.84	
SAVE	27.88	
Total	92.18	10-Yr Collection
UE-88 Power Cost Forecast	309.30	Avg per Order 95-322
New Reg Asset - Power Costs	137.78	10-Yr Collection
1st Yr Collection of Power Costs	171.52	
Total Reg Assets @ 4/1/1995	229.96	

Deferred Power Cost and Reg Asset Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	103.66	(2.90)	0.40	101.16
May		11.48	(2.90)	0.85	110.60
June		11.48	(2.90)	0.92	120.10
July		11.48	(2.90)	1.00	129.68
August		11.48	(2.90)	1.07	139.33
September		11.48	(2.90)	1.15	149.06
October		11.48	(2.90)	1.23	158.87
November		11.48	(2.90)	1.31	168.76
December		11.48	(2.90)	1.39	178.73
January	1996	11.48	(2.90)	1.48	188.79
February		11.48	(2.90)	1.56	198.93
March		11.48	(2.90)	1.65	209.17
April			(2.90)	1.68	207.95
May			(2.90)	1.67	206.71
June			(2.90)	1.66	205.47
July			(2.90)	1.65	204.22
August			(2.90)	1.64	202.96
September			(2.90)	1.63	201.69
October			(2.90)	1.62	200.41
November			(2.90)	1.61	199.12
December			(2.90)	1.60	197.82
January	1997		(2.90)	1.59	196.51
February			(2.90)	1.58	195.19
March			(2.90)	1.57	193.86
April			(2.90)	1.56	192.52
May			(2.90)	1.55	191.17
June			(2.90)	1.54	189.81
July			(2.90)	1.52	188.43
August			(2.90)	1.51	187.04
September			(2.90)	1.50	185.64
October			(2.90)	1.49	184.23
November			(2.90)	1.48	182.81
December			(2.90)	1.47	181.37
January	1998		(2.90)	1.46	179.93
February			(2.90)	1.44	178.47
March			(2.90)	1.43	177.00
April			(2.90)	1.42	175.52
May			(2.90)	1.41	174.03
June			(2.90)	1.40	172.53
July			(2.90)	1.38	171.01
August			(2.90)	1.37	169.48
September			(2.90)	1.36	167.94
October			(2.90)	1.35	166.39
November			(2.90)	1.34	164.83
December			(2.90)	1.32	163.25
January	1999		(2.90)	1.31	161.66
February			(2.90)	1.30	160.06
March			(2.90)	1.28	158.44
April			(2.90)	1.27	156.81
May			(2.90)	1.26	155.17

Deferred Power Cost and Reg Asset Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance	
June			(2.90)	1.24	153.51	
July			(2.90)	1.23	151.84	
August			(2.90)	1.22	150.15	
September			(2.90)	1.20	148.45	
October			(2.90)	1.19	146.74	
November			(2.90)	1.18	145.02	
December			(2.90)	1.16	143.28	
January	2000		(2.90)	1.15	141.53	
February			(2.90)	1.13	139.76	
March			(2.90)	1.12	137.98	
April			(2.90)	1.11	136.19	
May			(2.90)	1.09	134.38	
June			(2.90)	1.08	132.56	
July			(2.90)	1.06	130.72	Total
August			(2.90)	1.05	128.87	Payments
September			(2.90)	1.03	127.00	(191.434)
October			(2.90)	1.02	125.12	
November			(2.90)	1.00	123.22	
December			(2.90)	0.99	121.31	
January	2001		(2.90)	0.97	119.38	
February			(2.90)	0.95	117.43	
March			(2.90)	0.94	115.46	
April			(2.90)	0.92	113.48	
May			(2.90)	0.91	111.49	
June			(2.90)	0.89	109.48	
July			(2.90)	0.87	107.45	
August			(2.90)	0.86	105.41	
September			(2.90)	0.84	103.35	
October			(2.90)	0.82	101.27	
November			(2.90)	0.81	99.18	
December			(2.90)	0.79	97.07	
January	2002		(2.90)	0.77	94.94	
February			(2.90)	0.76	92.80	
March			(2.90)	0.74	90.64	
April			(2.90)	0.72	88.46	
May			(2.90)	0.70	86.26	
June			(2.90)	0.69	84.05	
July			(2.90)	0.67	81.82	
August			(2.90)	0.65	79.57	
September			(2.90)	0.63	77.30	
October			(2.90)	0.61	75.00	
November			(2.90)	0.60	72.70	
December			(2.90)	0.58	70.38	
January	2003		(2.90)	0.56	68.04	
February			(2.90)	0.54	65.68	
March			(2.90)	0.52	63.30	
April			(2.90)	0.50	60.90	
May			(2.90)	0.48	58.48	
June			(2.90)	0.46	56.04	
July			(2.90)	0.44	53.58	
August			(2.90)	0.42	51.10	
September			(2.90)	0.40	48.60	

Deferred Power Cost and Reg Asset Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
October			(2.90)	0.38	46.08
November			(2.90)	0.36	43.54
December			(2.90)	0.34	40.98
January	2004		(2.90)	0.32	38.40
February			(2.90)	0.30	35.80
March			(2.90)	0.28	33.18
April			(2.90)	0.26	30.54
May			(2.90)	0.24	27.88
June			(2.90)	0.21	25.18
July			(2.90)	0.19	22.47
August			(2.90)	0.17	19.74
September			(2.90)	0.15	16.99
October			(2.90)	0.13	14.22
November			(2.90)	0.10	11.42
December			(2.90)	0.08	8.60
January	2005		(2.90)	0.06	5.76
February			(2.90)	0.03	2.89
March			(2.90)	0.01	0.00
	Totals	229.96	(348.06)	118.10	0.00
	1995 Amounts	195.52	(26.10)	9.32	178.73
	1996 Amounts	34.44	(34.81)	19.45	19.09
	1997 Amounts	-	(34.81)	18.36	(16.45)
	1998 Amounts	-	(34.81)	16.68	(18.13)
	1999 Amounts	-	(34.81)	14.84	(19.97)
	2000 Amounts	-	(34.81)	12.83	(21.98)
	2001 Amounts	-	(34.81)	10.57	(24.24)
	2002 Amounts	-	(34.81)	8.12	(26.69)
	2003 Amounts	-	(34.81)	5.40	(29.41)
	2004 Amounts	-	(34.81)	2.43	(32.38)
	2005 Amounts	-	(8.70)	0.10	(8.60)
	Totals	229.96	(348.06)	118.10	0.00
					0.00

Deferred Power Cost Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	11.48	(1.71)	0.04	9.81
May		11.48	(1.71)	0.12	19.71
June		11.48	(1.71)	0.20	29.68
July		11.48	(1.71)	0.28	39.74
August		11.48	(1.71)	0.36	49.87
September		11.48	(1.71)	0.44	60.08
October		11.48	(1.71)	0.52	70.38
November		11.48	(1.71)	0.60	80.75
December		11.48	(1.71)	0.69	91.22
January	1996	11.48	(1.71)	0.78	101.77
February		11.48	(1.71)	0.86	112.41
March		11.48	(1.71)	0.95	123.13
April			(1.71)	0.99	122.41
May			(1.71)	0.98	121.69
June			(1.71)	0.98	120.96
July			(1.71)	0.97	120.22
August			(1.71)	0.97	119.48
September			(1.71)	0.96	118.74
October			(1.71)	0.95	117.98
November			(1.71)	0.95	117.22
December			(1.71)	0.94	116.45
January	1997		(1.71)	0.94	115.69
February			(1.71)	0.93	114.91
March			(1.71)	0.92	114.12
April			(1.71)	0.92	113.33
May			(1.71)	0.91	112.54
June			(1.71)	0.90	111.73
July			(1.71)	0.90	110.92
August			(1.71)	0.89	110.10
September			(1.71)	0.88	109.28
October			(1.71)	0.88	108.45
November			(1.71)	0.87	107.61
December			(1.71)	0.86	106.76
January	1998		(1.71)	0.86	105.92
February			(1.71)	0.85	105.06
March			(1.71)	0.84	104.19
April			(1.71)	0.84	103.32
May			(1.71)	0.83	102.45
June			(1.71)	0.82	101.56
July			(1.71)	0.82	100.67
August			(1.71)	0.81	99.78
September			(1.71)	0.80	98.87
October			(1.71)	0.79	97.95
November			(1.71)	0.79	97.03
December			(1.71)	0.78	96.11
January	1999		(1.71)	0.77	95.17
February			(1.71)	0.76	94.22
March			(1.71)	0.76	93.27
April			(1.71)	0.75	92.32
May			(1.71)	0.74	91.35

Deferred Power Cost Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance	
June			(1.71)	0.73	90.37	
July			(1.71)	0.72	89.38	
August			(1.71)	0.72	88.40	
September			(1.71)	0.71	87.40	
October			(1.71)	0.70	86.39	
November			(1.71)	0.69	85.37	
December			(1.71)	0.68	84.35	
January	2000		(1.71)	0.68	83.32	
February			(1.71)	0.67	82.28	
March			(1.71)	0.66	81.23	
April			(1.71)	0.65	80.18	
May			(1.71)	0.64	79.11	
June			(1.71)	0.63	78.03	
July			(1.71)	0.62	76.94	Total
August			(1.71)	0.62	75.86	Payments
September			(1.71)	0.61	74.76	(112.689)
October			(1.71)	0.60	73.65	
November			(1.71)	0.59	72.54	
December			(1.71)	0.58	71.41	
January	2001		(1.71)	0.57	70.27	
February			(1.71)	0.56	69.12	
March			(1.71)	0.55	67.97	
April			(1.71)	0.54	66.80	
May			(1.71)	0.53	65.62	
June			(1.71)	0.52	64.43	
July			(1.71)	0.51	63.24	
August			(1.71)	0.50	62.03	
September			(1.71)	0.50	60.82	
October			(1.71)	0.49	59.60	
November			(1.71)	0.48	58.38	
December			(1.71)	0.47	57.14	
January	2002		(1.71)	0.46	55.89	
February			(1.71)	0.45	54.63	
March			(1.71)	0.44	53.37	
April			(1.71)	0.43	52.09	
May			(1.71)	0.41	50.79	
June			(1.71)	0.40	49.48	
July			(1.71)	0.39	48.17	
August			(1.71)	0.38	46.84	
September			(1.71)	0.37	45.50	
October			(1.71)	0.36	44.15	
November			(1.71)	0.35	42.80	
December			(1.71)	0.34	41.43	
January	2003		(1.71)	0.33	40.05	
February			(1.71)	0.32	38.67	
March			(1.71)	0.31	37.27	
April			(1.71)	0.29	35.85	
May			(1.71)	0.28	34.42	
June			(1.71)	0.27	32.99	
July			(1.71)	0.26	31.54	
August			(1.71)	0.25	30.08	
September			(1.71)	0.24	28.61	

Deferred Power Cost Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
October			(1.71)	0.22	27.13
November			(1.71)	0.21	25.63
December			(1.71)	0.20	24.12
January	2004		(1.71)	0.19	22.60
February			(1.71)	0.18	21.08
March			(1.71)	0.16	19.53
April			(1.71)	0.15	17.97
May			(1.71)	0.14	16.40
June			(1.71)	0.13	14.83
July			(1.71)	0.11	13.23
August			(1.71)	0.10	11.62
September			(1.71)	0.09	10.00
October			(1.71)	0.07	8.37
November			(1.71)	0.06	6.72
December			(1.71)	0.05	5.06
January	2005		(1.71)	0.03	3.38
February			(1.71)	0.02	1.70
March			(1.71)	0.01	0.00
	Totals	137.78	(204.89)	67.11	0.00
	1995 Amounts	103.33	(15.37)	3.25	91.22
	1996 Amounts	34.44	(20.49)	11.28	25.24
	1997 Amounts	-	(20.49)	10.80	(9.69)
	1998 Amounts	-	(20.49)	9.83	(10.66)
	1999 Amounts	-	(20.49)	8.73	(11.76)
	2000 Amounts	-	(20.49)	7.55	(12.94)
	2001 Amounts	-	(20.49)	6.22	(14.27)
	2002 Amounts	-	(20.49)	4.78	(15.71)
	2003 Amounts	-	(20.49)	3.18	(17.31)
	2004 Amounts	-	(20.49)	1.43	(19.06)
	2005 Amounts	-	(5.12)	0.06	(5.06)
	Totals	137.78	(204.89)	67.11	-
					0.00

AMAX,SAVE,Trojan Replacement Power Cost Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
April	1995	92.18	(1.19)	0.36	91.35
May			(1.19)	0.73	90.89
June			(1.19)	0.72	90.41
July			(1.19)	0.72	89.94
August			(1.19)	0.72	89.47
September			(1.19)	0.71	88.99
October			(1.19)	0.71	88.50
November			(1.19)	0.70	88.01
December			(1.19)	0.70	87.52
January	1996		(1.19)	0.70	87.02
February			(1.19)	0.70	86.53
March			(1.19)	0.70	86.04
April			(1.19)	0.69	85.53
May			(1.19)	0.69	85.03
June			(1.19)	0.68	84.52
July			(1.19)	0.68	84.01
August			(1.19)	0.68	83.49
September			(1.19)	0.67	82.97
October			(1.19)	0.67	82.45
November			(1.19)	0.66	81.91
December			(1.19)	0.66	81.38
January	1997		(1.19)	0.65	80.84
February			(1.19)	0.65	80.29
March			(1.19)	0.65	79.75
April			(1.19)	0.64	79.20
May			(1.19)	0.64	78.65
June			(1.19)	0.63	78.08
July			(1.19)	0.63	77.52
August			(1.19)	0.62	76.95
September			(1.19)	0.62	76.37
October			(1.19)	0.61	75.79
November			(1.19)	0.61	75.21
December			(1.19)	0.60	74.62
January	1998		(1.19)	0.60	74.02
February			(1.19)	0.59	73.42
March			(1.19)	0.59	72.82
April			(1.19)	0.58	72.20
May			(1.19)	0.58	71.59
June			(1.19)	0.57	70.97
July			(1.19)	0.57	70.34
August			(1.19)	0.56	69.71
September			(1.19)	0.56	69.08
October			(1.19)	0.55	68.44
November			(1.19)	0.55	67.79
December			(1.19)	0.54	67.14
January	1999		(1.19)	0.54	66.49
February			(1.19)	0.53	65.82
March			(1.19)	0.53	65.16
April			(1.19)	0.52	64.49
May			(1.19)	0.52	63.81

AMAX,SAVE,Trojan Replacement Power Cost Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance	
June			(1.19)	0.51	63.13	
July			(1.19)	0.51	62.45	
August			(1.19)	0.50	61.76	
September			(1.19)	0.50	61.06	
October			(1.19)	0.49	60.36	
November			(1.19)	0.48	59.65	
December			(1.19)	0.48	58.93	
January	2000		(1.19)	0.47	58.21	
February			(1.19)	0.47	57.49	
March			(1.19)	0.46	56.75	
April			(1.19)	0.45	56.01	
May			(1.19)	0.45	55.27	
June			(1.19)	0.44	54.52	
July			(1.19)	0.44	53.76	Total
August			(1.19)	0.43	53.00	Payments
September			(1.19)	0.42	52.23	(78.736)
October			(1.19)	0.42	51.45	
November			(1.19)	0.41	50.67	
December			(1.19)	0.41	49.89	
January	2001		(1.19)	0.40	49.10	
February			(1.19)	0.39	48.29	
March			(1.19)	0.39	47.49	
April			(1.19)	0.38	46.68	
May			(1.19)	0.37	45.85	
June			(1.19)	0.37	45.03	
July			(1.19)	0.36	44.20	
August			(1.19)	0.35	43.35	
September			(1.19)	0.35	42.51	
October			(1.19)	0.34	41.66	
November			(1.19)	0.33	40.80	
December			(1.19)	0.33	39.93	
January	2002		(1.19)	0.32	39.06	
February			(1.19)	0.31	38.18	
March			(1.19)	0.30	37.28	
April			(1.19)	0.30	36.39	
May			(1.19)	0.29	35.49	
June			(1.19)	0.28	34.57	
July			(1.19)	0.28	33.66	
August			(1.19)	0.27	32.74	
September			(1.19)	0.26	31.81	
October			(1.19)	0.25	30.86	
November			(1.19)	0.25	29.92	
December			(1.19)	0.24	28.97	
January	2003		(1.19)	0.23	28.00	
February			(1.19)	0.22	27.03	
March			(1.19)	0.21	26.05	
April			(1.19)	0.21	25.07	
May			(1.19)	0.20	24.07	
June			(1.19)	0.19	23.07	
July			(1.19)	0.18	22.06	
August			(1.19)	0.17	21.03	
September			(1.19)	0.17	20.01	

AMAX,SAVE,Trojan Replacement Power Cost Collection, Includes 25 BP ROE Increase
10-Year Amortization Period
Dollars in Millions

Month		Accrual	Amortization	Interest on Avg. Balance	Balance
October			(1.19)	0.16	18.98
November			(1.19)	0.15	17.93
December			(1.19)	0.14	16.88
January	2004		(1.19)	0.13	15.82
February			(1.19)	0.12	14.75
March			(1.19)	0.11	13.66
April			(1.19)	0.11	12.58
May			(1.19)	0.10	11.49
June			(1.19)	0.09	10.38
July			(1.19)	0.08	9.27
August			(1.19)	0.07	8.15
September			(1.19)	0.06	7.01
October			(1.19)	0.05	5.87
November			(1.19)	0.04	4.72
December			(1.19)	0.03	3.56
January	2005		(1.19)	0.02	2.38
February			(1.19)	0.01	1.20
March			(1.19)	-	0.01
	Totals	92.18	(143.16)	50.98	0.01
	1995 Amounts	92.18	(10.74)	6.07	87.52
	1996 Amounts	-	(14.32)	8.18	(6.14)
	1997 Amounts	-	(14.32)	7.55	(6.77)
	1998 Amounts	-	(14.32)	6.84	(7.48)
	1999 Amounts	-	(14.32)	6.11	(8.21)
	2000 Amounts	-	(14.32)	5.27	(9.05)
	2001 Amounts	-	(14.32)	4.36	(9.96)
	2002 Amounts	-	(14.32)	3.35	(10.97)
	2003 Amounts	-	(14.32)	2.23	(12.09)
	2004 Amounts	-	(14.32)	0.99	(13.33)
	2005 Amounts	-	(3.58)	0.03	(3.55)
	Totals	92.18	(143.16)	50.98	0.01
					0.01

Support for Lesh Testimony

Combination 1

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirement	Difference
UE 88	621,028	627,510	6,482
UE 93	1,003,794	1,011,340	7,546
UE 100	3,674,898	3,679,829	4,931
Total	5,299,719	5,318,678	18,959

Combination 2

Rate Period	Approved Revenue Requirement	Re-Calculated Revenue Requirement	Difference
UE 88	621,028	621,090	63
UE 93	1,003,794	1,029,157	25,363
UE 100	3,674,898	3,707,946	33,048
Total	5,299,719	5,358,194	58,474

Trojan Balances for Scenarios
Dollars in 000s

For 1 year Amort Scenario - Partial Restoration

Balance @ 4/1/1995	340,162
Restoration of UE-88 Net Benefit Write-off	23,108
Net Trojan	363,270

For 1 year Amort Scenario - Full Restoration

Balance @ 4/1/1995	340,162
Boardman Gain	(111,151)
Plant in Service	(80,200)
Restoration of UE-88 Net Benefit Write-off	26,828
Net Trojan	175,639

For 17 year Amort Scenario - Full Restoration

Balance @ 4/1/1995	340,162
Boardman Gain	(111,151)
Plant in Service	(80,200)
Restoration of UE-88 Net Benefit Write-off	26,828
Net Trojan	175,639

Trojan Settlement Summary
Based on Actual Balances @ 9/30/00
Amounts in Dollars

			Balance Sheet	
	Item	**Gross Book**	**Tax**	**Net**
1	Abandoned Plant Bal. @ 9/30/00	$ 180,485,809	$ (43,477,921)	$ 137,007,888
2	FASB 109	$ 28,634,202	$ (28,634,202)	$ -
3	Pre-ERTA ITC Flow	$ -	$ (3,349,592)	$ (3,349,592)
4	Post-ERTA ITC Flow	$ -	$ (2,204,085)	$ (2,204,085)
5	Excess Deferred Tax	$ -	$ (2,138,227)	$ (2,138,227)
6	Net Abandoned Plant	$ 209,120,011	$ (79,804,027)	$ 129,315,984
7	SCE	$ (71,800,079)	$ 28,425,651	$ (43,374,428)
8	Merger Benefits	$ (80,415,744)	$ 31,836,593	$ (48,579,151)
9	NEIL refund	$ -	$ -	$ -
10	CRPUD Credit	$ (1,899,583)	$ 752,045	$ (1,147,538)
11	Employee Transfer Credit	$ (1,116,856)	$ 442,163	$ (674,693)
12	Deferred Litigation Credit	$ (4,598,859)	$ 1,820,688	$ (2,778,171)
13	EPRI Credit (New)	$ (2,617,926)	$ 1,036,437	$ (1,581,489)
14	USDOE Fuel Credit	$ (2,524,342)	$ 999,385	$ (1,524,957)
15	USDOE D&D Debit	$ 10,461,145	$ (4,141,559)	$ 6,319,586
16	Burbank Credit	$ (7,383,879)	$ 2,923,278	$ (4,460,601)
17	Balance Sheet After Off-Sets	$ 47,223,888	$ (15,709,346)	$ 31,514,542
18	Remove Post-ERTA ITC	$ -	$ 2,204,085	$ 2,204,085
19	Balance to Collect (Refund)	$ 47,223,888	$ (13,505,261)	$ 33,718,627
	Remaining Balance Collected via:			
20	**Collect New Reg Asset - No "Return on"**	$ 47,399,772	$ (18,765,570)	$ 28,634,202
21	**Residual to Collect (Refund) - Written Off**			$ 5,084,425

FAS 90 Impairment Test (No "return on")
Starting with Pre UE-88 Writeoff Balance

Trojan Unamortized Balance @ 4/1/1995 (Pre UE-88 Writeoff)	$	366,990,485
FAS 71 Portion	$	21,637,002
FAS 90 Portion	$	345,353,483

Discount Rate (Incremental Cost of Debt) 8.0%

17-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization
1995	$ 20,314,911	$ 1,272,765	$ 21,587,676
1996	$ 20,314,911	$ 1,272,765	$ 21,587,676
1997	$ 20,314,911	$ 1,272,765	$ 21,587,676
1998	$ 20,314,911	$ 1,272,765	$ 21,587,676
1999	$ 20,314,911	$ 1,272,765	$ 21,587,676
2000	$ 20,314,911	$ 1,272,765	$ 21,587,676
2001	$ 20,314,911	$ 1,272,765	$ 21,587,676
2002	$ 20,314,911	$ 1,272,765	$ 21,587,676
2003	$ 20,314,911	$ 1,272,765	$ 21,587,676
2004	$ 20,314,911	$ 1,272,765	$ 21,587,676
2005	$ 20,314,911	$ 1,272,765	$ 21,587,676
2006	$ 20,314,911	$ 1,272,765	$ 21,587,676
2007	$ 20,314,911	$ 1,272,765	$ 21,587,676
2008	$ 20,314,911	$ 1,272,765	$ 21,587,676
2009	$ 20,314,911	$ 1,272,765	$ 21,587,676
2010	$ 20,314,911	$ 1,272,765	$ 21,587,676
2011	$ 20,314,911	$ 1,272,765	$ 21,587,676
Total	$ 345,353,483	$ 21,637,002	$ 366,990,485

PV $ 185,305,264

1-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization
1995	$ 345,353,483	$ 21,637,002	$ 366,990,485

PV $ 319,771,744

17 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 345,353,483
PV of FAS 90 Cash Flows	$ 185,305,264
Pre-tax Write-Off	$ 160,048,219

Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 185,305,264
FAS 71 @ 4/1/1995	$ 21,637,002
Total Unamortized balance after Write-Off	$ 206,942,266

1 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 345,353,483
PV of FAS 90 Cash Flows	$ 319,771,744
Pre-tax Write-Off	$ 25,581,739

Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 319,771,744
FAS 71 @ 4/1/1995	$ 21,637,002
Total Unamortized balance after Write-Off	$ 341,408,746

FAS 90 Impairment Test (No "return on")
Starting with Post UE-88 Writeoff Balance

Trojan Unamortized Balance @ 4/1/1995 (Post UE-88 Writeoff)	$ 340,162,435
FAS 71 Portion	$ 17,582,008
FAS 90 Portion	$ 322,580,427

Discount Rate (Incremental Cost of Debt) 8.0%

17-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization
1995	$ 18,975,319	$ 1,034,236	$ 20,009,555
1996	$ 18,975,319	$ 1,034,236	$ 20,009,555
1997	$ 18,975,319	$ 1,034,236	$ 20,009,555
1998	$ 18,975,319	$ 1,034,236	$ 20,009,555
1999	$ 18,975,319	$ 1,034,236	$ 20,009,555
2000	$ 18,975,319	$ 1,034,236	$ 20,009,555
2001	$ 18,975,319	$ 1,034,236	$ 20,009,555
2002	$ 18,975,319	$ 1,034,236	$ 20,009,555
2003	$ 18,975,319	$ 1,034,236	$ 20,009,555
2004	$ 18,975,319	$ 1,034,236	$ 20,009,555
2005	$ 18,975,319	$ 1,034,236	$ 20,009,555
2006	$ 18,975,319	$ 1,034,236	$ 20,009,555
2007	$ 18,975,319	$ 1,034,236	$ 20,009,555
2008	$ 18,975,319	$ 1,034,236	$ 20,009,555
2009	$ 18,975,319	$ 1,034,236	$ 20,009,555
2010	$ 18,975,319	$ 1,034,236	$ 20,009,555
2011	$ 18,975,319	$ 1,034,236	$ 20,009,555
Total	$ 322,580,427	$ 17,582,008	$ 340,162,435

PV $ 173,085,995

1-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization
1995	$ 322,580,427	$ 17,582,008	$ 340,162,435

PV $ 298,685,581

17 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 322,580,427
PV of FAS 90 Cash Flows	$ 173,085,995
Pre-tax Write-Off	$ 149,494,432
Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 173,085,995
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 190,668,003

1 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 322,580,427
PV of FAS 90 Cash Flows	$ 298,685,581
Pre-tax Write-Off	$ 23,894,846
Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 298,685,581
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 316,267,589

FINAL ACCOUNTING JOURNAL ENTRIES FOR ACTION APPROVED IN OPUC ORDER 00-601

As of September 30, 2000

FERC Account	Description	Debit	Credit
	(1)		
182.3	Other Regulatory Assets (Inventory Liquidation)		8,499,232.33
182.2	Unrecoverd Plant Costs (Trojan Plant Costs)		171,986,576.39
186	Deferred Charges (Balance Sheet Simplification Clearing Account)	180,485,808.72	
	To clear balance sheet accounts for Abandoned Plant		
	(2)		
283	Deferred Tax Liabilities (Unrecoverd Plant Costs -Trojan Plant Costs)	43,477,921.00	
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		43,477,921.00
	To clear balance sheet accounts for deferred taxes related to Abandoned Plant		
	(3)		
282	Deferred Tax Liabilities (prior FAS 109 Assets)	28,634,202.00	
283	Deferred Tax Liabilities (prior FAS 109 Assets)	18,765,568.00	
182.3	Other Regulatory Assets (prior FAS 109 Assets)		47,399,770.00
	To reverse regulatory asset for FAS 109 deferred tax accrual for Trojan Plant		
	(4)		
282	Deferred Tax Liabilities (Trojan Excess Deferred Tax)	2,138,227.00	
255	Deferred Investment Tax Credits (Pre-ERTA ITC Flow)	3,349,592.00	
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		5,487,819.00
	To amortize Pre-ERTA ITC and Excess Def Taxes for Trojan plant		
	(5)		
186	Deferred Charges (Balance Sheet Simplification Clearing Account)	10,461,145.00	
182.3	Other Regulatory Assets (USDOE D&D Assessments - Deferred)		10,461,145.00
	To clear balance sheet accounts for USDOE D&D Assessments		
	(6)		
283	Deferred Tax Liabilities (USDOE D&D Assessments - Deferred)	4,141,559.00	
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		4,141,559.00
	To clear balance sheet accounts for deferred taxes related to USDOE D&D Assessments - Deferred		

As of September 30, 2000

FERC Account	Description	Debit	Credit
	(7)		
229	Accum Provision for Rate Refunds (USDOE Spent Nuc Fuel Credit)	2,524,342.44	
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		2,524,342.44
	To clear balance sheet accounts for USDOE Spent Nuc Fuel Credit		
	(8)		
186	Deferred Charges (Balance Sheet Simplification Clearing Account)	999,385.00	
190	Deferred Tax Assets (USDOE Spent Nuc Fuel Credit)		999,385.00
	To clear balance sheet accounts for deferred taxes related to USDOE Spent Nuc Fuel Credit		
	(9)		
254	Other Regulatory Liabilities (SCE Settlement)	71,800,079.03	
254	Other Regulatory Liabilities (Merger obligation)	80,415,743.58	
254	Other Regulatory Liabilities (CRPUD Sale)	3,969,188.50	
229	Accum Provision for Rate Refunds (Employee Transfer Credit)	1,116,855.59	
254	Other Regulatory Liabilities (Deferred Litigation)	4,598,859.05	
229	Accum Provision for Rate Refunds (EPRI Credit)	2,617,925.73	
254	Other Regulatory Liabilities (Burbank Settlement)	7,383,879.15	
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		171,902,530.63
	To clear balance sheet accounts for Regulatory Liabilities and Provision for refund		
	(10)		
186	Deferred Charges (Balance Sheet Simplification Clearing Account)	68,056,212.00	
190	Deferred Tax Asset (Burbank Settlement)		2,923,278.00
190	Deferred Tax Asset (SCE Settlement)		28,425,651.00
190	Deferred Tax Asset (Merger obligation)		31,836,593.00
190	Deferred Tax Asset (CRPUD Sale)		1,571,402.00
190	Deferred Tax Asset (Employee Transfer Credit)		442,163.00
190	Deferred Tax Asset (Deferred Litigation)		1,820,688.00
190	Deferred Tax Asset (EPRI Credit)		1,036,437.00
	To clear balance sheet accounts for deferred taxes related to Regulatory Liabilities and Provision		
	(11)		
186	Deferred Charges (Balance Sheet Simplification Clearing Account)	2,069,605.44	
182.3	Regulatory Assets (payment to WOEC)		2,069,605.44
	To clear balance sheet accounts for payment to WOEC		
	(12)		
283	Deferred Tax Liabilities (payment to WOEC)	819,357.00	
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		819,357.00
	To clear balance sheet accounts for deferred taxes related to payment to WOEC		

FINAL ACCOUNTING JOURNAL ENTRIES FOR ACTION APPROVED IN OPUC ORDER 00-601

As of September 30, 2000

FERC Account	Description	Debit	Credit
	(13)		
182.3	Other Regulatory Assets	47,399,770.00	
283	Deferred Tax Liabilities		18,765,568.00
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		28,634,202.00
	To record new regulatory asset per Section 2.1(b) of Settlement Agreement.		
	(14)		
426.5	Other Deductions	5,084,425.09	
186	Deferred Charges (Balance Sheet Simplification Clearing Account)		5,084,425.09
	To record the write off of the net of balance sheet debits and credits for certain regulatory assets and liabilities and related deferred taxes per Settlement Agreement.		
	(15)		
407.3	Regulatory Debits	2,500,000.00	
254	Other Regulatory Liabilities		2,500,000.00
	To record a regulatory liability per Settlement Agreement		
	(16)		
255	Deferred Investment Tax Credits (Post-ERTA ITC Flow)	2,204,085.00	
420	Investment Tax Credits (Post-ERTA ITC)		2,204,085.00
	To reverse remaining Post-ERTA ITC balance		

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PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1995
(000)

		1995 Per Company Filing (1)	Adjustments (2)	1995 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Operating Revenues					
2	Sales to Consumers	$885,257	$846	$886,103	$47,185	$933,288
3	Other Revenues	8,385	2,410	10,795	0	10,795
4	**Total Operating Revenues**	$893,642	$3,256	$896,898	$47,185	$944,083
5	Operating Expenses and Taxes					
6	Operation & Maintenance					
7	Net Variable Power Costs	$320,346	($13,547)	$306,799	$0	$306,799
8	Fixed Power Costs	71,532	0	71,532	0	71,532
9	Other Oper.& Maint.	147,951	(13,311)	134,640	203	134,843
10	**Total Operation & Maintenance**	$539,829	($26,858)	$512,971	$203	$513,174
11	Depreciation & Amortization	115,170	31,712	146,882	0	146,882
12	Taxes Other than Income	49,471	(892)	48,579	991	49,570
13	Income Taxes	62,438	(481)	61,957	18,139	80,096
14						
15	**Total Operating Expenses and Taxes**	$766,908	$3,481	$770,389	$19,333	$789,722
16	**Utility Operating Income**	**$126,734**	**($225)**	**$126,509**	**$27,848**	**$154,357**
17	Average Rate Base					
18	Utility Plant In Service	$2,651,345	($155,912)	$2,495,433	$0	$2,495,433
19	Accumulated Depreciation	(1,099,656)	72,395	(1,027,261)	0	(1,027,261)
20	Accumulated Deferred Income Taxes	(235,810)	134,771	(101,039)	0	(101,039)
21	Accumulated Deferred Inv. Tax Credit	(54,317)	8,912	(45,405)	0	(45,405)
22	**Net Utility Plant**	$1,261,562	$60,166	$1,321,728	$0	$1,321,728
23	Energy Efficiency	66,801	19,916	86,717	0	86,717
24	Boardman Gain	(99,463)	(18,354)	(117,817)	0	(117,817)
25	Deferred Trojan Investment	291,467	(51,330)	240,137	0	240,137
26	Materials & Supplies - Fuel	14,811	0	14,811	0	14,811
27	- Other	25,973	(5,164)	20,809	0	20,809
28	Working Cash	36,634	92	36,726	880	37,606
29	Misc. Deferred Debits	33,273	0	33,273	0	33,273
30	Misc. Deferred Credits	(15,501)	1,677	(13,824)	0	(13,824)
31	**Total Average Rate Base**	**$1,615,557**	**$7,003**	**$1,622,660**	**$880**	**$1,623,440**
32	**Rate of Return**	7.84%		7.80%		9.51%
33	**Implied Return on Equity**	7.67%		7.83%		11.60%

PORTLAND GENERAL ELECTRIC CO.
General Rate Case Settlement - UE 88
(000)

COST OF CAPITAL - 1995	AMOUNTS	% OF CAPITAL	COST	COST
Long Term Debt	$964,369	49.14%	7.71%	3.79%
Preferred Stock	106,370	5.42%	8.27%	0.45%
Common Equity	891,644	45.44%	11.60%	5.27%
Total	$1,962,383	100.00%		9.51%

13.45

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectibles/OPUC Fee*	0.00430
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97470
State Income Tax @ 6.672%**	0.06503
Federal Taxable Income	0.90967
Federal Income Tax @ 35%	0.31838
ITC	0.00000
Current FIT	0.31838
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38451
Total Revenue Sensitive Costs	0.40981
Utility Operating Income	0.59019
Net-to-Gross Factor	1.69436

* Uncollectible Rate	0.00230
OPUC Fee	0.00200
Total	0.00430

** State Income Tax	
Montana (.0675*.050008)	0.00338
Oregon (.0660*.959764)	0.06334
Total	0.06672

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PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1996
(000)

		1996 Per Company Filing (1)	Adjustments (2)	1996 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Operating Revenues					
2	Sales to Consumers	$910,200	($10,372)	$899,828	$55,550	$955,378
3	Other Revenues	8,719	2,436	11,155	0	11,155
4	**Total Operating Revenues**	$918,919	($7,936)	$910,983	$55,550	$966,533
5	Operating Expenses and Taxes					
6	Operation & Maintenance					
7	Net Variable Power Costs	$378,238	($66,424)	$311,814	$0	$311,814
8	Fixed Power Costs	73,745	0	73,745	0	73,745
9	Other Oper.& Maint.	152,949	(12,865)	140,084	239	140,323
10	**Total Operation & Maintenance**	$604,932	($79,289)	$525,643	$239	$525,882
11	Depreciation & Amortization	124,955	26,846	151,801	0	151,801
12	Taxes Other than Income	49,092	(1,467)	47,625	1,167	48,792
13	Income Taxes	43,748	15,821	59,569	21,354	80,923
14						
15	**Total Operating Expenses and Taxes**	$822,727	($38,089)	$784,638	$22,760	$807,398
16	**Utility Operating Income**	$96,192	$30,153	$126,345	$32,785	$159,130
17	Average Rate Base					
18	Utility Plant in Service	$2,778,739	($162,981)	$2,615,759	$0	$2,615,759
19	Accumulated Depreciation	(1,200,062)	78,752	(1,121,310)	0	(1,121,310)
20	Accumulated Deferred Income Taxes	(241,948)	141,668	(100,280)	0	(100,280)
21	Accumulated Deferred Inv. Tax Credit	(50,164)	8,252	(41,912)	0	(41,912)
22	**Net Utility Plant**	$1,286,565	$65,692	$1,352,257	$0	$1,352,257
23	Energy Efficiency	59,853	47,856	107,709	0	107,709
24	Boardman Gain	(60,904)	(54,916)	(115,820)	0	(115,820)
25	Deferred Trojan Investment	268,921	(44,082)	224,839	0	224,839
26	Materials & Supplies - Fuel	14,810	0	14,810	0	14,810
27	- Other	27,205	(5,827)	21,378	0	21,378
28	Working Cash	39,388	(1,882)	37,506	1,036	38,542
29	Misc. Deferred Debits	27,498	0	27,498	0	27,498
30	Misc. Deferred Credits	(16,196)	2,931	(13,265)	0	(13,265)
31	**Total Average Rate Base**	$1,647,140	$9,772	$1,656,912	$1,036	$1,657,947
32	**e of Return**	5.84%		7.63%		0%
33	**lled Return on Equity**	3.08%		7.36%		60%

PORTLAND GENERAL ELECTRIC CO.
General Rate Case - UE 88
(000)

COST OF CAPITAL - 1996	AMOUNTS	% OF CAPITAL	COST	WEIGHTED COST
Long Term Debt	$1,044,215	48.86%	7.82%	3.82%
Preferred Stock	99,703	4.67%	8.27%	0.39%
Common Equity	993,333	46.47%	11.60%	5.39%
Total	$2,137,251	100.00%		9.60%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectible/OPUC Fee*	0.00430
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97470
State Income Tax @ 6.672%**	0.06503
Federal Taxable Income	0.90967
Federal Income Tax @ 35%	0.31838
ITC	0.00000
Current FIT	0.31838
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38451
Total Revenue Sensitive Costs	0.40981
Utility Operating Income	0.59019
Net-to-Gross Factor	1.69436

* Uncollectible Rate	0.00230
OPUC	0.00200
Total	0.00430

** State Income Tax	
Montana (.0675*.050008)	0.00338
Oregon (.0660*.959764)	0.06334
Total	0.06672

UE 93 Stipulation

Boardman Gain Offset Proposal

	As Filed	As Stipulated	
Item	Pre-Tax	Pre-Tax	After-Tax
Boardman Gain	($117.2)	($117.2)	($72.1)
Power Cost Deferrals UM 529, 594, 692	99.0	51.1	31.5
AMAX	16.7	16.7	10.1
SAVE Acceleration	0.0	29.4	18.1
Subtotal	(1.5)	(20.0)	(12.3)
Unamortized Trojan Investment	1.5	20.0	12.3
Proposed balance at Nov. 8, 1995	$0.0	$0.0	$0.0

FAS 90: Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs

an amendment of FASB Statement No. 71

FAS 90 STATUS

Issued: December 1986

Effective Date: For fiscal years beginning after December 15, 1987 and interim periods within those fiscal years

Affects: Amends FAS 71, paragraphs 9, 10, 15, and 34

Supersedes FAS 71, paragraph 13 and footnote 6

Affected by: Paragraph 9(d) superseded by FAS 92

Paragraphs 14 and 27 amended by FAS 96 and FAS 109

Paragraphs 16 through 25 superseded by FTB 87-2

Other Interpretive Pronouncement: FTB 87-2

Issues Discussed by FASB Emerging Issues Task Force (EITF)

Affects: EITF Topic No. D-5

Interpreted by: No EITF Issues

Related Issues: No EITF Issues

FAS 90 Summary

This Statement amends FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*, for two types of events that recently have occurred in the electric utility industry—abandonments of plants and disallowances of costs of recently completed plants.

This Statement amends Statement 71 to require the future revenue that is expected to result from the regulator's inclusion of the cost of an abandoned plant in allowable costs for rate-making purposes to be reported at its present value when the abandonment becomes probable. If the carrying amount of the abandoned plant exceeds that present value, a loss would be recognized. Statement 71 previously required that asset to be reported at the lesser of the cost of the abandoned plant or the probable gross revenue.

This Statement also amends Statement 71 to require any disallowed costs of a recently completed plant to be recognized as a loss. Statement 71 previously required asset impairments to be recognized but did not specify what constitutes an impairment or provide specific guidance about how impairments should be measured.

Finally, this Statement amends Statement 71 to specify that an allowance for funds used during construction should be capitalized only if its subsequent inclusion in allowable costs for rate-making purposes is probable.

This Statement is effective for fiscal years beginning after December 15, 1987 unless (a) application of the Statement would cause a violation or probable future violation of a restrictive clause in an existing loan indenture or other agreement and (b) the enterprise is actively seeking to obtain modification of that restrictive clause. In that case, this Statement is effective for fiscal years beginning after December 15, 1988.

This Statement applies to the recorded costs of previously abandoned assets, the recorded costs of assets for which future abandonment is probable or becomes probable in the future, previously disallowed plant costs, and disallowances of plant costs that are probable or become probable in the future. Restatement of financial statements for prior fiscal years is encouraged but not required.

INTRODUCTION

1. FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*, was issued in December 1982. Shortly after that Statement was issued, major events in the electric utility industry caused the Board to review the effects of the Statement on the accounting for those events. After considering the application of the Statement, the Board decided to amend Statement 71 to provide more specific guidance for some of those events and to change the accounting for others.

2. This Statement amends Statement 71 to specify accounting for plant abandonments and disallowances of costs of recently completed plants. It also provides guidance for the capitalization of an allowance for funds used during construction (AFUDC).

STANDARDS OF FINANCIAL ACCOUNTING AND REPORTING

Accounting for Abandonments

3. When it becomes probable [1] that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process or plant-in-service. The enterprise shall determine whether recovery of any allowed cost is likely to be provided with (a) full return on investment during the period from the time when abandonment becomes probable to the time when recovery is completed or (b) partial or no return on investment during that period. That determination should focus on the facts and circumstances related to the specific abandonment and

should also consider the past practice and current policies of the applicable regulatory jurisdiction on abandonment situations. Based on that determination, the enterprise shall account for the cost of the abandoned plant as follows:

a. *Full return on investment is likely to be provided.* Any disallowance of all or part of the cost of the abandoned plant that is both *probable* and *reasonably estimable*, as those terms are used in FASB Statement No. 5, *Accounting for Contingencies*, and the related FASB Interpretation No. 14, *Reasonable Estimation of the Amount of a Loss*, shall be recognized as a loss, and the carrying basis of the recorded asset shall be correspondingly reduced. The remainder of the cost of the abandoned plant shall be reported as a separate new asset.

b. *Partial or no return on investment is likely to be provided.* Any disallowance of all or part of the cost of the abandoned plant that is both *probable* and *reasonably estimable*, as those terms are used in Statement 5 and Interpretation 14, shall be recognized as a loss. The present value of the future revenues expected to be provided to recover the allowable cost of that abandoned plant and return on investment, if any, shall be reported as a separate new asset. Any excess of the remainder of the cost of the abandoned plant over that present value also shall be recognized as a loss. The discount rate used to compute the present value shall be the enterprise's incremental borrowing rate, that is, the rate that the enterprise would have to pay to borrow an equivalent amount for a period equal to the expected recovery period. In determining the present value of expected future revenues, the enterprise shall consider such matters as (1) the probable time period before such recovery is expected to begin and (2) the probable time period over which recovery is expected to be provided. If the estimate of either period is a range, the guidance of Interpretation 14 shall be applied to determine the loss to be recognized. Accordingly, the most likely period within that range shall be used to compute the present value. If no period within that range is a better estimate than any other, the present value shall be based on the minimum time period within that range.

4. The recorded amount of the new asset shall be adjusted from time to time as necessary if new information indicates that the estimates used to record the separate new asset have changed. Those estimates include (a) the determination of whether full return on investment will be provided and, if not, the probable time period before recovery is expected to begin and the probable time period over which recovery is expected to be provided and (b) the amount of any probable and reasonably estimable disallowance of recorded costs of the abandoned plant. The amount of the adjustment shall be recognized in income as a loss or gain. Paragraphs 21, 22, and 24 of Appendix A illustrate how this paragraph applies to changes in the estimated time period before recovery begins and the time period over which recovery is expected to be provided. The recorded carrying amount of the new asset shall not be adjusted for changes in the enterprise's incremental borrowing rate.

5. During the period between the date on which the new asset is recognized and the date on which recovery begins, the carrying amount shall be increased by accruing a carrying charge. The rate used to accrue that carrying charge shall be as follows:

a. If full return on investment is likely to be provided, a rate equal to the allowed overall cost of capital in the jurisdiction in which recovery is expected to be provided shall be used.

b. If partial or no return on investment is likely to be provided, the rate that was used to compute the present value shall be used. Paragraphs 20 and 23 and Schedules 1 and 2 of Appendix A illustrate that procedure.

6. During the recovery period, the new asset shall be amortized as follows:

a. If full return on investment is likely to be provided, the asset shall be amortized in the same manner as that used for rate-making purposes.

b. If partial or no return on investment is likely to be provided, the asset shall be amortized in a manner that will produce a constant return on the unamortized investment in the new asset equal to the rate at which the expected revenues were discounted. Paragraph 25 and Schedule 3 of Appendix A illustrate that procedure.

Disallowances of Costs of Recently Completed Plants

7. When it becomes probable that part of the cost of a recently completed plant will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made,2 the estimated amount of the probable disallowance shall be deducted from the reported cost of the plant and recognized as a loss. If part of the cost is explicitly, but indirectly, disallowed (for example, by an explicit disallowance of return on investment on a portion of the plant), an equivalent amount of cost shall be deducted from the reported cost of the plant and recognized as a loss.

Allowance for Funds Used during Construction

8. Paragraph 15 of Statement 71 requires an allowance for funds used during construction, including a designated cost of equity funds, to be capitalized in specified circumstances as part of the acquisition cost of the related asset. That cost shall be capitalized under those circumstances only if its subsequent inclusion in allowable costs for rate-making purposes is probable.

Amendments to Statement 71

9. Statement 71 is amended as follows:

a. Footnote 6 to paragraph 9 is superseded by the following:

[6]The term *probable* is used in this Statement consistent with its use in FASB Statement No. 5, *Accounting for Contingencies*. Statement 5 defines *probable* as an area within a range of the likelihood that a future event or events will occur. That range is from probable to remote, as follows:

Probable. The future event or events are likely to occur.

Reasonably possible. The chance of the future event or events occurring is more than remote but less than likely.

Remote. The chance of the future event or events occurring is slight.

b. The following footnote is added at the end of the first sentence of paragraph 9:

*Costs of abandoned plants shall be accounted for in accordance with paragraphs 3-6 of FASB Statement No. 90, *Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs*.

c. The following footnote is added to the end of paragraph 10:

†Disallowances of costs of recently completed plants, whether direct or indirect, shall be accounted for in accordance with paragraph 7 of Statement 90.

d. Paragraph 13 is superseded by the following:

Appendix B and Statement 90 illustrate the application of the general standards of accounting for the effects of regulation.

e. The following sentence is added preceding the last sentence of paragraph 15:

Those amounts shall be capitalized only if their subsequent inclusion in allowable costs for rate-making purposes is probable.

f. The following footnote is added to the end of the third sentence of paragraph 34:

‡An exception to this general rule is provided for costs of abandoned plants. Paragraphs 16-25 of Statement 90 illustrate accounting for future revenues expected to result from the cost of an abandoned plant with a partial return or no return on investment during the recovery period.

Effective Date and Transition

10. Except as provided in paragraph 13, the provisions of this Statement shall be effective for fiscal years beginning after December 15, 1987 and interim periods within those fiscal years. Earlier application is encouraged. Retroactive application of this Statement in fiscal years for which financial statements have previously been issued is encouraged, in which case the financial statements of all prior periods presented shall be restated. In addition, the financial statements shall, in the year this Statement is first applied, disclose the nature of any restatement and its effect on income before extraordinary items, net income, and related per share amounts for each period presented and on retained earnings at the beginning of the earliest period presented.

11. If financial statements for prior fiscal years are not restated, the effects of applying this Statement to existing situations shall be reported as the cumulative effect of a change in accounting principle, as described in APB Opinion No. 20, *Accounting Changes*, and the nature of the change and the effect of adopting this Statement on income before extraordinary items, net income, and the related per share amounts shall be disclosed.

12. Initial application of this Statement will require the following adjustments to previously recorded assets with corresponding adjustments to reported net income of prior years or to the cumulative effect of an accounting change in the year of the change:

a. Amounts that were recorded in prior years for recoverable costs of abandoned plants shall be adjusted as indicated in paragraph 3. If partial or no return on investment is likely to be provided, the discount rate used to compute the present value shall be the regulated enterprise's incremental borrowing rate at the date on which the abandonment became probable.

b. Disallowed plant costs of the types described in paragraph 7 shall be deducted from the reported cost of the related asset.

13. If application of this Statement would cause a violation or probable future violation of a restrictive

clause in an existing loan indenture or other agreement and the enterprise is actively seeking to obtain modification of that restrictive clause, that enterprise may delay application of this Statement for one additional year. In that case, the enterprise shall disclose, in its financial statements for the first fiscal year beginning after December 15, 1987 and interim periods within that fiscal year, (a) the effects that application of this Statement would have had on assets, retained earnings at the end of that fiscal year or interim period, income before extraordinary items, net income, and related per share amounts, (b) the nature of the violation or probable future violation that would result from application of the Statement, and (c) the steps that the company is taking to eliminate the restrictions. That enterprise shall apply this Statement, as indicated in paragraphs 10-12 above, for fiscal years beginning after December 15, 1988 and interim periods within those fiscal years.

The provisions of this Statement need not be applied to immaterial items.

This Statement was adopted by the affirmative votes of four members of the Financial Accounting Standards Board. Messrs. Brown, Kirk and Northrop dissented.

Messrs. Brown and Northrop dissent to this Statement's provisions concerning accounting for abandonments and disallowances of plant costs. They see no reason to modify the applicability of generally accepted accounting principles to regulated enterprises beyond those departures specifically called for by Statement 71.

Messrs. Brown and Northrop disagree with the requirement to record recoverable costs of abandoned plants at their present value and subsequently to accrue the discount resulting from this present value computation. They would record the costs associated with abandoned plants at the lower of cost or gross recoverable amount (the undiscounted amount of such costs that will be allowed in future rates). They would amortize these costs over the period during which they will be allowed for rate-making purposes. In their view, this cost recovery approach, now specified by Statement, should not be changed because it (1) conforms with accounting for enterprises in general and (2) is consistent with the Board's conclusion not to require recoverable costs of other regulator-created assets, such as storm damage costs, to be recorded at their present value. Further, they believe that recording recoverable costs at their present value results in inappropriate understatement of current period net income and overstatements of net income in subsequent periods.

Messrs. Brown, Kirk and Northrop object to the requirement to recognize disallowances of costs of newly completed operating plants as losses in all cases. In their view, a regulator's disallowance of part of the cost of a fixed asset is an event warranting disclosure but not accounting recognition, except to the extent that the asset has been impaired. They believe that, barring impairment, reflecting a disallowance as a loss inappropriately recognizes reduced future revenues as reductions in current period net income. This results in overstatement of net income in subsequent periods.

Members of the Financial Accounting Standards Board:

Donald J. Kirk, *Chairman*

Victor H. Brown

Raymond C. Lauver

David Mosso

C. Arthur Northrop

Robert J. Swieringa

Arthur R. Wyatt

Appendix A: EXAMPLES OF APPLICATION OF THIS STATEMENT TO SPECIFIC SITUATIONS

14. This appendix provides guidance for application of this Statement to some specific situations. The guidance does not address all possible applications of this Statement. All the examples assume that the enterprise meets the criteria in paragraph 5 of Statement 71 for the application of Statement 71 by the enterprise. Cases similar to those illustrated in this appendix may involve income tax effects that could accrue to the utility in question. Some of those tax effects may be recognized currently under the applicable authoritative literature (presently APB Opinion No. 11, *Accounting for Income Taxes*); others may not be recognized currently. Under Opinion 11, the tax effects of timing differences are measured by the differential between income taxes computed with and without inclusion of the transaction creating the difference between taxable income and pretax accounting income. For simplicity, the examples base the income tax effects on a 34 percent tax rate and assume that those effects may be recognized.

15. Specific situations discussed in this appendix are:

	Paragraph Numbers
Accounting for an abandonment..	16-25
Accounting for a disallowance of plant cost..	26-27
Accounting for a disallowance of plant cost resulting from a "cost cap".........	28-31
Accounting for an explicit, but indirect, disallowance....................................	32-34

Accounting for an Abandonment

16. Assume that Utility A operates solely in a single-state jurisdiction that, in the past, has permitted recovery of amounts prudently invested in abandoned plants over an extended period of time without a return on unrecovered investment during the recovery period. Utility A decides to abandon a plant that has been under construction for some time. Although the possibility of abandoning the plant has been under consideration, abandonment was not considered probable before the actual decision was made. The recorded cost of the plant is $728 million; and the company estimates that it will incur additional contract cancellation penalties of approximately $22.5 million, which will be paid in approximately 6 months. Utility A's incremental borrowing rate at the date of the decision to abandon the plant is 14 percent, compounded monthly.

17. In view of the accumulated cost of the abandoned plant, Utility A believes that it is probable that recovery of cost without return on investment during the recovery period will be granted over a period that will not be less than 5 years nor more than 10 years, but it has no basis for estimating the exact time period that will be selected by the regulator. In view of the rate-making process in Utility B's jurisdiction, it will take approximately 18 months to obtain a rate order covering the abandoned plant.

18. For income tax purposes, the abandoned plant has a basis of $500 million, including the contract cancellation penalties of $22.5 million. Utility A will deduct the cost of the abandoned plant as a loss on its income tax return in the year of the abandonment and will receive a tax benefit of 34 percent. All of the benefit of that loss will be recognized in the current year, partially through a reduction of current taxable income and carryback to prior years, the balance through offset of existing deferred taxes that will reverse during the carryforward period. Existing deferred taxes on timing differences relating to the abandoned plant total $35 million. For regulatory purposes, the tax benefit of the abandonment will be reflected as recovery of part of the cost of the abandoned plant.

19. When the abandonment becomes probable (in this case, at the date of the decision to abandon), Utility A would remove the plant from construction work-in-process. Any disallowance of the recorded cost that is probable and can be reasonably estimated would be recorded as a loss. This example assumes that no disallowance of recorded cost is anticipated. Utility A would record a separate new asset, representing the future revenues expected to result from the regulator's treatment of the cost of the abandoned plant, at the present value of those expected future revenues. The computation of the amount to be recovered would be as follows:

Recorded cost of abandoned plant		$728,
Cancellation charges payable		22,50
Total		750,5
Less reduction of cost in an amount equal to the amounts designated by the regulator for current recovery:		
Current tax benefit of abandonment	$170,000,000	
Deferred taxes reversed	35,000,000	205,0
Net amount to be recovered in future rates		$545,

The probable future revenues would be estimated at $9,091,667 per month for 5 years (based on an assumed straight-line recovery over the 5-year minimum period within the range), and those cash flows would be estimated to begin in 19 months. The computation of the amount to be recorded for the new asset and of the loss resulting from the abandonment would be as follows:

Present value of $9,091,667 per month at 14% for 60 months, starting at the end of the 19th month (amount to be recorded as new asset)		$317,
Cost of abandoned plant:		
Net amount to be recovered in future rates for regulatory purposes (per table above)	$545,500,000	
Discount to reduce cancellation charges to present value ($22,500,000 discounted at 14% for 6 months)	(1,512,637)	543,
Loss to be recognized at time of abandonment		226,9
Deferred tax benefit at 34%		77,
Net loss to be recognized at time of decision to abandon the plant		$149,

The deferred tax benefit of the recovery would reverse in relation to the earnings on the unamortized asset. The deferred tax on the imputed interest on the cancellation charges would reverse as interest expense is accrued.

20. Pending receipt of a rate order, Utility A would accrue carrying charges on the recorded asset at a 14 percent annual rate. Schedule 1 shows that computation.

Schedule 1

Utility A

Accrual of Carrying Charges on Asset Resulting from Abandoned Plant

Month	Recorded Amount Beginning of Month	Carrying Charges Accrued *	Recorded Amount End of Month
1	$317,107,016	$3,699,582	$320,806,598
2	320,806,598	3,742,743	324,549,341
3	324,549,341	3,786,409	328,335,750
4	328,335,750	3,830,584	332,166,334
5	332,166,334	3,875,274	336,041,608
6	336,041,608	3,920,486	339,962,094
7	339,962,094	3,966,224	343,928,318
8	343,928,318	4,012,497	347,940,815
9	347,940,815	4,059,310	352,000,125
10	352,000,125	4,106,668	356,106,793
11	356,106,793	4,154,579	360,261,372
12	360,261,372	4,203,049	364,464,421

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*As carrying charges are accrued, deferred income tax benefits would be reversed and income tax expense recognized in accordance with Opinion 11.

21. Assume that at the end of the 12th month Utility A determines that it is now probable, based on discussions with the regulator, that recovery of cost without return on investment will be granted over a period that will not be less than 7 years nor more than 15 years, but it still has no basis for estimating the exact time period that will be selected by the regulator. Utility A also estimates that it will take approximately another 12 months (that is, 24 months after the date of the decision to abandon rather than the 18 months previously assumed) to obtain a rate order.

22. When new evidence makes it possible to refine a previous estimate, Utility A would adjust the recorded amount of the asset to reflect its revised estimate. The probable future revenues now would be estimated at $6,494,048 per month for 7 years (based on an assumed straight-line recovery over the 7-year minimum period within the range), and those cash flows would be estimated to begin 25 months after the date of the decision to abandon. The computation of the adjustment to the carrying amount of the asset that results from the new estimate would be as follows:

Present value of $6,494,048 per month at 14% for 84 months, starting at the end of the 25th month, which is 13 months in the future (adjusted carrying	$301,506,272

amount of asset)	
Carrying amount of asset at end of 12th month (Schedule 1)	364,464,421
Pretax loss to be recognized at end of 12th month	62,958,149
Deferred tax benefit of loss at 34%	21,405,771
Net loss to be recognized at end of 12th month	$ 41,552,378

The discount rate would not be adjusted to reflect Utility A's current incremental borrowing rate. That new rate reflects current conditions rather than the conditions that prevailed at the time of the decision to abandon.

23. Pending receipt of a rate order, Utility A would continue to accrue carrying charges on the adjusted recorded asset at a 14 percent annual rate. Schedule 2 shows that revised computation.

Schedule 2

Utility A

Accrual of Carrying Charges on Asset Resulting from Abandoned Plant Revised to Reflect a Change in Estimate

Month	Recorded Amount Beginning of Month	Carrying Charges Accrued *	Recorded Amount End of Month
13	$301,506,272	$3,517,573	$305,023,845
14	305,023,845	3,558,612	308,582,457
15	308,582,457	3,600,128	312,182,585
16	312,182,585	3,642,131	315,824,716
17	315,824,716	3,684,621	319,509,337
18	319,509,337	3,727,609	323,236,946
19	323,236,946	3,771,098	327,008,044
20	327,008,044	3,815,094	330,823,138
21	330,823,138	3,859,603	334,682,741
22	334,682,741	3,904,632	338,587,373
23	338,587,373	3,950,186	342,537,559
24	342,537,559	3,996,271	346,533,830

*As carrying charges are accrued, deferred income tax benefits would be reversed and income tax expense recognized in accordance with Opinion 11.

24. Assume that the rate order is received at the end of the 24th month and specifies a recovery period of 8 years; the resulting revenues will start approximately 1 month after the rate order is received. The probable future revenues now would be estimated at $5,682,292 per month for 8 years (based on the regulator's decision to allow straight-line recovery over an 8-year period), and those cash flows would be estimated to begin 25 months after the abandonment occurred (1 month after the rate order is received). Utility A would reflect that change by recognizing an additional loss, as follows:

Present value of $5,682,292 per month at 14% for 96 months (adjusted

carrying amount of asset)	$327,104,260
Carrying amount of asset at end of 24th month (Schedule 2)	346,533,830
Pretax loss to be recognized at time of rate order	19,429,570
Deferred tax benefit of loss at 34%	6,606,054
Net loss to be recognized at time of rate order	$ 12,823,516

The discount rate would not be adjusted to reflect Utility A's current incremental borrowing rate. That new rate reflects current conditions rather than the conditions that prevailed at the time of the abandonment.

♦25. As recovery occurs, the recorded asset would be amortized so as to reflect earnings on the unamortized asset at the 14 percent rate used to determine the present value of the asset. Schedule 3 shows the details of that computation.

Schedule 3

Utility A

Computation of Amortization of Asset Resulting from Abandoned Plant

	(1)	(2)	(3)	(4)	(5)
Month	**Unamortized Balance Beg. of Month**	**Return * at 14.00%**	**Revenues**	**Amortization of Cost (Col 3 – Col 2)**	**Unamortized Balance End of Month** (Col 1 – Col 4)
25	$327,104,260	$3,816,217	$5,682,292	$1,866,075	$325,238,185
26	325,238,185	3,794,445	5,682,292	1,887,847	323,350,338
27	323,350,338	3,772,421	5,682,292	1,909,871	321,440,467
28	321,440,467	3,750,139	5,682,292	1,932,153	319,508,314
29	319,508,314	3,727,597	5,682,292	1,954,695	317,553,619
30	317,553,619	3,704,792	5,682,292	1,977,500	315,576,119
31	315,576,119	3,681,721	5,682,292	2,000,571	313,575,548
32	313,575,548	3,658,382	5,682,292	2,023,910	311,551,638
33	311,551,638	3,634,769	5,682,292	2,047,523	309,504,115
34	309,504,115	3,610,881	5,682,292	2,071,411	307,432,704
35	307,432,704	3,586,715	5,682,292	2,095,577	305,337,127
.	.	.	.	.	.
.	.	.	.	.	.
.	.	.	.	.	.
.	.	.	.	.	.
110	58,342,320	680,661	5,682,292	5,001,631	53,340,689
111	53,340,689	622,308	5,682,292	5,059,984	48,280,705
112	48,280,705	563,275	5,682,292	5,119,017	43,161,688
113	43,161,688	503,553	5,682,292	5,178,739	37,982,949
114	37,982,949	443,134	5,682,292	5,239,158	32,743,791
115	32,743,791	382,011	5,682,292	5,300,281	27,443,510
116	27,443,510	320,174	5,682,292	5,362,118	22,081,392
117	22,081,392	257,617	5,682,292	5,424,675	16,656,717
118	16,656,717	194,328	5,682,292	5,487,964	11,168,753

119	11,168,753	130,302	5,682,292	5,551,990	5,616,763
120	5,616,763	65,529	5,682,292	5,616,763	0

*As earnings on the unamortized asset are recognized, deferred income tax benefits would be reversed and income tax expense recognized in accordance with Opinion 11.

Accounting for a Disallowance of Plant Cost

26. Assume that Utility B operates in two state jurisdictions. After an extensive "prudence investigation," the regulator in one of those state jurisdictions disallows $865 million of the $3.6 billion total cost of Utility B's recently completed nuclear generating plant. That state jurisdiction represents approximately 50 percent of Utility B's operations, and approximately 50 percent of the output of the recently completed plant is expected to be used in that state. The tax basis of the plant is $2.4 billion. The regulator indicates that the tax benefit from a ratable portion of depreciation will be given to the shareholders as a result of the disallowance. After consultation with counsel, Utility B decides that it should not appeal the regulator's disallowance. The regulator in Utility B's other state jurisdiction has not participated in the "prudence investigation," and there is no indication that a similar disallowance is likely in that jurisdiction.

27. Utility B should recognize the effective disallowance as a loss. Because only 50 percent of the plant's cost will be recoverable from customers in the state, the effective disallowance is 50 percent of the amount disallowed, or $432.5 million. The disallowance should be recognized when the disallowance is probable and the amount of the disallowance can be reasonably estimated, and those conditions are met in this case. The tax benefit of the loss will be realized as future depreciation is taken for income tax purposes. Since the tax benefit of the plant is based on $2.4 billion and the cost of the plant prior to the disallowance is $3.6 billion, only two-thirds of the loss is available for tax benefit. A deferred tax benefit, based on two-thirds of the loss, can be recognized when the loss is recognized providing that benefit meets the criteria of Opinion 11 for recognition.

Accounting for a Disallowance of Plant Cost Resulting from a "Cost Cap"

28. Assume that Utility C, which operates solely in one state jurisdiction, is constructing a new electric generating plant. Completion is expected to take approximately one year. The cost of the plant, which was originally expected to be $1.25 billion, is now estimated to be as follows:

Costs capitalized to date	$2,700,000,000
AFUDC on above for 1 year at 11.25%	303,750,000
Remaining labor, materials, etc., to complete, expected to be spent ratably over the year	469,822,500
AFUDC on above for 1/2 year at 11.25%	26,427,500
Total estimated cost at completion	$3,500,000,000

Various parties have charged that certain cost increases were a result of imprudent management of the construction.

29. To avoid the cost and time delay that would be involved in a full-scale "prudence investigation" of the construction of the plant, Utility C and its regulator agree that the total cost of the plant that will be allowable in determining depreciation and that will be allowed in Utility C's rate base will be $3.4 billion. If the eventual cost of the plant exceeds that "cap," a ratable portion of the tax benefit of

depreciation will accrue to the benefit of the shareholders. For tax purposes, the plant is expected to have a net depreciable basis of $2.0 billion.

30. The loss that results from the disallowance inherent in the "cost cap" would be computed as follows:

Total estimated cost at completion	$3,500,000,000
Maximum allowable cost	3,400,000,000
Difference	$ 100,000,000
Loss to be recognized (present value of difference at 11.25% AFUDC rate, based on 1 year to complete)	$ 89,887,600
Deferred tax benefit of loss (2.0/3.5 × $100,000,000 × 34%)	19,428,600
Net loss to be recognized when "cost cap" is agreed to	$ 70,459,000

After the loss is recognized, AFUDC would continue to be recorded based on the remaining recorded costs. Subsequently, if additional increases in the cost of the plant become probable and those costs are not allowable under the agreed "cost cap," those increases would also be recognized as losses from disallowances when they become probable.

31. If the regulator ordered a "cost cap" that Utility C did not agree to, Utility C would have to assess whether the criteria of Statement 5 for loss recognition are met. If those criteria are met, the accounting would be as indicated above. Otherwise, no loss would be recognized until that loss was probable and could be reasonably estimated. Because of the possible disallowance inherent in the "cost cap," it may no longer be probable that some amount of AFUDC will be included in allowable costs in the future, and that amount may be reasonably estimable. In that case, that amount of AFUDC would not be capitalized.

Accounting for an Explicit, but Indirect, Disallowance

32. Assume that Utility D operates solely in a single-state jurisdiction. On January 1, 19X1, Utility D's new electric generating plant becomes operational. The cost of that plant is $1 billion.

33. Utility D's regulator concludes that part of the cost of the recently completed plant was imprudently incurred. However, rather than disallow the specific costs that were imprudent, the regulator instead excludes 10 percent ($100 million) of the plant from the rate base, thereby providing no return on investment on that portion of the plant. The regulator does not intend any part of the tax benefit of depreciation to accrue to the benefit of Utility D's shareholders. The regulator indicates that the exclusion of 10 percent of the plant's cost from the rate base is intended to be permanent. The utility concludes that it will not appeal the disallowance after considering the likely outcome of an appeal.

34. Utility D should record the indirect disallowance as a loss and should estimate the amount of that loss using the best available information. If the regulator specifies the amount of cost that was imprudent, that amount may be the best estimate of the loss. Otherwise, Utility D would have to estimate the future cash flows that have been disallowed as a result of the order and determine the effective disallowance by computing the present value of those disallowed future cash flows. Since both the disallowed future cash flows and the appropriate discount rate to compute the present value would be estimates, those estimates should be calculated on a consistent basis. Accordingly, if the future cash flows are estimated based on the current weighted-average overall cost of Utility D's capital, that weighted-average overall cost of capital should also be used as the discount rate. The loss has no tax benefit to Utility D.

Appendix B: BASIS FOR CONCLUSIONS

Introduction

35. This appendix summarizes considerations that were deemed significant by members of the Board in reaching the conclusions in this Statement. It includes reasons for accepting certain views and rejecting others. Individual Board members gave greater weight to some factors than to others.

General Considerations

36. Many letters received as the Board was developing the conclusions in this Statement objected to the Board's conclusions about accounting for abandonments and disallowances of costs of recently completed plants on the basis that those decisions departed from the historical cost model of accounting for enterprises generally. The Board provided its view of the current accounting model in paragraphs 66-70 of FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises*. Paragraph 66 acknowledges that the current model is not a pure "historical cost" model, as follows:

> Items currently reported in financial statements are measured by different attributes, depending on the nature of the item and the relevance and reliability of the attribute measured. The Board expects the use of different attributes to continue.

37. The Board also noted that much of the accounting specified by Statement 71 is itself a departure from the accounting framework applied by nonregulated enterprises generally. That Statement recognizes that rate actions of a regulator can have economic effects and requires certain items that would be charged to expense by nonregulated enterprises to be capitalized by regulated enterprises solely because the regulator's rate actions can provide reasonable assurance of future revenue.

38. The accounting set forth in Statement 71 requires certain regulated enterprises to recognize probable increases in future revenues due to a regulator's actions as assets by capitalizing incurred costs that would otherwise be charged to expense. The Board believes those regulated enterprises should also recognize probable decreases in future revenues due to a regulator's actions as reductions of assets. General purpose financial statements that recognize asset enhancements but not asset decrements would lack representational faithfulness—a critical qualitative characteristic if financial statements are to be reliable. After reviewing the frequency and magnitude of recent plant abandonments and disallowances of plant costs in the electric utility industry, the Board concluded that it should require the resulting probable decreases in future revenues to be recognized as reductions in assets if financial statements are to be representationally faithful.

39. The Board also believes that the accounting for plant abandonments required by this Statement is consistent with the accounting followed by companies in general for monetary assets under APB Opinion No. 21, *Interest on Receivables and Payables*. Whatever asset remains after a utility plant is abandoned is essentially monetary in nature.

40. Many respondents to the Exposure Draft, *Regulated Enterprises—Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs*, urged the Board not to adopt some of the provisions in this Statement because they would reduce some companies' retained earnings to the extent that

payment of dividends, future financing on favorable terms, or both would be precluded. When a company incurs a loss, significant consequences may occur, and the Board is aware that some of the effects of the issues addressed in this Statement are major. The Board believes that those consequences result from the event that is being accounted for, not from the accounting itself. The Board believes that accounting should reflect major adverse occurrences that affect an enterprise even though the consequences of those major adverse occurrences may be significant.

41. Many respondents also urged the Board not to adopt certain provisions of this Statement because the regulated rates might decrease as a result of the accounting requirements. Others indicated that the regulated rates would increase if the accounting specified by this Statement were required. The Board believes that regulators will provide whatever rates they believe are justified; general-purpose financial reporting should not be designed to encourage or to discourage specific actions of regulators, and regulators can be expected to understand accounting that reflects the effects of their actions.

Accounting for Abandonments

42. Historically, utilities have usually abandoned plants in early stages of construction, rather than after incurring major construction costs. Prior to Statement 71, most regulated enterprises accounted for the costs of abandoned plants on a cost recovery basis; that is, no loss was recorded if revenues promised by a regulator were expected to recover the recorded costs. Statement 71 did not change that practice.

43. Recently, abandonments of plants under construction have become more common, and some utilities have abandoned plants during the later stages of construction. In many cases, the cost of abandoned plants is much greater than in the past.

44. Many respondents to the Exposure Draft indicated that the essential nature of the asset does not change when a plant is abandoned. In their view, cost-based regulation treats all assets the same; a plant under construction and an abandoned plant are both accumulated costs that will be recovered through revenues. The Board does not agree with that view and has concluded that an abandonment changes the nature of the asset. A plant under construction is expected to produce utility services that have value. An abandoned plant can produce no services. Any value that results from the abandoned plant is limited to the revenues that will be furnished through the sales of services provided by other plants.

45. Other respondents to the Exposure Draft urged the Board not to require loss recognition until the loss is probable. That is the basis for loss recognition that is provided by one of the criteria of Statement 5. The Board agrees that loss recognition should not occur until the loss is probable and reasonably estimable, consistent with Statement 5. However, some of those respondents equated *probable* with *certain*. The Board notes that the term *probable* is defined in Statement 5 and is used in the same sense in this Statement. That definition is not synonymous with *certain*, a term that connotes a much higher level of assurance than *probable*.

46. Regulators in many jurisdictions have provided recovery of the cost of abandoned plants without return on investment during the recovery period. That procedure has been described as a means of sharing the loss between customers and shareholders. A cost-recovery approach for accounting for abandonments was based on the view that the regulator was disallowing future earnings, rather than disallowing a portion of the cost of the abandoned plant. In reconsidering that issue in the context of today's environment, the Board concluded that a cost-recovery approach, in effect, delays recognition of losses that are known to have been incurred. Although that approach might have little significance when applied to relatively immaterial items, the significance of the amounts involved in recent cases indicates

that recognition of losses resulting from abandonments should not be delayed beyond the date when they are probable and reasonably estimable.

47. The Board also concluded that the future revenue that will result from inclusion of the cost of an abandoned plant in allowable costs for rate-making purposes is essentially a monetary asset. In the Board's view, an abandoned plant should be written off when abandonment is probable. Unless it is probable that the cost of an abandoned plant will be entirely disallowed by the regulator, a new asset that is essentially a monetary asset should be recognized. That asset most closely resembles a long-term receivable that is recognized on the basis of (a) its cost, if the stated interest rate is reasonable, or (b) its present value, if the interest rate is not stated or if the stated rate is unreasonable. The Board believes that a similar measurement basis is appropriate for expected future revenue that will result from a regulator's treatment of the cost of an abandoned plant.

48. In the Exposure Draft, the Board proposed that the overall rate of return allowed in the regulated enterprise's last rate case in the jurisdiction in which recovery is expected to be received be used to measure the present value of the future revenue that will result from an abandoned plant. Respondents to the Exposure Draft pointed out that the actual disallowance is the overall rate of return in the future rate cases covering the period during which recovery will occur. That rate is not known at the time of the abandonment. The Board agreed that a surrogate rate should be used to compute the present value of the remaining future revenues, and it decided to require the enterprise to use its incremental borrowing rate at the date the abandonment becomes probable.

49. Some respondents suggested that the interest rate used should be changed whenever the allowed overall rate of return changes during the recovery period. The Board views that approach as a means of maintaining the asset in question at its fair value. Fair value often is used in accounting to measure a newly acquired asset when that fair value is more clearly evident than the value of the asset given up. However, with the exception of certain assets that are readily marketable, the present accounting model does not adjust the carrying basis of an existing asset when the fair value of that asset changes.

50. Some respondents to the Exposure Draft indicated that the rate used to value an abandonment should be a net-of-tax rate. Other respondents asked that the Board address the tax effects of the proposed accounting for abandonments. APB Opinion No. 11, *Accounting for Income Taxes*, does not permit accounting for items with tax effects on a net-of-tax basis. Rather, deferred income taxes are provided for timing differences when they occur, and those deferred taxes are reversed when the related timing differences reverse. Opinion 11 applies to taxable enterprises that apply Statement 71 except in the limited circumstances outlined in paragraph 18 of Statement 71. Accordingly, the loss recognized to reduce the asset resulting from an abandonment to its present value and the subsequent profit that results comprise a timing difference. The tax effects of that timing difference would be recognized when the timing difference originates if appropriate under the provisions of Opinion 11.

51. The Board concluded that accruing a carrying charge on, or recognizing accretion of, the present value of the expected future revenue related to an abandonment is appropriate for two reasons. First, the basis used to record that asset recognizes the effect of the regulator's disallowance of future return on investment as a loss in the period in which the loss becomes probable and the amount can be reasonably estimated. The disallowance that already has been recognized should not reduce the reported level of return on investment in later years, and accrual of a carrying charge has the effect of maintaining the level of return on investment similar to what it would have been if there had been no disallowance. Second, the nature of the resulting asset is similar to a long-term receivable, even though Board members acknowledge that it lacks some of the characteristics of a receivable. Accordingly, they concluded that (a) the subsequent reporting should be consistent with that afforded a long-term

receivable and (b) accrual of a carrying charge is consistent with accounting for a long-term receivable initially recognized at its present value.

52. A number of respondents to the Exposure Draft objected to the requirement that the amount recorded for the probable future revenue that would result from an abandonment be adjusted when a rate order is received. They indicated that the real process of regulation in some jurisdictions occurs in the courts. The Board viewed the rate order as the confirming event, permitting an estimate of the loss to be refined at that time, and it believes that will usually be the case. However, the Board agrees that a loss should not be recognized unless it is probable that a loss has occurred and the amount can be reasonably estimated. If those criteria are not met at the time of an initial rate order, the loss should not be recognized at that time.

53. The Board considered adopting a requirement that all assets representing solely the probable future revenue resulting from a regulator's actions be recorded at the present value of the future cash flows and decided not to adopt such a requirement at this time. Some Board members noted that the requirement of Statement 71 to recognize those other assets on a cost-recovery basis, which was a continuation of prior practice, does not seem to have caused major problems in practice. Other Board members noted that the rate treatment anticipated during construction, prior to abandonment of the asset under construction, was full recovery of both cost and return on investment, whereas the cost of repairing storm damage, which is sometimes afforded recovery over a period of time without return on investment, represents a cash outlay usually made with the anticipation of that rate treatment. Thus, if the Board were to conclude that recording that asset at the amount of the consideration paid is not appropriate, that conclusion would be based on considerations somewhat different from those that the Board applied to abandonments.

Disallowances of Costs of Recently Completed Plants

54. Paragraph 10 of Statement 71 addresses disallowances by a regulator. That paragraph indicates that when a disallowance occurs, "the carrying amount of any related asset shall be reduced to the extent that the asset has been impaired. Whether the asset has been impaired shall be judged the same as for enterprises in general."

55. Recently, several disallowances of major amounts of cost on recently completed plants have been well publicized. The AICPA Issues Paper, "Application of Concepts in FASB Statement of Financial Accounting Standards No. 71 to Emerging Issues in the Public Utility Industry," concludes that "the measure of whether an asset has been impaired [when part of the cost of that asset is disallowed for rate-making purposes] is whether net cash inflows (revenues less applicable expenses) are sufficient to cover the cost of the asset. In measuring expenses, interest applicable to the unit should be included, but equity return would not be included."

56. The Board concluded that the view described in the AICPA Issues Paper, which appears to describe some, but not all, of existing practice, is a narrower interpretation of an "impairment," as referred to in paragraph 10 of Statement 71, than is appropriate for the events in question. The Board believes that an impairment evaluation includes the estimation of losses in value that become determinable as a result of an identifiable event, and it concluded that a regulator's disallowance of part of the cost of a recently completed plant creates an impairment that warrants recognition.

57. Some Board members also believe that the stated reason for certain recent disallowances of plant costs—that the costs were not productive or were not necessary for the completion of the plant—indicates that those costs should not be included in the carrying amount of the related plant.

Nonregulated enterprises do not continue to carry identified nonproductive costs as part of the cost of their fixed assets, and regulated enterprises also should not do so.

58. Many respondents to the Exposure Draft objected to what they considered to be a unique impairment evaluation. The Board believes that the event in question, disallowance of part of the cost of an operating plant by a regulator, is itself unique. Other enterprises do not have disallowances of their plant costs resulting from actions of a regulator.

59. The Board believes that the credibility of financial reporting in general would be diminished by the failure to recognize a diminution in value and a corresponding loss that is generally agreed to have occurred. When a regulator disallows a significant part of the cost of a recently completed plant, financial statements that do not report that disallowance as a loss reflect adversely on the representational faithfulness of those financial statements and of financial statements generally. Accordingly, the Board decided to amend Statement 71 to require loss recognition for such a disallowance.

60. Some respondents to the Exposure Draft requested that the Board address "excess capacity" disallowances. Those disallowances relate to part of the cost of service of a recently completed plant and are based on a finding that the utility's reserve capacity exceeds an amount deemed to be reasonable. If an "excess capacity" disallowance is ordered by a regulator *without* a specific finding that the enterprise should not have constructed that capacity or should have delayed the construction of that capacity, the rate order raises questions about whether the enterprise meets the criteria for application of Statement 71, in that it is not being regulated based on its own cost of service. However, because such a rate order itself is neither a direct disallowance nor an explicit, but indirect, disallowance of part of the cost of the plant, this Statement does not specify the accounting for it. If an "excess capacity" disallowance is ordered by a regulator *with* a specific finding that the enterprise should not have constructed that capacity or should have delayed the construction of that capacity, the rate order may be an explicit, but indirect, disallowance of part of the cost of the plant, and the enterprise should account for the substance of that order as set forth in paragraph 7 of this Statement.

61. In a few recent cases, a regulator has included a recently completed plant in rates based on the assumed cost of another plant rather than based on the cost of the plant that exists. In those cases, the enterprise is not being regulated based on its own cost, and the criteria of application of Statement 71 do not appear to be met. If the rate order is based on a finding that, based on factors that were known during the construction, the utility should not have constructed the plant that it did construct, the order may be an explicit, but indirect, disallowance, and it should be accounted for as set forth in paragraph 7 of this Statement. Otherwise, unless the order is being appealed, the enterprise should consider discontinuing application of Statement 71.

62. A number of respondents indicated that it would often be impossible to determine whether an indirect disallowance had been made. They noted that regulators have considerable discretion in selecting a rate that represents a fair return on equity investment, and that specific matters included in a settlement agreement might not be apparent. The Board intends that explicit, but indirect, disallowances be reported as disallowances; it does not intend to require that an enterprise determine whether the terms of a settlement agreement or rate order contained a hidden, indirect disallowance. Accordingly, paragraph 7 of this Statement was modified to indicate the Board's intent.

63. The Board considered making a more sweeping amendment of Statement 71, to require loss recognition for all cost disallowances by a regulator, whether related to a recently completed plant or otherwise. For example, regulators in some jurisdictions disallow costs of acquired companies in excess of the acquired company's book value and a variety of other types of costs. After consideration, the

Board decided to limit this Statement to the relatively narrow issues that caused the Board to add a project on regulated enterprises to its agenda.

Criteria for Capitalization of AFUDC

64. Paragraph 15 of Statement 71 requires an allowance for funds used during construction, including an allowance for equity funds, to be capitalized in lieu of capitalizing interest in accordance with FASB Statement No. 34, *Capitalization of Interest Cost*, if certain criteria are met. The AICPA Issues Paper cited a need for guidance on whether AFUDC should be capitalized in a number of different situations.

65. After considering the cases in which capitalization of AFUDC is controversial, the Board concluded that AFUDC should be capitalized only if subsequent inclusion of that AFUDC in plant cost for rate-making purposes is probable. That conclusion was based on paragraph 15 of Statement 71, which is derived from the general standards in paragraphs 9-12 of that Statement. Under those general standards, a cost may not be capitalized unless it is probable that the cost will be included in allowable cost in the future, and the Board concluded that the same criteria should apply to capitalization of AFUDC.

66. Some respondents to the Exposure Draft indicated that AFUDC is a cost, and it warrants capitalization whenever the general criteria of Statement 34, that interest cost is being incurred and construction is in progress, are met. The Board disagreed with this view of AFUDC. Statement 71 concluded that, if specific criteria in paragraph 15 are met, the AFUDC that will be the basis for future rates should be capitalized instead of interest computed in accordance with Statement 34. As noted above, that provision of Statement 71 was derived from the general standards in paragraphs 9-12 of that Statement. Those general standards require that inclusion of an amount in allowable cost in the future be probable for that amount to be capitalized. The Board believes that the intent of Statement 71, in accepting the amount of AFUDC that will be the basis for future rates instead of the usual capitalization of interest, was not solely to accept a surrogate computation, but also to accept a computation that was a better indicator of future cash flows for enterprises that meet both the criteria for application of Statement 71 and the criteria of paragraph 15 of the Statement for capitalization of AFUDC. The Board concluded that allowing capitalization of amounts for which future inclusion in allowable cost for rate-making purposes was not probable would make the resulting capitalized amounts poorer indicators of the future cash flows expected to result from utility plants. Accordingly, the Board concluded that if inclusion of that AFUDC in the cost that will become the basis for future rates is not probable, the enterprise should not capitalize it. The Board also concluded that, if the specific criteria in paragraph 15 of Statement 71 are met but AFUDC is not capitalized because its inclusion in the cost that will become the basis for future rates is not probable, the regulated enterprise may not alternatively capitalize interest cost in accordance with Statement 34.

67. The Board believes that the criteria for capitalization of AFUDC are particularly relevant to two situations that have occurred in practice. In the first situation, completion of a plant under construction is reasonably possible but no longer probable, and the regulator in the governing jurisdiction routinely disallows accumulated AFUDC on abandoned plants. In that situation, the criteria required to write off previously recognized AFUDC are not met since disallowance is not probable; thus, previously capitalized AFUDC should not be written off. However, because inclusion of AFUDC in the cost allowed for future rates is no longer probable, further capitalization of AFUDC is not warranted.

68. In the second situation, a prudence investigation is in process or has taken place, and a disallowance of cost (including subsequent AFUDC on those costs) is reasonably possible. The range of

such disallowance is from zero to some maximum amount, and no point within the range is more likely than any other. In that situation, because a disallowance of the maximum amount in the range is reasonably possible and thus inclusion of that amount in rates is no longer probable, subsequent capitalization of AFUDC should be discontinued for an amount of costs equal to the maximum amount that is within the range.

Definition of Probable

69. The term *probable* was defined in Statement 71 differently from how it has been defined in other authoritative literature. The Board used a definition based on the definition used in FASB Concepts Statement No. 3, *Elements of Financial Statements of Business Enterprises*, because that definition was one of the criteria of an asset in Concepts Statement 3.

70. The AICPA Issues Paper questioned whether that definition was intended to be significantly different from the definition used in Statement 5 and indicated that the use of different definitions had caused some confusion in practice. The Board considered the concern expressed in the AICPA Issues Paper and decided to change the definition in Statement 71 to the definition in Statement 5.

71. Some respondents to the Exposure Draft indicated their belief that the definition included in this Statement was a more stringent one than that contained in FASB Concepts Statement No. 6, *Elements of Financial Statements*, and in Statement 71. In their view, the definition in this Statement is appropriate for loss recognition, but the definition that was originally included in Statement 71 was more appropriate for asset recognition. The Board believes that a single concept is involved, and one definition can be applied in practice more easily than two. Thus, the Board concluded that the change in definition in this Statement is appropriate.

Accounting for Phase-in Plans

72. The Exposure Draft proposed specific accounting for phase-in plans. After considering comments received, both in comment letters and during the public hearing, the Board concluded that additional consideration is necessary to resolve the accounting issues related to phase-in plans. Accordingly, the Board decided to issue this Statement on plant abandonments and disallowances of plant costs and to consider further how to address accounting for phase-in plans.

Effective Date and Transition

73. The Board considered whether this Statement should be applied only to events occurring after the effective date or to all events of the types addressed. Applying this Statement only to events occurring after the effective date would diminish both comparability of the resulting financial statements among enterprises and consistency within an enterprise that had experienced such events both before and after the effective date. The events addressed by this Statement tend to have long-lasting effects on financial statements. For example, a decision whether to recognize a disallowance of plant cost as a loss affects reported depreciation and net income for the life of the related plant. Accordingly, the Board decided that this Statement should be applied to all abandoned plants and disallowed plant costs, regardless of whether those events occurred before or will occur after the effective date.

74. The Exposure Draft was proposed to be effective for fiscal years beginning after December 15, 1986. The Board requested respondents who believed that additional delay in that proposed effective date was warranted for their specific situations to describe their existing circumstances in detail and

explain why a delay would be appropriate and what it would accomplish.

75. Most of the respondents who requested a delay in application of the proposed Statement cited phase-in plans that might be modified if this Statement were to address accounting for phase-in plans. Few respondents indicated that a regulator's disallowance might be reconsidered or that a regulator's decision about recovery on an abandoned plant might be reconsidered.

76. Many respondents to the Exposure Draft indicated that this Statement should not be applied to regulatory actions that occurred before the effective date. They indicated that covenants, entered into without knowledge of the accounting requirements of this Statement, may now result in unintended restrictions on companies' actions. The Board recognizes that creditors may be willing to modify existing covenants for some enterprises that will be affected by this Statement. Although the Board decided to make this Statement effective for fiscal years beginning after December 15, 1987, it also decided to permit enterprises to delay application of this Statement until fiscal years beginning after December 15, 1988 if (a) application of this Statement would cause a violation or probable future violation of a restrictive clause in an existing loan indenture or other agreement and (b) the enterprise is actively seeking to obtain modification of that restrictive clause.

Appendix C: BACKGROUND INFORMATION

77. Statement 71 was issued in December 1982, effective for financial statements for fiscal years beginning after December 15, 1983. In early 1984, several different circumstances caused the Board to question whether the application of Statement 71 in practice was what the Board had intended.

78. During 1984, representatives of some regulatory commissions began to question the cost of certain new plants and to discuss possible major disallowances. Also, several plants in advanced stages of construction were abandoned. In a few states, courts ruled that utilities could not recover the costs of those abandoned plants from customers.

79. As a result of Board member concerns, the Board asked the staff to investigate whether guidance on the application of Statement 71 was needed in practice. The staff met several times with committees of Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners, and the Public Utilities Subcommittee of the American Institute of Certified Public Accountants (the AICPA Subcommittee). The Board also met with representatives of those groups and staff members of the Federal Energy Regulatory Commission.

80. In November 1984, the Board received an AICPA Issues Paper on emerging issues in the public utility industry. That paper listed 17 specific issues related to current problems in the electric utility industry identified by the AICPA Subcommittee. The Board also received a comment letter from EEI on the issues raised in the AICPA Issues Paper.

81. In April 1985, the Board's Task Force on Regulated Enterprises met and discussed a staff draft of a possible Exposure Draft that encompassed most of the conclusions included in this Statement.

82. Subsequent to the April 1985 task force meeting, the Board received 51 letters from 39 affected enterprises and other interested parties commenting on the positions proposed in the staff draft discussed at the task force meeting and on the Board's tentative conclusions reached at its public meetings subsequent to that task force meeting.

83. The Board issued an Exposure Draft in December 1985. More than 1,400 organizations and individuals responded to that Exposure Draft, many with multiple letters.

84. In June 1986, the Board held a public hearing on the proposals in the Exposure Draft. Sixty-six individuals and firms presented their views at the four-day public hearing.

85. After considering comments received in comment letters and at the public hearing, the Board concluded that additional consideration is necessary to resolve the accounting issues related to phase-in plans. After consideration, the Board decided to issue this Statement to address accounting for plant abandonments and disallowances of plant costs. The Board will consider accounting for phase-in plans further at a later date.

UE-88 REMAND / PGE EXHIBIT / 6300
QUENNOZ - PETERSON - DAHLGREN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Asset Classification

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen M. Quennoz
Leonard S. Peterson
Randy Dahlgren

February 15, 2005

I. Introduction

Q. Please state your name and position with Portland General Electric.

A. My name is Stephen M. Quennoz. I am Vice President of Generation with Portland General Electric. My qualifications appear at the end of this testimony.

My name is Leonard ("Pete") S. Peterson. I am a Federal Policy Analyst with Portland General Electric. My qualifications appear at the end of this testimony.

My name is Randy Dahlgren. I am Director of Regulatory Policy and Affairs at PGE. My qualifications appear in Section III of PGE Exhibit 6100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to review the 1995 asset classifications of Trojan for cost recovery.

Q. How is your testimony organized?

A. We first provide a description of the Staff and PGE perspectives expressed in 1994 regarding Trojan asset classification. We describe the Commission's decision concerning asset classification in Order 95-322. We then discuss how the remand of UE-88 affects those decisions and the need to re-evaluate the amount of Trojan plant remaining in service following closure. Finally, we describe how PGE determined the amount of Trojan assets that should have remained as plant-in-service.

II. Trojan Asset Classification in UE-88

Q. Please describe PGE's position regarding the Trojan asset classification for cost recovery in UE-88.

A. In 1992, PGE first identified those Trojan assets that remained in service following plant closure. In 1994, PGE testified that approximately $130 million of gross Trojan assets (approximately $80 million of net Trojan assets) continued to be used and useful and should be classified as plant-in-service (i.e., FERC account 101). PGE maintained that these assets were used and useful because "the Trojan plant remaining in FERC account 101 protects public health and safety, provides security, or provides office space and facilities for the employees remaining on site" (PGE Exhibit 2000, page 69).

Q. Which assets did PGE maintain were still in service?

A. As discussed in PGE Exhibit 900, PGE operated Trojan pursuant to a license from the NRC. Even after Trojan ceased producing electricity, a number of its systems were required by the terms of the NRC license. PGE identified the major systems still in service. These included the control, reactor auxiliary, central and fuel buildings; main control and electric board; intake structure; plant wiring; service water; fire protection; cooling water; clean radwaste treatment; gaseous radwaste treatment; instrument racks and panels, tools, equipment and fixtures; and diesel engine generators. All of these systems were still required under the terms of PGE's NRC license (PGE Exhibit 900, page 43).

Q. Did PGE provide any additional support for its position?

A. Yes. PGE provided two additional pieces as support: 1) a letter from the Chief Accountant at FERC that approved PGE's proposed Trojan asset classification; and 2) a copy of the Report of Independent Public Accountants that certified the accuracy of PGE's FERC-based financial reporting, which included the Trojan assets as plant-in-service. We have included the appropriate work papers as PGE Exhibit 6301.

Q. Did Staff agree with PGE's position?

A. No. Staff argued that the referenced assets were needed primarily for decommissioning and were a result of past, not current operations of the plant. Consequently, Staff maintained that no Trojan assets were used and useful and all such assets should be classified as regulatory assets in FERC account 182.2.

Q. What did the Commission decide on this issue?

A. The Commission ultimately agreed with Staff and specified that "All Trojan plant investment...should be transferred to FERC Account 182.2, Unrecovered Plant and Regulatory and Regulatory Study Costs" (Order No. 95-322, page 54).

Q. Did any other factors influence the Commission's decision regarding Trojan asset classification?

A. Yes. At the time of its decision in UE-88, the Commission was relying on the framework of its earlier decision in DR 10. Specifically, the Commission believed that it could provide both the recovery of, and a return on, plant no longer in service, as long as these could be demonstrated to be in the public interest. Given this framework, the Commission decision on asset classification was largely an accounting issue. It had no impact on the rates that were set in UE-88.

Q. What did Staff and the Commission say?

A. Both Staff and the Commission observed that because both FERC accounts 101 and 182.2 are in rate base, "transferring investment between the accounts will not affect the rate base" (Staff Exhibit 66, page 3 and Commission Order No. 95-322, page 53).

III. Implications of UE-88 Remand

Q. Does the remand of UE-88 impact the Commission's decision regarding Trojan asset classification?

A. Yes. In light of the court's interpretation of ORS 757.355, the Commission should reconsider its analysis. Following the 1995 decision, PGE earned a return on plant assets in both accounting classifications, so the distinction between the two was not necessarily material. Now, however, the classification has a direct impact on PGE's rate base and the ratemaking treatment that follows from that decision.

Q. How does ORS 757.355 describe assets eligible to earn a return on investment?

A. The statute provides that "A public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer" (ORS 757.355(1)).

Q. How is "service" defined in this context?

A. ORS 756.010(8) defines service broadly. "'Service' is used in the *broadest and most inclusive sense* and includes equipment and facilities related to providing the service or the product served" (ORS 756.010(8) italics added for emphasis).

Q. Did the Commission rely upon ORS 756.010(8) and a broad definition of service in deciding the asset classification issue in UE-88?

A. We do not believe the Commission did. From the language in Order 95-322, it appears that the Commission defined "service" narrowly. The Commission stated, "As Staff notes, however, the original purpose of the assets in question was to be part of an operating plant that was providing service to ratepayers. This plant has now been permanently shut down, and those assets are now used only to provide the service necessary for safety and asset preservation pending decommissioning and dismantling of the plant" (OPUC Order No. 95-322, page 53).

Q. Did Staff and the Commission rely on any other authorities to determine that the Trojan was not plant-in-service?

A. Yes, Staff and the Commission cited Federal Accounting Standards Board (FASB) Statement No. 90 which states "When it becomes probable that an operating asset… will be abandoned, the cost of that asset shall be removed from…plant-in-service" (Staff Exhibit 66, page 5).

Q. Was Trojan abandoned in 1995?

A. No. The plant was far from abandoned in 1995 because it was in the early stages of a long and complicated decommissioning process. Further, neither Staff nor the Commission explicitly disagreed with PGE's method to identify Trojan plant-in service. In fact, Staff audited PGE's analysis and work papers and their testimony took no exception to our results. Ultimately, the Commission agreed that the referenced assets were providing service (OPUC Order No. 95-322, page 53).

Q. Are these assets necessary to protect the public health and safety?

A. Yes. These assets provide necessary service, required both before the Trojan plant was shut down and during decommissioning.

IV. Determining Asset Classification

Q. How did PGE determine which Trojan assets continued to provide service?

A. Beginning in 1992, PGE conducted an analysis to determine Trojan plant-in-service. PGE was required to accurately record Trojan assets on PGE's books and financial statements using FERC accounting standards. PGE requested and received approval from the FERC Chief Accountant for its treatment of Trojan plant-in-service (see PGE Exhibit 6301). This detailed analysis was reviewed and updated regularly through 1994 to reflect Trojan activities and PGE's understanding of the asset usage (see 1992-1994, PGE FERC Form 1, page 205, lines 17-23, provided as PGE Exhibit 6302).

Q. What was the value of Trojan plant-in-service?

A. In 1992, PGE identified $130 million gross Trojan plant-in-service (approximately $80 million net Trojan assets) following the plant closure. PGE's ongoing analysis through 1994 indicated that the value of gross Trojan plant-in-service was $150 million following the plant closure. We utilized the $130 million figure in the UE-88 rate case because, as Staff and the Commission noted, "transferring investment between the accounts will not affect the rate base" (Staff Exhibit 66, page 3 and Commission Order No. 95-322, page 53).

Q. Has PGE updated this work?

A. Yes. While the analysis of 1992-1994 was very rigorous, PGE believed that by using the same methodology, but with the experience of numerous years of decommissioning effort, we might identify a different level of Trojan plant-in-service. This value could be higher than the $80 million identified in 1992 or it could be lower. To this end, we have reviewed all Trojan assets as of 1995 and identified which ones were in fact used and useful during the following years. We relied on the same criteria that existed in 1995. Details of the analysis are provided as PGE Exhibit 6303. We identified $214.5 million gross plant-in-service and $113.6 million net plant-in-service.

Q. How, specifically, did you identify the $113.6 million?

A. We evaluated a detailed listing of Trojan assets that reflected plant balances on PGE's books in 1995 (see PGE Exhibit 6303). We performed an asset-by-asset review to determine what, if any, service the asset provided for safety, environmental protection, and/or decommissioning. If we concluded that some or all of an asset provided legitimate service, we then determined what percent of that asset should be counted as in service.

Q. Please explain.

A. If we determined an entire asset was in service, it was listed as 100 percent. If we concluded that only part of an asset was in service, we had to make a subsequent determination regarding the percent to apply. If an asset had distinct components that allowed its use to be clearly separated by function, then we applied a percent that reflected that partial use (*e.g.*, laboratory equipment and office furniture). If an asset was not realistically separable, such as the water system described in Staff Exhibit 66, pages 6-7, then it was counted as 100 percent. Several managers at the Trojan plant then reviewed our analysis. We, and the managers who prepared and reviewed this list, have decades of experience at the Trojan plant and are confident in our expert understanding of the plant's operations.

Q. Did PGE use the same process in 1992-1994 to determine Trojan plant-in-service?

A. Yes. We utilized the same process as described above. We reviewed system-level investment detail and established applicable percentages based on the whether an asset or portion of an asset provided service. If a portion of an asset provided service, we then established whether the asset's functionality was separable. If so, we applied a percent that reflected that partial use. If not, we listed the asset at 100 percent.

Q. Do you believe the current analysis is more accurate than the 1992-1994 evaluation?

A. Yes, but the current analysis is developed with hindsight. It demonstrates that the original $80 million net plant-in-service value developed in 1992 was quite reasonable. Our update supports the use of $80 million for net Trojan plant that was then presently used for utility service in UE-88.

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, General Manager at the Arkansas Nuclear One Station for Arkansas Power and Light, and Restart Manager at 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. I've held my current position of Vice President, Generation since December 2000. My responsibilities include overseeing the operations of PGE's thermal and hydro plants 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. Peterson, please describe your qualifications.

A. I have 29 years of experience in the nuclear industry, including 24 years in support of the operation and decommissioning of the Trojan Nuclear Plant. Among my decommissioning duties, I was the cost control engineer for the large component removal, reactor vessel and internals removal, and Independent Spent Fuel Storage Installation projects. In 1972, I received a Bachelors of Science in Engineering Physics from the University of Illinois, and in 1973, I obtained a Masters of Science in Nuclear Engineering from the same school. I am a registered Professional Engineer and am currently enrolled in the Graduate Certificate

Program in Applied Energy Economics and Policy at Portland State University. I am now a Federal Policy Analyst in PGE's Federal Regulatory Affairs Department.

Q. Does this conclude your testimony?

A. Yes.

g:\ratecase\opuc\dockets\ue-88 remand\testimony\quennoz-peterson - asset classification\admin-testimony_2-10-05\pge_exhibit 6300_witness_quennoz.peterson.doc

List of Exhibits

PGE Exhibit	Description
6301	UE-88 PGE Rebuttal Work papers - Trojan Investment Classification
6302	PGE FERC Form 1 – 1992 - 1994, Pages 204-205
6303	Current Analysis of Trojan Asset Classification

Workpapers

S-46: Trojan Investment Classification

Portland General Electric Company

March 1, 1993

Mr. Russell E. Faudree, Jr.
Chief Accountant
Federal Energy Regulatory Commission
825 N. Capitol Street, N.E.
Washington, D.C. 20426

Subject: Accounting for the Premature Retirement of the Trojan Nuclear Power Plant

Dear Mr. Faudree:

Portland General Electric Company (PGE) operates Trojan and owns 67.5% of the plant. The plant went operational in 1976 and its NRC approved license permitted operations until February 2011. A plan approved in August 1992 had Trojan being phased out of operations over a four year period ending in 1996. This decision was part of PGE's 1992 Integrated Resource Plan (also known as our Least Cost Plan or LCP) filed with the Oregon Public Utility Commission (OPUC). In November 1992, Trojan was taken off line when a leak was detected in one of its steam generators. Long term economic considerations, including a belief that the regulatory uncertainties with regard to Trojan's steam generators would likely result in longer and increasingly costly outages any time Trojan is taken off line, on January 4, 1993 PGE's Board of Directors voted to recommend to the plant's other owners that Trojan permanently cease operations.

PGE hereby requests FERC approval to use Account 182.2 (Unrecovered Plant and Regulatory Study Costs) to account for certain costs associated with the premature retirement of its Trojan Nuclear Power Plant. We are also requesting your concurrence with the continued use of Account 101 (Plant in-service) for Trojan assets that will continue to operate and provide utility benefit following the plant closure. Enclosed is an original and seven copies of our request. Please provide your response to the attached accounting treatment by March 12, 1993.

This request has been concurrently submitted to the OPUC for review. Since the closure decision, we have also worked closely with the Securities and Exchange Commission (SEC) and our Independent Accountants to clarify the appropriate accounting for these costs under SFAS No.90 (Accounting for Plant Abandonments and Disallowances of Plant Costs).

121 S.W. Salmon Street, Portland, Oregon 97204

In addition, PGE has requested that the OPUC address certain policy questions regarding ratemaking issues with respect to Trojan's closure and expects a decision by mid-1993. This includes issues associated with the timing and method for amortizing amounts recorded in Account 182.2.

If you need additional information or have any questions, please contact me at (503) 464-7132 or Kirk Stevens at (503) 464-7121.

Sincerely,

Joseph E. Feltz

Joseph E. Feltz
Assistant Controller

Attachment

copy: T. Ray Lambeth (OPUC Staff)

Proposed Accounting Treatment
Closure of the Trojan Nuclear Power Plant

1. Plant Investment and Related Depreciation:
The premature retirement of Trojan is considered an "abandonment" under SFAS No. 90. Under SFAS 90, when it becomes probable an operating asset will be abandoned, the cost of the asset is removed from plant in-service and recorded as a separate new asset. Based on analysis documented in PGE's 1992 LCP, it became probable Trojan would be abandoned. Accordingly, in December 1992 PGE will retire $450 million of Trojan assets from plant in service (A/C 101) and transfer the associated undepreciated plant investment ($270 million) to Account 182.2. This entry does not include $130 million of retirement units that will continue to operate to support the security and storage of spent nuclear fuel (eg. spent fuel pool, electrical, water and security systems, admin. facilities etc.). These assets will remain in Account 101 until they no longer provide utility benefit.

Note: For SEC reporting purposes, PGE will transfer all Trojan related assets out of plant in-service (including the $130 million above) to a separate new asset based on an interpretation of SFAS 90. However, for FERC and OPUC reporting purposes, the assets that are used and useful and continue to serve their intended use in providing utility benefit, primarily the protection of public health and safety, will continue to be recorded in plant in-service (A/C 101).

In addition, at the plant closure date about $14 million of work orders were still under construction (CWIP, A/C 107), and $35 million of unamortized nuclear fuel inventories remained in A/C 120. Since these costs are "plant related" under SFAS 90, their balances will be transferred to Account 182.2 in Dec. 1992 pending future OPUC rate treatment.

2. Decommissioning Costs:
Decommissioning costs represent cost of removal/ negative salvage and, accordingly, should be treated as "plant related costs" under SFAS 90. Based on the event of "abandonment", in December 1992 PGE will record its remaining estimated decommissioning obligation in Account 228.4 (Accum. Miscellaneous Operating Provisions). Simultaneously, a separate new asset, representing expected future revenues, will be recorded in Account 182.2.

Discussion: Under Generally Accepted Accounting Principles (GAAP), the systematic and rational allocation used to achieve "matching" of revenues and expenses for long-lived assets is usually accomplished through depreciation over the estimated life of the related asset. The amount subject to depreciation is the difference between original cost and estimated net salvage value (residual less cost of removal). Accordingly, PGE has been systematically recognizing as depreciation expense a provision for estimated decommissioning costs over Trojan's expected service life based on amounts allowed in rates. Through December 1992, PGE has recorded about $37 million of the decommissioning obligation in Account 108.

As of 12/31/92, PGE will accrue the remaining balance of its estimated decommissioning liability on a historical cost basis (ie., inflated to the applicable year in which the costs are expected to be incurred). PGE has modified its estimate of decommissioning costs to $377 million, which recognizes the premature retirement and related impact on the timing of when costs would be incurred. This estimate includes $95 million of ongoing operating costs to be incurred from 1993 through 1998. Ongoing operating costs primarily represent manpower requirements (approximately 150 employees) to support the safety and security of nuclear fuel as it remains in our spent fuel pool. Costs estimates for dismantlement of Trojan, expected to occur during the years 1996 through 2002, were based on a study of a nuclear plant similar to Trojan. A site specific study of expected decommissioning costs for Trojan is in the planning phase and will provide us enhanced cost estimates for adjusting the liability.

The following summarizes our proposed accounting treatment for decommissioning costs:

a. Amounts Previously Provided:
Decommissioning amounts previously provided for in Account 108 will be reclassified in Dec. 1992 to the decommissioning liability:
  Dr. Accum. Provision for Deprec. (A/C 108)
  Cr. Accum. Misc. Operating Provisions (A/C 228.4)

b. Record Estimated Liability:
In December 1992, PGE will accrue the remaining balance of its estimated liability for decommissioning, with an offset to Account 182.2:
  Dr. Unrecovered Plant Costs (A/C 182.2)
  Cr. Accum. Misc. Operating Provisions (A/C 228.4)

Attached is a summary comparison of PGE's balance sheet for Trojan related costs both before and after the adjustments above.

Attachment

Pro Forma Balance Sheet
Trojan Related Costs Using A/C 182.2
(PGE Share, millions of dollars)

A/C	Description	Before	Adjust.		After
	ASSETS:				
101	Plant in-service	580	(450)	(A)	130
108	Accum. Provision-Assets	(230)	180	(A)	(50)
	" "-Decomis.	(37)	37	(C)	0
107	CWIP	14	(14)	(B)	0
120's	Nuclear Fuel Inventories	35	(35)	(B)	0
182.2	Unrecovered Plant Costs:				
	Plant Costs	0	319	(A+B)	319
	Decommissioning Costs	0	340	(D)	340
	Total A/C 182.2	0	659		659
	LIABILITIES:				
228.4	Decommissioning	0	377	(C+D)	377

(A) To transfer plant not remaining in-service and associated reserve to A/C 182.2.

(B) To transfer plant related assets (CWIP & Nuclear Fuel) to A/C 182.2.

(C) To reclassify the accumulated decommissioning reserve recorded to-date from A/C 108 to A/C 228.4.

(D) To accrue PGE's remaining estimated decommissioning liability not previously recorded and the associated 182.2 asset to be recovered in future periods.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
OCA-DAS
Docket Nos. AC93-72-000
and AC93-72-001

APR 20 1993

Portland General Electric Company
Attention: Joseph E. Feltz
Assistant Controller
121 S.W. Salmon Street
Portland, OR 97204

Ladies and Gentlemen:

This is in reply to your letters dated March 1 and March 25, 1993, requesting approval for Portland General Electric Company (PGE) to use Account 182.2, Unrecovered Plant and Regulatory Study Costs, to account for certain costs associated with the premature retirement of its interest in the Trojan Nuclear Power Plant (Trojan) at December 31, 1992. Specifically, PGE requests approval to record in Account 182.2:

- its undepreciated plant investment in Trojan of about $270 million; 1/
- its investment in construction work orders and unamortized nuclear fuel inventories of about $49 million; and
- its remaining estimated liability for decommissioning Trojan of about $340 million. 2/

1/ This entry excludes the undepreciated book value of Trojan assets that will continue to operate to support the security and storage of spent nuclear fuel.

2/ Under PGE's proposal the decommissioning liability will be recorded in Account 228.4, Accumulated Miscellaneous Operating Provisions.

Also, PGE proposes to:

- reclassify to Account 228.4, the decommissioning amounts previously recorded in Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, of about $37 million; and

- continue to classify in Account 101, Electric Plant in Service, about $130 million of Trojan assets that will continue to operate and provide utility benefit following the closure of Trojan.

You state that PGE has requested that the Oregon Public Utility Commission (OPUC) address certain policy questions regarding the ratemaking issues with respect to Trojan's closure and expects a decision by mid-1993. You indicate that this proceeding includes issues associated with the timing and method for amortizing amounts recorded in Account 182.2.

Mr. Kirk Stevens of your Company informed my staff that, until the OPUC rules on the Trojan ratemaking issues, PGE will amortize from Account 182.2 to Account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs, the amount of Trojan depreciation and decommissioning costs that is currently recovered through PGE's rates.

PGE's proposed accounting for the premature retirement of Trojan is provisionally approved. On March 31, 1993, the Commission issued Order No. 552 3/ which, in part, pertains to the recognition and measurement issues in accounting for regulatory assets. In addition, the staff of the Office of Chief Accountant has underway a project on the accounting for decommissioning of nuclear plants. If PGE's accounting for the premature retirement of Trojan is subsequently found to not be in compliance with either the provisions of Order No. 552 or any rule that may ultimately result from the staff's decommissioning project, appropriate adjustments may be required in the future.

In the event any of the costs recorded in Account 182.2 are disallowed from future rates, they shall be charged to Account 426.5, Other Deductions, in the year of disallowance.

3/ Docket No. RM92-1-000, 62 FERC ¶ 61,299.

Portland General Electric
Company

Authority to act on this matter is delegated to the Chief Accountant pursuant to § 375.303 of the Commission's regulations. This letter order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this letter order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Russell E. Faudree, Jr.

Russell E. Faudree, Jr.
Chief Accountant

Check appropriate box:

☐ Original signed form

☒ Conformed copy

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	Dec. 31, 19 93

ARTHUR ANDERSEN & CO.

Report of Independent Public Accountants

To: Portland General Electric Company

We have audited the balance sheets-regulatory basis of Portland General Electric Company as of December 31, 1993 and 1992, the related statements of income-regulatory basis, the statements of retained earnings-regulatory basis and cash flows-regulatory basis for the years then ended (financial statements), included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and proprietary capital of Portland General Electric Company as of December 31, 1993 and 1992, and the results of its operations and its cash flows for the years then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

As more fully discussed in Note 3 to the financial statements, effective January 1, 1993, the Company changed its method of accounting for income taxes.

This report is intended solely for the information and use of management of Portland General Electric Company and for filing with the Federal Energy Regulatory Commission and should not be used for any other purpose.

Arthur Andersen & Co.

Portland, Oregon
January 25, 1994 (except with respect to the matter discussed in Note 14 as to which the date is February 23, 1994)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1993

NOTES TO FINANCIAL STATEMENTS (Continued)

Effective January 1, 1993, PGE adopted Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes". Prior to SFAS No. 109, PGE accounted for income taxes in accordance with Accounting Principles Board Opinion No. 11. Prior period financial statements have not been restated. As of December 31, 1993 and 1992, the significant components of PGE's deferred income tax assets and liabilities were as follows (thousands of dollars):

	1993	1992
Deferred Tax Assets		
Plant-in-service	$ 83,602	$ 18,608
Regulatory reserve	47,718	46,804
Other	24,038	20,667
	155,358	86,079
Deferred Tax Liabilities		
Plant-in-service	(497,476)	(201,596)
Replacement power costs	(29,574)	(4,838)
WNP-3 exchange contract	(70,542)	(71,099)
Other	(88,746)	(45,779)
	$ (686,338)	$ (323,312)

As a result of implementing SFAS 109, PGE has recorded deferred tax assets and liabilities for all temporary differences between the financial statement bases and tax bases of assets and liabilities.

The Omnibus Budget Reconciliation Act of 1993 resulted in a federal tax rate increase from 34% to 35% effective January 1, 1993. The tax rate increase resulted in additional income tax expense for PGE of $3.6 million.

The IRS completed its examination of Portland General's tax returns for the years 1985 to 1987 and has issued a statutory notice of tax deficiency which Portland General is contesting. As part of this audit, the IRS has proposed to disallow PGE's 1985 WNP-3 abandonment loss deduction on the premise that it is a taxable exchange. PGE disagrees with this position and will take appropriate action to defend its deduction. Management believes that it has appropriately provided for probable tax adjustments and is of the opinion that the ultimate disposition of this matter will not have a material adverse impact on the financial condition of PGE.

NOTE 4. TROJAN NUCLEAR PLANT

Shutdown - PGE is the 67.5% owner of Trojan. In early 1993, PGE ceased commercial operation of Trojan. PGE made the decision to shut down Trojan as part of its least cost planning process, a biennial process whereby PGE evaluates a mix of energy options that yield an adequate and reliable supply of electricity at the least cost to the utility and to its customers. On June 3, 1993 the PUC acknowledged PGE's Least Cost Plan (LCP).

Decommissioning Estimate - The 1993 nuclear decommissioning estimate of $409 million represents a site-specific decommissioning cost estimate performed for Trojan by an experienced decommissioning engineering firm. This cost estimate assumes that the majority of decommissioning activities will occur between 1998 and 2002, after construction of a temporary dry spent fuel storage facility. The final decommissioning activities will occur in 2018 after PGE completes shipment of spent fuel to a United States Department of Energy (USDOE) facility.

The decommissioning cost estimate includes the cost of decommissioning planning, removal and burial of irradiated equipment and facilities as required by the Nuclear Regulatory Commission (NRC); building demolition and nonradiological site remediation; and fuel management costs including licensing, surveillance and $75 million of transition costs. Transition costs are the operating costs associated with closing Trojan, operating and maintaining the spent fuel pool and securing the plant until dismantlement can begin. Except for transition costs, which will continue to be amortized as incurred, PGE will fund the decommissioning costs through contributions to the Trojan decommissioning trust.

The 1992 decommissioning cost estimate of $411 million was based upon a study performed on a nuclear plant similar to Trojan and included the cost of dismantlement activities performed during the years 1996 through 2002, monitoring of stored spent fuel through 2018 and $130 million of miscellaneous closure and transition costs ($43 million was amortized to nuclear operating expenses during 1993).

Name of Respondent	This Report Is:	Date of R (Mo, Da, \`..)	
PORTLAND GENERAL ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1993

NOTES TO FINANCIAL STATEMENTS (Continued)

The 1992 estimate and the 1993 site-specific estimate are reflected in the financial statements in nominal dollars (actual dollars expected to be spent in each year). The difference between the 1992 and the 1993 cost estimates, reflected in nominal dollars, is due to the application of a higher inflation factor, the timing of decommissioning activities and certain changes in assumptions, such as decommissioning the temporary dry spent fuel storage facility and shipping highly activated reactor components to the USDOE repository in 2018, which are included in the 1993 estimate. Both the 1992 cost estimate and the 1993 site-specific cost estimate reflected in 1993 (current) dollars are $289 million.

Assumptions used to develop the site-specific cost estimate represent the best information PGE has currently. However, the Company is continuing its analysis of various options which could change the timing and scope of dismantling activities. Presently, PGE is planning to accelerate the timing of large component removal which could reduce overall decommissioning costs. PGE plans to submit a detailed decommissioning work plan to the NRC in mid-1994. PGE expects any future changes in estimated decommissioning costs to be incorporated in future revenues to be collected from customers.

PGE is recording an annual operating provision of $11 million for decommissioning. This provision is being collected from customers and deposited in an external trust fund. Earnings on the trust fund assets reduce the amount of decommissioning costs to be collected from customers. Trojan abandonment - decommissioning of $356 million (reflected in the deferred charges section of the Company's balance sheet) represents remaining decommissioning costs expected to be collected from customers.

Trojan decommissioning trust assets are invested primarily in investment grade tax-exempt bonds. At December 31, 1993 the trust reflects the following activity (thousands of dollars):

Beginning Balance 1/01/93	$32,945
1993 Activity	
Contributions	11,220
Earnings	4,696
Ending Balance 12/31/93	$48,861

Investment Recovery - PGE filed a general rate case on November 8, 1993 which addresses recovery of Trojan plant costs, including decommissioning. In late February 1993, the PUC granted PGE accounting authorization to continue using previously approved depreciation and decommissioning rates and lives for its Trojan investment. The Trojan plant costs have been transferred to Account 182.2, Unrecovered plant and regulatory study costs, with the exception of costs related to the spent fuel pool and related safety and security facilities, which remain in Account 101, Utility plant in service.

As stated earlier, PGE made the decision to permanently cease commercial operation of Trojan as part of its least cost planning process. Management determined that continued operation of Trojan was not cost effective. Least cost analysis assumed that recovery of the Trojan plant investment, including future decommissioning costs, would be granted by the PUC. Regarding the authority of the PUC to grant recovery, the Oregon Department of Justice (Attorney General) issued an opinion that the PUC may allow rate recovery of total plant costs, including operating expenses, taxes, decommissioning costs, return of capital invested in the plant and return on the undepreciated investment. While the Attorney General's opinion does not guarantee recovery of costs associated with the shutdown, it does clarify that under current law the PUC has authority to allow recovery of such costs in rates.

PGE asked the PUC to resolve certain legal and policy questions regarding the statutory framework for future ratemaking proceedings related to the recovery of the Trojan investment and decommissioning costs. On August 9, 1993, the PUC issued a declaratory ruling agreeing with the Attorney General's opinion discussed above. The ruling also stated that the PUC will favorably consider allowing PGE to recover in rates some or all of its return on and return of its undepreciated investment in Trojan, including decommissioning costs, if PGE meets certain conditions. PGE believes that its general rate filing provides evidence that satisfies the conditions established by the PUC.

Management believes that the PUC will grant future revenues to cover all, or substantially all, of Trojan plant costs with an appropriate return. However, future recovery of the Trojan plant investment and future decommissioning costs

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1992

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,254	
3	(302) Franchises and Consents	35,285	
4	(303) Miscellaneous Intangible Plant	30,473,460	5,289,796
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	30,513,998	5,289,796
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,107,216	
9	(311) Structures and Improvements	213,346,293	822,939
10	(312) Boiler Plant Equipment	364,309,846	5,305,115
11	(313) Engines and Engine-Driven Generators	-	
12	(314) Turbogenerator Units	89,223,012	872,611
13	(315) Accessory Electric Equipment	45,431,602	3,164
14	(316) Misc. Power Plant Equipment	12,949,559	518,707
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	729,367,528	7,522,535
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	675,568	
18	(321) Structures and Improvements	137,719,457	2,480,373
19	(322) Reactor Plant Equipment	174,340,368	15,694,702
20	(323) Turbogenerator Units	111,062,690	6,438
21	(324) Accessory Electric Equipment	51,862,455	268,328
22	(325) Misc. Power Plant Equipment	62,548,311	9,971,421
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	538,208,850	28,421,262
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	4,696,689	
26	(331) Structures and Improvements	18,841,567	2,989,039
27	(332) Reservoirs, Dams, and Waterways	109,986,206	8,054,416
28	(333) Water Wheels, Turbines, and Generators	25,584,039	604,607
29	(334) Accessory Electric Equipment	4,726,568	417,453
30	(335) Misc. Power Plant Equipment	1,960,090	140,072
31	(336) Roads, Railroads, and Bridges	4,928,835	97,147
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	170,723,995	12,302,733
33	D. Other Production Plant		
34	(340) Land and Land Rights	339,710	
35	(341) Structures and Improvements	27,568,751	361,845
36	(342) Fuel Holders, Products and Accessories	58,469,882	18,161,525
37	(343) Prime Movers	-	
38	(344) Generators	23,044,101	345,623
39	(345) Accessory Electric Equipment	11,144,257	(16,572)

Name of Respondent	This Report Is:	Date of (Mo, Da	
PORTLAND GENERAL ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1992

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ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassification or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,254	(301)	2
			35,285	(302)	3
10,019,753		(9,080)	25,734,422	(303)	4
10,019,753	-	(9,080)	25,774,961		5
					6
					7
			4,107,216	(310)	8
873,099			213,296,134	(311)	9
53,706			369,561,254	(312)	10
			-	(313)	11
1,333			90,094,290	(314)	12
16,336			45,418,429	(315)	13
45,711		490	13,423,044	(316)	14
990,185	-	490	735,900,367		15
					16
675,568				(320)	17
74,646,829		(3,867,272)	61,685,728	(321)	18
159,775,446		(1,965,551)	28,294,074	(322)	19
113,381,157		4,033,002	1,720,973	(323)	20
32,009,282		(202,163)	19,919,338	(324)	21
58,647,680		1,820,019	15,692,072	(325)	22
439,135,963	-	(181,964)	127,312,186		23
					24
			4,696,689	(330)	25
14,345		(1,129)	21,815,132	(331)	26
2,784		(5,037)	118,032,802	(332)	27
32,202			26,156,444	(333)	28
16,408		(30,234)	5,097,379	(334)	29
3,337		25,487	2,122,313	(335)	30
			5,025,982	(336)	31
69,076	-	(10,912)	182,946,741		32
					33
			339,710	(340)	34
27,120		59,319	27,962,795	(341)	35
50,764		(132,014)	76,448,629	(342)	36
			-	(343)	37
96,810		(5,263)	23,287,651	(344)	38
34,585		77,958	11,171,058	(345)	39

Name of Respondent	This Report Is:	Date of Report (Mo, D	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1993

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,254	-
3	(302) Franchises and Consents	35,285	-
4	(303) Miscellaneous Intangible Plant	25,734,422	253,979
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	25,774,961	253,979
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,107,216	-
9	(311) Structures and Improvements	213,296,134	296,401
10	(312) Boiler Plant Equipment	369,561,254	1,535,468
11	(313) Engines and Engine-Driven Generators	-	-
12	(314) Turbogenerator Units	90,094,290	1,058,777
13	(315) Accessory Electric Equipment	45,418,429	155,258
14	(316) Misc. Power Plant Equipment	13,423,044	780,081
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	735,900,367	3,825,985
16	B. Nuclear Production Plant (1)		
17	(320) Land and Land Rights	-	-
18	(321) Structures and Improvements	61,685,728	1,716,572
19	(322) Reactor Plant Equipment	28,294,074	3,283
20	(323) Turbogenerator Units	1,720,973	-
21	(324) Accessory Electric Equipment	19,919,338	39,661
22	(325) Misc. Power Plant Equipment	15,692,072	100,790
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	127,312,186	1,860,306
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	4,696,689	861,087
26	(331) Structures and Improvements	21,815,132	671,767
27	(332) Reservoirs, Dams, and Waterways	118,032,802	829,845
28	(333) Water Wheels, Turbines, and Generators	26,156,444	778,480
29	(334) Accessory Electric Equipment	5,097,379	700,291
30	(335) Misc. Power Plant Equipment	2,122,313	75,443
31	(336) Roads, Railroads, and Bridges	5,025,982	492,892
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	182,946,741	4,409,804
33	D. Other Production Plant		
34	(340) Land and Land Rights	339,710	-
35	(341) Structures and Improvements	27,962,795	311,908
36	(342) Fuel Holders, Products and Accessories	76,448,629	1,610,840
37	(343) Prime Movers	-	-
38	(344) Generators	23,287,651	6,767
39	(345) Accessory Electric Equipment	11,171,058	6

 (1) See Note 4, Trojan Nuclear Plant on Page 123.

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Name of Respondent	This Report Is:	Date (Mo,	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1993

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassification or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
-			5,254	(301)	2
-			35,285	(302)	3
315,592			25,672,810	(303)	4
315,592	-	-	25,713,348		5
					6
					7
-		-	4,107,216	(310)	8
468		-	213,592,066	(311)	9
165,031		-	370,931,692	(312)	10
-		-	-	(313)	11
-		-	91,153,066	(314)	12
-		70	45,573,757	(315)	13
7,532		-	14,195,593	(316)	14
173,031	-	70	739,553,390		15
					16
-		-	-	(320)	17
(11,775,000)		(459,007)	74,718,293	(321)	18
(2,153,848)		(137,365)	30,313,839	(322)	19
(1,187,397)		-	2,908,370	(323)	20
(1,784,002)		(5,475)	21,737,527	(324)	21
(3,982,839)		867,252	20,642,953	(325)	22
(20,883,087)	-	265,405	150,320,983		23
					24
-		-	5,557,776	(330)	25
30,552		(6,387)	22,449,960	(331)	26
107,786		(389,104)	118,365,757	(332)	27
7,562		-	26,927,361	(333)	28
6,983		3,432	5,794,120	(334)	29
15,848		39,630	2,221,539	(335)	30
783		8,699	5,526,790	(336)	31
169,514	-	(343,729)	186,843,302		32
					33
-		27,287	366,997	(340)	34
359,301		(5,139)	27,910,263	(341)	35
370,484		(102,757)	77,586,228	(342)	36
-		-	-	(343)	37
471		(1,951)	23,291,996	(344)	38
-		47	11,171,111	(345)	39

Name of Respondent	This Report Is:	Date of Report	Year of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/28/95	Dec. 31, 1994

ELECTRIC PLANT IN SERVICE (Accounts 101,102,103,and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.

2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column(d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$5,254	
3	(302) Franchises and Consents	35,285	
4	(303) Miscellaneous Intangible Plant	25,672,810	3,090,956
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$25,713,348	$3,090,956
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,107,216	
9	(311) Structures and Improvements	213,592,066	789,048
10	(312) Boiler Plant Equipment	370,931,692	4,815,439
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	91,153,066	1,841,837
13	(315) Accessory Electric Equipment	45,573,757	185,365
14	(316) Misc. Power Plant Equipment	14,195,593	571,373
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	$739,553,390	$8,203,062
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights		
18	(321) Structures and Improvements	74,718,293	171,748
19	(322) Reactor Plant Equipment	30,313,839	
20	(323) Turbo generator Units	2,908,370	
21	(324) Accessory Electric Equipment	21,737,527	2,856
22	(325) Misc. Power Plant Equipment	20,642,953	3,566
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	$150,320,983	$178,170
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	5,557,776	896
26	(331) Structures and Improvements	22,449,960	756,065
27	(332) Reservoirs, Dams, and Waterways	118,365,757	2,530,291
28	(333) Water Wheels, Turbines, and Generators	26,927,361	221,344
29	(334) Accessory Electric Equipment	5,794,120	25,880
30	(335) Misc. Power Plant Equipment	2,221,539	16,113
31	(336) Roads, Railroads, and Bridges	5,526,790	(1,031)
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	$186,843,302	$3,549,558
33	D. Other Production Plant		
34	(340) Land and Land Rights	366,997	140,519
35	(341) Structures and Improvements	27,910,263	41,367
36	(342) Fuel Holders, Products, and Accessories	77,586,228	195,143
37	(343) Prime Movers		
38	(344) Generators	23,291,996	971,002
39	(345) Accessory Electric Equipment	11,171,111	171,249

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/28/95	Dec. 31, 1994

ELECTRIC PLANT IN SERVICE (Accounts 101,102,103,and 106)(Continued)

reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column(f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399,state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]					1
			$5,254	(301)	2
			35,285	(302)	3
			28,763,766	(303)	4
			$28,804,304		5
[redacted]					6
					7
			4,107,216	(310)	8
			214,381,114	(311)	9
36,618			375,710,513	(312)	10
				(313)	11
			92,994,903	(314)	12
40,260		34,218	45,753,080	(315)	13
360,794		(0)	14,406,172	(316)	14
$437,671		$34,218	$747,352,999		15
[redacted]					16
				(320)	17
4,862,435		5,566,976	75,594,583	(321)	18
3,606,317		(33,391)	26,674,132	(322)	19
226,565		33,391	2,715,195	(323)	20
4,751,520		461	16,989,325	(324)	21
431,975		(5,744,371)	14,470,173	(325)	22
* $13,878,811		($176,934)	$136,443,407		23
[redacted]					24
			5,558,672	(330)	25
47,838		69,519	23,227,705	(331)	26
20,474		16,445	120,892,020	(332)	27
19,580		(2,022)	27,127,103	(333)	28
45,825			5,774,174	(334)	29
13,006		(3,551)	2,221,095	(335)	30
92,678		(88,681)	5,344,400	(336)	31
$239,401		($8,290)	$190,145,169		32
[redacted]					33
			507,516	(340)	34
1,062		(228)	27,950,340	(341)	35
33,581		(19)	77,747,771	(342)	36
				(343)	37
346,303		116	23,916,811	(344)	38
6,569			11,335,791	(345)	39

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
ADMIN BLDG,BLDG FRAME 8150-140-020	152,594.13 $	103,001.04	100% $	103,001.04	The Admin Bldg was used for records storage and housed communications equipment. The structure also contained a small amount of asbestos-containing material.
ADMIN BLDG,COMMUNICATIONS EQUIP 8150-140-010	553,309.10 $	373,483.64	100% $	373,483.64	Communication System used to support plant
ADMIN BLDG,EXCAVATION 8150-140-006	4,549.01 $	3,070.58	100% $	3,070.58	
ADMIN BLDG,EXTERIOR WALLS 8150-140-040	178,916.96 $	120,768.95	100% $	120,768.95	
ADMIN BLDG,FENCING 8150-140-175	46,540.65 $	31,414.94	0% $	-	Fencing was not used.
ADMIN BLDG,FIRE PROTECTION SYSTEM 8150-140-130	18,987.53 $	12,816.58	100% $	12,816.58	
ADMIN BLDG,FLOORS AND FLOOR COVERINGS 8150-140-030	26,090.20 $	17,610.89	100% $	17,610.89	
ADMIN BLDG,HVAC 8150-140-120	301,908.58 $	203,788.29	100% $	203,788.29	
ADMIN BLDG,IN-PLANT COMMUNICATION EQUIP 8150-140-125	15,222.40 $	10,275.12	100% $	10,275.12	Communications system was used.
ADMIN BLDG,INTERIOR WALLS AND CEILINGS 8150-140-050	45,321.60 $	30,592.08	100% $	30,592.08	
ADMIN BLDG,LIGHTING 8150-140-110	106,942.94 $	72,186.48	100% $	72,186.48	
ADMIN BLDG,PLUMBING 8150-140-090	54,350.04 $	36,686.28	100% $	36,686.28	
ADMIN BLDG,ROOFING GUTTERS DOWNSPOUTS 8150-140-060	26,154.39 $	17,654.21	100% $	17,654.21	
ADMIN BLDG,STRUCTURAL MATERIAL 8150-140-008	651,339.92 $	439,654.45	100% $	439,654.45	
CENTRAL BLDG,BLDG ELECTRICAL 8150-135-100	995,797.82 $	672,163.53	100% $	672,163.53	
CENTRAL BLDG,BLDG FRAME 8150-135-020	2,126,960.02 $	1,435,698.01	100% $	1,435,698.01	The Central Bldg was the main office building on-site and housed required radiation protection, decommissioning, operations, quality assurance, licensing and security personnel. As such, the structure and supporting systems and components were required.
CENTRAL BLDG,BLDG LIGHTING 8150-135-110	426.90 $	288.16	100% $	288.16	
CENTRAL BLDG,BLDG PLUMBING 8150-135-090	254,495.32 $	171,784.34	100% $	171,784.34	
CENTRAL BLDG,CABINETS, SHELVES & COUNTERS 8150-135-140	116,405.00 $	78,573.38	100% $	78,573.38	
CENTRAL BLDG,COMMUNICATION EQUIP 8150-135-010	1,129,849.52 $	762,648.43	100% $	762,648.43	
CENTRAL BLDG,COMPUTER EQUIP 8150-135-645	183,370.28 $	123,774.94	66% $	81,691.46	Staffing reduction
CENTRAL BLDG,ELEVATOR 8150-135-144	98,475.10 $	66,470.69	100% $	66,470.69	
CENTRAL BLDG,EXTERIOR WALLS 8150-135-040	65,988.93 $	44,542.53	100% $	44,542.53	
CENTRAL BLDG,FIRE PROTECTION SYSTEM 8150-135-130	141,964.05 $	95,825.73	100% $	95,825.73	
CENTRAL BLDG,FLOOR & FLOOR COVERINGS 8150-135-030	722,360.29 $	487,593.20	100% $	487,593.20	
CENTRAL BLDG,FURNITURE & OFC EQUIP 8150-135-120	2,429,148.21 $	1,639,675.04	66% $	1,082,185.53	Staffing reduction
CENTRAL BLDG,IN-PLANT COMMUNICATIONS EQUIP 8150-135-125	47,560.35 $	32,103.24	100% $	32,103.24	
CENTRAL BLDG,INSTRUMENTS RACKS AND PANELS 8150-135-256	2,310.59 $	1,559.65	100% $	1,559.65	
CENTRAL BLDG,INTERIOR WALLS & CEILINGS 8150-135-050	1,025,369.44 $	692,124.37	100% $	692,124.37	
CENTRAL BLDG,LANDSCAPING 8150-135-011	48,226.75 $	32,553.06	0% $	-	No longer necessary
CENTRAL BLDG,ROADS, ROADWAYS, AND PARKING LOTS 8150-135-035	105,498.00 $	71,211.15	100% $	71,211.15	
CENTRAL BLDG,ROOFING, GUTTERS & DOWNSPOUTS 8150-135-060	262,650.27 $	177,288.93	100% $	177,288.93	
CENTRAL BLDG,SECURITY SYSTEM 8150-135-123	57,917.05 $	39,094.01	100% $	39,094.01	
CENTRAL BLDG,SEWAGE DISPOSAL SYSTEM 8150-135-080	94,454.79 $	63,756.98	100% $	63,756.98	
CONDENSATE DEMINERALIZER BLDG,480-V AUXILIARY SYSTEM 8150-260-618	18,272.68 $	12,334.06	100% $	12,334.06	The Condensate Demineralizer Bldg contained a small amount of radioactive material, and was extensively used in subsequent years as a radioactive waste processing facility. The structure itself and support systems were necessary radiological barriers.
CONDENSATE DEMINERALIZER BLDG,BLDG FRAME 8150-260-020	399,420.97 $	269,609.15	100% $	269,609.15	
CONDENSATE DEMINERALIZER BLDG,CARD KEY ACCESS SYSTEM 8150-260-911	16,178.31 $	10,920.36	100% $	10,920.36	
CONDENSATE DEMINERALIZER BLDG,CONDENSATE DEMINERALIZER SYSTEM 8150-260-434	3,612,622.51 $	2,438,520.19	0% $	-	No longer used
CONDENSATE DEMINERALIZER BLDG,CRANES & HOISTS 8150-260-805	51,702.06 $	34,898.89	100% $	34,898.89	
CONDENSATE DEMINERALIZER BLDG,ELECTRICAL SYSTEM 8150-260-001	836,312.45 $	564,510.90	100% $	564,510.90	
CONDENSATE DEMINERALIZER BLDG,EXCAVATION 8150-260-006	5,775.38 $	3,898.38	100% $	3,898.38	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
CONDENSATE DEMINERALIZER BLDG,EXTERIOR WALLS 8150-260-040	1,534,027.39	$ 1,035,468.49	100%	$ 1,035,468.49	
CONDENSATE DEMINERALIZER BLDG,FIRE PROTECTION SYSTEM 8150-260-130	40,534.53	$ 27,360.81	100%	$ 27,360.81	
CONDENSATE DEMINERALIZER BLDG,FLOORS AND FLOOR COVERINGS 8150-260-030	20,565.80	$ 13,881.92	100%	$ 13,881.92	
CONDENSATE DEMINERALIZER BLDG,FOUNDATION AND BASE SLAB 8150-260-010	311,640.78	$ 210,357.53	100%	$ 210,357.53	
CONDENSATE DEMINERALIZER BLDG,HVAC 8150-260-120	173,318.31	$ 116,989.86	100%	$ 116,989.86	
CONDENSATE DEMINERALIZER BLDG,INTERIOR WALLS 8150-260-050	17,113.51	$ 11,551.62	100%	$ 11,551.62	
CONDENSATE DEMINERALIZER BLDG,LIGHTING AND CONTROLS 8150-260-110	36,795.20	$ 24,836.76	100%	$ 24,836.76	
CONDENSATE DEMINERALIZER BLDG,PAINTING 8150-260-070	1,171.03	$ 790.45	100%	$ 790.45	
CONDENSATE DEMINERALIZER BLDG,PLUMBING 8150-260-090	112,985.84	$ 76,265.44	100%	$ 76,265.44	
CONDENSATE DEMINERALIZER BLDG,ROOFS GUTTERS DOWNSPOUTS 8150-260-060	24,201.15	$ 16,335.78	100%	$ 16,335.78	
CONDENSATE DEMINERALIZER BLDG,STRUCTURAL MATERIAL 8150-260-008	68,148.27	$ 46,000.08	100%	$ 46,000.08	
CONTROL BLDG,12.5KV AUXILIARY SYSTEM 8150-300-616	51,829.47	$ 34,984.89	100%	$ 34,984.89	The Control Building housed the main control room, electrical switchgear & distribution rooms, controlled access points for security and radiation protection purposes, mechanical and computer rooms, and the control and instrumentation shop.
CONTROL BLDG,120-V AC INSTRUMENT SYSTEM 8150-300-630	457,026.34	$ 308,492.78	100%	$ 308,492.78	Included were electrical power, instrumentation and control systems necessary for Spent Fuel Pool cooling and radiation monitoring.
CONTROL BLDG,4160-V AUXILIARY SYSTEM 8150-300-617	28,544.32	$ 19,267.42	100%	$ 19,267.42	
CONTROL BLDG,480-V AUXILIARY SYSTEM 8150-300-618	197,668.03	$ 133,425.92	100%	$ 133,425.92	
CONTROL BLDG,ACCOUSTIC LEAK MONITOR SYSTEM 8150-300-445	264,890.89	$ 178,801.35	0%	$ -	No longer used
CONTROL BLDG,AUXILIARY FEEDWATER SYSTEM 8150-300-432	348,600.45	$ 235,305.30	0%	$ -	No longer used
CONTROL BLDG,CABINETS SHELVES AND COUNTERS 8150-300-140	928,971.42	$ 627,055.71	100%	$ 627,055.71	
CONTROL BLDG,CARD KEY ACCESS SYSTEM 8150-300-911	190,317.92	$ 128,464.60	100%	$ 128,464.60	
CONTROL BLDG,CIRCULATING WATER SYSTEM 8150-300-435	41,916.25	$ 28,293.47	0%	$ -	No longer used
CONTROL BLDG,COMMUNICATIONS EQUP 8150-300-010	457,951.19	$ 309,117.05	100%	$ 309,117.05	The main control room was required to be manned 24 hours a day by the Nuclear Regulatory Commission in order to monitor the spent fuel pool and take action if necessary.
CONTROL BLDG,COMPONENT COOLING WATER SYSTEM 8150-300-216	497,954.09	$ 336,119.01	0%	$ -	No longer used
CONTROL BLDG,COMPUTER EQUIP (TOC ANALYZER) 8150-300-645	5,454,469.80	$ 3,681,767.12	100%	$ 3,681,767.12	
CONTROL BLDG,CONTROL ROD DRIVE POWER 8150-300-635	5,564.61	$ 3,756.11	0%	$ -	No longer used
CONTROL BLDG,DC ELECTRICAL SYSTEM 8150-300-620	1,271,111.90	$ 858,000.53	100%	$ 858,000.53	DC system necessary for elect. Control pwr
CONTROL BLDG,DEMINERALIZER SYSTEM 8150-300-243	35,911.18	$ 24,240.05	0%	$ -	No longer used
CONTROL BLDG,DIESEL FUEL OIL SYSTEM 8150-300-626	78,272.67	$ 52,834.05	0%	$ -	No longer used
CONTROL BLDG,ELEVATORS 8150-300-144	118,264.03	$ 79,828.22	100%	$ 79,828.22	
CONTROL BLDG,EXCAVATION 8150-300-006	20,688.11	$ 13,964.47	100%	$ 13,964.47	
CONTROL BLDG,EXTERIOR WALLS 8150-300-040	2,448,694.73	$ 1,652,868.94	100%	$ 1,652,868.94	
CONTROL BLDG,FIRE PROTECTION EQUIP 8150-300-130	5,755,942.58	$ 3,885,261.24	100%	$ 3,885,261.24	
CONTROL BLDG,FIXED AREA RADIATION MONITOR 8150-300-260	12,482.83	$ 8,425.91	100%	$ 8,425.91	
CONTROL BLDG,FLOORS AND FLOOR COVERINGS 8150-300-030	199,126.42	$ 134,410.33	100%	$ 134,410.33	
CONTROL BLDG,FURNITURE & OFC EQUIP 8150-300-100	167,122.37	$ 112,807.60	100%	$ 112,807.60	
CONTROL BUILDING,BLDG FRAME 8150-300-020	2,208,672.14	$ 1,490,853.69	100%	$ 1,490,853.69	
CONTROL BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-300-425	205,802.65	$ 138,916.79	100%	$ 138,916.79	
CONTROL BUILDING,IN-PLANT COMMUNICATIONS EQUIP 8150-300-125	136,980.77	$ 92,462.02	100%	$ 92,462.02	
CONTROL BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-300-810	80,142.60	$ 54,096.26	100%	$ 54,096.26	
CONTROL BUILDING,INSTRUMENTATION AND CONTROL 8150-300-261	1,572,621.26	$ 1,061,519.35	40%	$ 424,607.74	
CONTROL BUILDING,INSTRUMENTS RACKS & PANELS 8150-300-460	1,265,374.17	$ 854,127.56	40%	$ 341,651.03	
CONTROL BUILDING,INTEGRATED LEAK RATE TESTING SYSTEM 8150-300-257	80,863.23	$ 54,582.68	0%	$ -	No longer used
CONTROL BUILDING,INTERIOR WALLS AND CEILINGS 8150-300-050	757,841.86	$ 511,543.26	100%	$ 511,543.26	
CONTROL BUILDING,LAB EQUIPMENT 8150-300-134	322,896.37	$ 217,955.05	40%	$ 87,182.02	
CONTROL BUILDING,LADDERS AND STAIRWAYS 8150-300-013	81,613.35	$ 55,089.01	100%	$ 55,089.01	
CONTROL BUILDING,LIGHTING AND CONTROLS 8150-300-110	1,123,399.31	$ 758,294.53	100%	$ 758,294.53	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
CONTROL BUILDING,MAIN CONTROL & ELECTRIC BOARD 8150-300-640	12,144,189.24	$ 8,197,327.74	40%	$ 3,278,931.09	
CONTROL BUILDING,METEOROLOGY INSTRUMENTS 8150-300-220	52,799.43	$ 35,639.62	100%	$ 35,639.62	
CONTROL BUILDING,MISC GAS SUPPLY SYSTEM 8150-300-815	387,069.75	$ 261,272.08	50%	$ 130,636.04	Used Nitrogen and sample gasses
CONTROL BUILDING,NSSS COMPUTER 8150-300-269	1,016,406.04	$ 686,074.08	0%	$ -	
CONTROL BUILDING,PLUMBING 8150-300-090	874,215.47	$ 590,095.44	100%	$ 590,095.44	
CONTROL BUILDING,POWER SYSTEMS 8150-300-265	400,493.57	$ 270,333.16	100%	$ 270,333.16	
CONTROL BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-300-262	646,876.16	$ 436,641.41	100%	$ 436,641.41	All radiation monitors still in service
CONTROL BUILDING,PROCESS SAMPLING SYSTEM 8150-300-267	154,846.48	$ 104,521.37	10%	$ 10,452.14	
CONTROL BUILDING,PROCESS STEAM SYSTEM 8150-300-422	8,444.45	$ 5,700.00	0%	$ -	No longer used
CONTROL BUILDING,REACTOR CONTROL AND PROTECTION SYSTEM 8150-300-264	1,116,727.04	$ 753,790.75	0%	$ -	No longer used
CONTROL BUILDING,REACTOR CONTROLS 8150-300-212	9,934.35	$ 6,705.69	0%	$ -	No longer used
CONTROL BUILDING,REMOTE SHUTDOWN STATION 8150-300-680	10,204,594.97	$ 6,888,101.60	0%	$ -	No longer used
CONTROL BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-300-060	81,275.14	$ 54,860.72	100%	$ 54,860.72	
CONTROL BUILDING,SECURITY EQUIPMENT 8150-300-120	11,569,440.96	$ 7,809,372.65	100%	$ 7,809,372.65	
CONTROL BUILDING,SECURITY EQUIPMENT 8150-300-123	2,712,061.80	$ 1,830,641.72	100%	$ 1,830,641.72	
CONTROL BUILDING,SERVICE WATER SYSTEM 8150-300-440	1,359,272.76	$ 917,509.11	100%	$ 917,509.11	
CONTROL BUILDING,STATION AND AREA RADIATION MONITORING EQUIP 8150-300-135	1,140,805.93	$ 770,044.00	100%	$ 770,044.00	
CONTROL BUILDING,STORES EQUIPMENT 8150-300-138	1,850.00	$ 1,248.75	40%	$ 499.50	
CONTROL BUILDING,STRUCTURAL MATERIAL 8150-300-008	241,624.11	$ 163,096.27	100%	$ 163,096.27	
CONTROL BUILDING,TOOLS & EQUIPMENT 8150-300-136	310,223.53	$ 209,400.88	40%	$ 83,760.35	
CONTROL BUILDING,TURBINE-GENERATOR CONTROL PANEL 8150-300-407	12,894.76	$ 8,703.96	0%	$ -	No longer used
CONTROL BUILDING,UNDISTRIBUTED PROPERTY 8150-300-001	370,488.24	$ 250,079.56	0%	$ -	
COOLING TOWER,AVIATION WARNING LIGHTS 8150-340-060	174,908.44	$ 118,063.20	100%	$ 118,063.20	Tower height made it an aviation hazard
COOLING TOWER,BASIN AND OUTLET STRUCTURE 8150-340-020	926,216.14	$ 625,195.89	100%	$ 625,195.89	The cooling lower structure contained asbestos-containing fill material that required cleanup to protect the safety of the public.
COOLING TOWER,CIRCULATING WATER SYSTEM 8150-340-435	62,396.10	$ 42,117.37	0%	$ -	
COOLING TOWER,COMMUNICATIONS EQUIPMENT 8150-340-010	855,151.89	$ 577,227.53	100%	$ 577,227.53	
COOLING TOWER,CONDENSATE SYSTEM 8150-340-430	22,144.94	$ 14,947.83	0%	$ -	
COOLING TOWER,FILL AND FILL SUPPORTS 8150-340-093	3,641,798.67	$ 2,458,214.10	100%	$ 2,458,214.10	Asbestos-containing material (the cooling tower fill material) remained in 1995 and had to be removed and disposed of safely.
COOLING TOWER,INSTRUMENTS RACKS AND PANELS 8150-340-460	16,978.69	$ 11,460.62	0%	$ -	
COOLING TOWER,MECHANICAL FACILITIES 8150-340-419	499,877.83	$ 337,417.54	0%	$ -	
COOLING TOWER,TOWER SUPPORTS AND VEIL 8150-340-030	3,740,477.23	$ 2,524,822.13	100%	$ 2,524,822.13	The cooling lower structure contained asbestos-containing fill material that required cleanup to prote the safety of the public.
COOLING TOWER,WATER PIPING SYSTEM 8150-340-090	240,390.78	$ 162,263.78	0%	$ -	
DECHLORINATION BUILDING,BUILDING FRAME 8150-280-020	4,572.15	$ 3,086.20	100%	$ 3,086.20	Dechlorination required by NPDES permit before discharge into the Columbia River.
DECHLORINATION BUILDING,DOMESTIC WATER SYSTEM 8150-280-451	6,429.42	$ 4,339.86	100%	$ 4,339.86	
DECHLORINATION BUILDING,EXCAVATION 8150-400-006	2,150.82	$ 1,451.80	100%	$ 1,451.80	
DECHLORINATION BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-400-120	10,167.93	$ 6,863.35	100%	$ 6,863.35	
DECHLORINATION BUILDING,LADDERS AND STAIRWAYS 8150-400-013	7,380.65	$ 4,981.94	100%	$ 4,981.94	
DECHLORINATION BUILDING,LIGHTING AND CONTROLS 8150-280-110	21,092.68	$ 14,237.56	100%	$ 14,237.56	
DECHLORINATION BUILDING,MISC GAS SUPPLY SYSTEM 8150-280-815	1,178.14	$ 795.24	100%	$ 795.24	
DECHLORINATION BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-400-060	484.40	$ 326.97	100%	$ 326.97	
DECHLORINATION BUILDING,STRUCTURAL MATERIAL 8150-400-008	25,379.28	$ 17,131.01	100%	$ 17,131.01	
FIRE EXTINGUISHERS,COMPANY NUMBER 6000 - 6999 8150-050-006	2,182.84	$ 1,473.42	100%	$ 1,473.42	Fire protection required for personnel safety and to prevent spread of radioactive material.
FIRE EXTINGUISHERS,COMPANY NUMBERS 0000-0999 8150-050-980	6,344.51	$ 4,282.54	100%	$ 4,282.54	
FIRE EXTINGUISHERS,COMPANY NUMBERS 03000-03999 8150-050-003	46,136.52	$ 31,142.15	100%	$ 31,142.15	
FIRE EXTINGUISHERS,COMPANY NUMBERS 04000-04999 8150-050-004	8,891.40	$ 6,001.70	100%	$ 6,001.70	
FIRE EXTINGUISHERS,COMPANY NUMBERS 05000-05999 8150-050-005	13,511.72	$ 9,120.41	100%	$ 9,120.41	
FIRE EXTINGUISHERS,COMPANY NUMBERS 1000-1999 8150-050-001	2,022.56	$ 1,365.23	100%	$ 1,365.23	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
FIRE EXTINGUISHERS,COMPANY NUMBERS 7000 - 7999 8150-050-007	1,912.41	$ 1,290.88	100%	$ 1,290.88	
FIRE EXTINGUISHERS,FIRE EXTINGUISHER, NO COMPANY NUMBER 8150-050-999	1,335.77	$ 901.64	100%	$ 901.64	
FISH REARING FACILITIES,CONTROL WIRING 8150-040-490	9,927.12	$ 6,700.81	0%	$ -	No longer used.
FISH REARING FACILITIES,HEAT TRACING SYSTEM 8150-040-648	59,956.66	$ 40,470.75	0%	$ -	
FISH REARING FACILITIES,INSTRUMENTS RACKS AND PANELS 8150-040-256	64,726.07	$ 43,690.10	0%	$ -	
FISH REARING FACILITIES,SITE AND YARD DEVELOPMENT 8150-040-412	115,688.04	$ 78,089.43	0%	$ -	
FISH REARING FACILITIES,WARM WATER SUPPLY 8150-040-444	1,077,688.05	$ 727,439.43	0%	$ -	
FUEL BUILDING,480-V AUXILIARY SYSTEM 8150-220-618	6,130.41	$ 4,138.03	100%	$ 4,138.03	The Fuel Bldg contained the Spent Fuel Pool (which contained spent nuclear fuel), radiation and pool leakage monitoring equipment, and other support systems for the spent fuel pool.
FUEL BUILDING,AUXILIARY STEAM SYSTEM 8150-220-421	2,513.06	$ 1,696.32	0%	$ -	Not used.
FUEL BUILDING,BUILDING FRAME 8150-220-020	1,484,790.61	$ 1,002,233.66	100%	$ 1,002,233.66	The Fuel Bldg also contained radioactively contaminated rooms and equipment, radioactive waste storage and treatment equipment, and asbestos-containing material, all of which had to be contained.
FUEL BUILDING,CABINETS SHELVES AND COUNTERS 8150-220-140	97,934.84	$ 66,106.02	100%	$ 66,106.02	
FUEL BUILDING,CARD KEY ACCESS SYSTEM 8150-220-911	32,960.40	$ 22,248.27	100%	$ 22,248.27	
FUEL BUILDING,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-220-224	2,711,354.10	$ 1,830,164.02	0%	$ -	Not used.
FUEL BUILDING,CIRCULATING WATER SYSTEM 8150-220-435	95,509.65	$ 64,469.01	0%	$ -	Not used.
FUEL BUILDING,CLEAN RADWASTE TREATMENT SYSTEM 8150-220-250	1,337,112.45	$ 902,550.90	100%	$ 902,550.90	
FUEL BUILDING,COMPONENT COOLING WATER SYSTEM 8150-220-216	2,661,538.30	$ 1,796,538.35	100%	$ 1,796,538.35	Used for the SFP Cooling
FUEL BUILDING,CONTAINMENT SPRAY SYSTEM 8150-220-227	519,069.35	$ 350,371.81	0%	$ -	Not used.
FUEL BUILDING,CRANES & HOISTS 8150-220-805	465,262.13	$ 314,051.94	100%	$ 314,051.94	The Fuel Bldg also contained equipment, tools and spare parts necessary for removing the spent fuel from the pool and into radiation shielding casks.
FUEL BUILDING,DECONTAMINATION SYSTEM 8150-220-255	541,120.39	$ 365,256.26	100%	$ 365,256.26	
FUEL BUILDING,DEMINERALIZER SYSTEM 8150-220-243	141,643.63	$ 95,609.45	20%	$ 19,121.89	Rad. Waste and SFP cooling demins.
FUEL BUILDING,DIESEL FUEL OIL SYSTEM 8150-220-626	60,752.10	$ 41,007.67	0%	$ -	Not used.
FUEL BUILDING,DOMESTIC WATER SYSTEM 8150-220-451	40,512.39	$ 27,345.86	100%	$ 27,345.86	
FUEL BUILDING,EXCAVATION 8150-220-008	10,969.80	$ 7,404.62	100%	$ 7,404.62	
FUEL BUILDING,EXTERIOR WALLS 8150-220-040	789,462.01	$ 532,886.86	100%	$ 532,886.86	
FUEL BUILDING,FENCING 8150-220-175	404,477.74	$ 273,022.47	100%	$ 273,022.47	
FUEL BUILDING,FIRE PROTECTION EQUIPMENT 8150-220-130	1,048,024.70	$ 707,416.67	100%	$ 707,416.67	
FUEL BUILDING,FIXED AREA RADIATION MONITOR SYSTEM 8150-220-260	13,149.21	$ 8,875.72	100%	$ 8,875.72	
FUEL BUILDING,FLOORS AND FLOOR COVERINGS 8150-220-030	703,047.01	$ 474,556.73	100%	$ 474,556.73	
FUEL BUILDING,FOUNDATIONS 8150-220-010	22,682.82	$ 15,310.90	100%	$ 15,310.90	
FUEL BUILDING,FUEL BUILDING HEAT AND VENT SYSTEM 8150-220-229	123,843.94	$ 83,594.66	100%	$ 83,594.66	
FUEL BUILDING,FUEL HANDLING AND STORAGE EQUIPMENT 8150-220-231	112,424.77	$ 75,886.72	100%	$ 75,886.72	
FUEL BUILDING,GASEOUS RADWASTE TREATMENT SYSTEM 8150-220-252	268,173.79	$ 181,017.31	0%	$ -	Not used.
FUEL BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-220-120	1,855,889.15	$ 1,252,725.18	100%	$ 1,252,725.18	
FUEL BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-220-425	91,021.48	$ 61,439.50	100%	$ 61,439.50	
FUEL BUILDING,IN-PLANT COMMUNICATION EQUIP. 8150-220-125	1,925.17	$ 1,299.49	100%	$ 1,299.49	
FUEL BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-220-810	1,681,755.58	$ 1,135,185.02	50%	$ 567,592.51	
FUEL BUILDING,INSTRUMENTS RACKS & PANELS 8150-220-460	82,356.88	$ 55,590.89	50%	$ 27,795.45	
FUEL BUILDING,INSTRUMENTS RACKS AND PANELS 8150-220-256	1,027,735.57	$ 693,721.51	50%	$ 346,860.75	
FUEL BUILDING,INTERIOR WALLS AND CEILING 8150-220-050	1,610,483.03	$ 1,087,076.05	100%	$ 1,087,076.05	
FUEL BUILDING,LADDERS AND STAIRWAYS 8150-220-013	7,484.20	$ 5,051.84	100%	$ 5,051.84	
FUEL BUILDING,LIGHTING AND CONTROLS 8150-220-110	280,252.68	$ 189,170.56	100%	$ 189,170.56	
FUEL BUILDING,MAKE-UP WATER TREATMENT SYSTEM 8150-220-446	24,694.20	$ 16,668.59	50%	$ 8,334.29	Used for CCW and SFP makeup
FUEL BUILDING,MISC GAS SUPPLY SYSTEM 8150-220-815	147,636.16	$ 99,654.41	30%	$ 29,896.32	Used for CCW Nitrogen
FUEL BUILDING,PLUMBING 8150-220-090	97,946.04	$ 66,113.58	100%	$ 66,113.58	
FUEL BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-220-225	59,084.40	$ 39,881.97	0%	$ -	Not used.

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
FUEL BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-220-245	106,663.02	$ 71,997.54	0%	$ -	Not used.
FUEL BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-220-262	5,057.99	$ 3,414.14	100%	$ 3,414.14	
FUEL BUILDING,PROCESS SAMPLING SYSTEM 8150-220-267	100,794.45	$ 68,036.25	20%	$ 13,607.25	
FUEL BUILDING,PROCESS STEAM SYSTEM 8150-220-422	652,375.15	$ 440,353.23	0%	$ -	Not used.
FUEL BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-220-060	36,477.49	$ 24,622.31	100%	$ 24,622.31	
FUEL BUILDING,SAFETY INJECTION SYSTEM 8150-220-214	27,434.17	$ 18,518.06	0%	$ -	Not used.
FUEL BUILDING,SERVICE WATER SYSTEM 8150-220-440	1,681,374.68	$ 1,134,927.91	50%	$ 567,463.95	
FUEL BUILDING,SOLID RADWASTE TREATMENT SYSTEM 8150-220-253	429,572.68	$ 289,961.56	0%	$ -	Not used.
FUEL BUILDING,SPENT FUEL POOL COOLING SYSTEM 8150-220-233	1,645,599.82	$ 1,110,779.88	100%	$ 1,110,779.88	
FUEL BUILDING,STORES EQUIPMENT 8150-220-138	6,345.99	$ 4,283.54	100%	$ 4,283.54	
FUEL BUILDING,STRUCTURAL MATERIAL 8150-220-008	130,816.51	$ 88,301.14	100%	$ 88,301.14	
FUEL BUILDING,TOOLS & EQUIPMENT 8150-220-136	122,594.77	$ 82,751.47	100%	$ 82,751.47	
FUEL BUILDING,TOOLS EQUIPMENT AND FIXTURES 8150-220-232	4,639,984.70	$ 3,131,989.67	100%	$ 3,131,989.67	
GUARDHOUSE,120 8150-070-120	353,896.24	$ 238,879.96	100%	$ 238,879.96	Security-related. Security protect the public from the theft of radioactive material and terrorist activities.
GUARDHOUSE,BUILDING FRAME 8150-070-020	39,232.11	$ 26,481.67	100%	$ 26,481.67	
GUARDHOUSE,CABINETS SHELVES & COUNTERS 8150-070-140	33,820.75	$ 22,829.01	100%	$ 22,829.01	
GUARDHOUSE,CARD KEY ACCESS SYSTEM 8150-070-911	1,299,672.57	$ 877,278.98	100%	$ 877,278.98	
GUARDHOUSE,COMMUNICATIONS EQUIPMENT 8150-070-010	124,714.54	$ 84,182.31	100%	$ 84,182.31	
GUARDHOUSE,EXTERIOR WALLS 8150-070-040	202,780.05	$ 136,876.53	100%	$ 136,876.53	
GUARDHOUSE,FLOOR & FLOOR COVERINGS 8150-070-030	19,515.79	$ 13,173.16	100%	$ 13,173.16	
GUARDHOUSE,FURNITURE & OFFICE EQUIPMENT 8150-070-100	29,230.99	$ 19,730.92	100%	$ 19,730.92	
GUARDHOUSE,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-070-125	18,310.07	$ 12,359.30	100%	$ 12,359.30	
GUARDHOUSE,INTERIOR WALLS & CEILINGS 8150-070-050	1,720,305.72	$ 1,161,206.36	100%	$ 1,161,206.36	
GUARDHOUSE,LIGHTING 8150-070-110	86,007.45	$ 58,055.03	100%	$ 58,055.03	
GUARDHOUSE,PLUMBING 8150-070-090	16,853.12	$ 11,375.86	100%	$ 11,375.86	
GUARDHOUSE,ROOFING GUTTERS DOWNSPOUTS 8150-070-060	11,781.49	$ 7,952.51	100%	$ 7,952.51	
GUARDHOUSE,SECURITY EQUIPMENT 8150-070-123	2,006,017.41	$ 1,354,061.75	100%	$ 1,354,061.75	
IN PLANT COMMUNICATION SYSTEM,IN PLANT COMMUNICATION EQUIPMENT 8150-333-125	1,822,545.06	$ 1,230,217.92	100%	$ 1,230,217.92	Necessary for required plant operations.
INTAKE STRUCTURE,480-V AUXILIARY SYSTEM 8150-360-618	161,209.77	$ 108,816.59	100%	$ 108,816.59	The Intake Structure included structures, equipment and components for taking water from the Columbia River and pumping it into the plant for cooling purposes (including the spent fuel) and for fire protection.
INTAKE STRUCTURE,BUILDING FRAME 8150-360-020	26,152.59	$ 17,653.00	100%	$ 17,653.00	
INTAKE STRUCTURE,CARD KEY ACCESS SYSTEM 8150-360-911	16,480.20	$ 11,124.14	100%	$ 11,124.14	
INTAKE STRUCTURE,CHLORINATION SYSTEM 8150-360-447	188,922.14	$ 127,522.44	50%	$ 63,761.22	Using the Sodium Hypochlorinate for Serv. Water
INTAKE STRUCTURE,CIRCULATING WATER SYSTEM 8150-360-435	241,070.63	$ 162,722.68	0%	$ -	
INTAKE STRUCTURE,CRANES & HOISTS 8150-360-805	19,047.32	$ 12,856.94	100%	$ 12,856.94	
INTAKE STRUCTURE,DIESEL FUEL OIL SYSTEM 8150-360-626	60,977.43	$ 41,159.77	100%	$ 41,159.77	
INTAKE STRUCTURE,EXCAVATION 8150-360-006	8,605.46	$ 5,808.69	100%	$ 5,808.69	
INTAKE STRUCTURE,EXTERIOR WALLS 8150-360-040	44,593.26	$ 30,100.45	100%	$ 30,100.45	
INTAKE STRUCTURE,FIRE PROTECTION EQUIPMENT 8150-360-130	642,981.31	$ 434,012.38	100%	$ 434,012.38	
INTAKE STRUCTURE,FOUNDATION AND BASE SLAB 8150-360-010	767,172.88	$ 517,841.69	100%	$ 517,841.69	
INTAKE STRUCTURE,FURNITURE & OFFICE EQUIPMENT 8150-360-100	508.03	$ 342.92	100%	$ 342.92	
INTAKE STRUCTURE,HEAT VENTILATING AND AIR CONDITIONING 8150-360-120	73,279.94	$ 49,463.96	100%	$ 49,463.96	
INTAKE STRUCTURE,INSTRUMENT & SERVICE AIR SYSTEM 8150-360-810	180,591.74	$ 121,899.42	100%	$ 121,899.42	
INTAKE STRUCTURE,INSTRUMENTS RACKS AND PANELS 8150-360-256	110,430.21	$ 74,540.39	100%	$ 74,540.39	
INTAKE STRUCTURE,INSTRUMENTS RACKS AND PANELS 8150-360-460	76,986.18	$ 51,965.67	100%	$ 51,965.67	
INTAKE STRUCTURE,INTAKE SCREEN WASH SYSTEM 8150-360-450	414,095.07	$ 279,514.17	100%	$ 279,514.17	
INTAKE STRUCTURE,LIGHTING AND CONTROLS 8150-360-110	201,921.22	$ 136,296.82	100%	$ 136,296.82	
INTAKE STRUCTURE,MAKE-UP WATER TREATMENT SYSTEM 8150-360-446	119,427.43	$ 80,613.52	100%	$ 80,613.52	Makup to SFP and CCW
INTAKE STRUCTURE,MECHANICAL FACILITIES 8150-360-419	451,786.95	$ 304,956.19	100%	$ 304,956.19	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
INTAKE STRUCTURE,PLUMBING 8150-360-090	7,961.90	$ 5,374.28	100%	$ 5,374.28	
INTAKE STRUCTURE,ROOFS GUTTERS DOWNSPOUTS 8150-360-060	6,564.80	$ 4,431.24	100%	$ 4,431.24	
INTAKE STRUCTURE,SECURITY EQUIPMENT 8150-360-123	14.40	$ 9.72	100%	$ 9.72	
INTAKE STRUCTURE,SERVICE WATER SYSTEM 8150-360-440	884,692.30	$ 597,167.30	100%	$ 597,167.30	
INTAKE STRUCTURE,STRUCTURAL MATERIAL 8150-360-008	101,542.79	$ 68,541.38	100%	$ 68,541.38	
INTANGIBLE PLANT,COMPUTER SOFTWARE 8150-005-003	13,604,788.91	$ 9,183,232.51	10%	$ 918,323.25	Some of the intangibles (e.g., computer software) were used for radiation protection and security purposes.
LABORATORY EQUIPMENT,COMPANY NUMBERS 10000-10999 8150-500-010	146,918.80	$ 99,170.19	75%	$ 74,377.64	Used for analyzing required radioactive and non-radioactive (e.g., residual chlorine in discharge) samples
LABORATORY EQUIPMENT,COMPANY NUMBERS 1000-1999 8150-500-001	193,143.29	$ 130,371.72	75%	$ 97,778.79	
LABORATORY EQUIPMENT,COMPANY NUMBERS 11000-11999 8150-500-011	161,940.39	$ 109,309.76	75%	$ 81,982.32	
LABORATORY EQUIPMENT,COMPANY NUMBERS 16000-16999 8150-500-016	384.90	$ 259.81	75%	$ 194.86	
LABORATORY EQUIPMENT,COMPANY NUMBERS 2000-2999 8150-500-002	3,174.49	$ 2,142.78	75%	$ 1,607.09	
LABORATORY EQUIPMENT,COMPANY NUMBERS 3000-3999 8150-500-003	632.71	$ 427.08	75%	$ 320.31	
LABORATORY EQUIPMENT,COMPANY NUMBERS 4000-4999 8150-500-004	26,127.24	$ 17,635.89	75%	$ 13,226.92	
LABORATORY EQUIPMENT,COMPANY NUMBERS 5000-5999 8150-500-005	50,803.17	$ 34,292.14	75%	$ 25,719.10	
LABORATORY EQUIPMENT,COMPANY NUMBERS 6000-6999 8150-500-006	105,899.19	$ 71,481.95	75%	$ 53,611.46	
LABORATORY EQUIPMENT,COMPANY NUMBERS 7000-7999 8150-500-007	429,526.32	$ 289,930.27	75%	$ 217,447.70	
LABORATORY EQUIPMENT,COMPANY NUMBERS 8000-8999 8150-500-008	356,463.36	$ 240,612.77	75%	$ 180,459.58	
LABORATORY EQUIPMENT,COMPANY NUMBERS 9000-9999 8150-500-009	261,847.41	$ 176,747.00	75%	$ 132,560.25	
LABORATORY EQUIPMENT,COMPANY NUMBERS EQUAL TO ZERO 8150-500-020	1,319,450.94	$ 890,629.38	75%	$ 667,972.04	
LABORATORY EQUIPMENT,COMPANY NUMBERS LESS THAN 1000 8150-500-100	149,520.23	$ 100,926.16	75%	$ 75,694.62	
LABORATORY EQUIPMENT,STORE ISSUE TICKET ITEMS NOT NUMBERED 8150-500-101	104,822.75	$ 70,755.36	75%	$ 53,066.52	
LIQUID/STEEL STORAGE WAREHOUSE,OUTSIDE FACILITIES 8150-255-020	143,763.29	$ 97,040.22	100%	$ 97,040.22	Hazardous materials and metals that would be used later on in decommissioning activities were stored here.
LOWER COLUMBIA RIVER LABORATORY,240-V AUXILIARY SYSTEM 8150-090-510	5,842.03	$ 3,943.37	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,COMMUNICATIONS EQUIPMENT 8150-090-010	1,016.88	$ 686.39	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,EXTERIOR WALLS 8150-090-040	20,387.63	$ 13,761.65	100%	$ 13,761.65	Structure needed because building contained asbestos-containing material.
LOWER COLUMBIA RIVER LABORATORY,FLOORS AND FLOOR COVERINGS 8150-090-030	4,272.05	$ 2,883.63	100%	$ 2,883.63	
LOWER COLUMBIA RIVER LABORATORY,FOUNDATION AND BASE SLAB 8150-090-012	6,555.76	$ 4,425.14	100%	$ 4,425.14	
LOWER COLUMBIA RIVER LABORATORY,FURNITURE & OFFICE EQUIPMENT 8150-090-100	34,915.16	$ 23,567.73	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-090-125	2,396.56	$ 1,617.68	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,LAB EQUIPMENT 8150-090-134	31,749.26	$ 21,430.75	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,MISCELLANEOUS BUILDING EQUIPMENT 8150-090-199	38,485.50	$ 25,977.71	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,OUTSIDE FACILITIES 8150-090-006	45,012.53	$ 30,383.46	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,PARTITIONS AND CEILINGS 8150-090-050	44,614.71	$ 30,114.93	0%	$ -	Not used.
LOWER COLUMBIA RIVER LABORATORY,PLUMBING 8150-090-090	65,561.04	$ 44,253.70	0%	$ -	
LOWER COLUMBIA RIVER LABORATORY,ROOFS GUTTERS AND DOWNSPOUTS 8150-090-060	15,787.22	$ 10,656.37	100%	$ 10,656.37	
LOWER COLUMBIA RIVER LABORATORY,STORES EQUIPMENT 8150-090-138	477.17	$ 322.09	0%	$ -	
MAIN STEAM SUPPORT STRUCTURE (MSSS),AUXILIARY FEEDWATER SYSTEM 8150-245-432	105,239.73	$ 71,036.82	0%	$ -	
MAIN STEAM SUPPORT STRUCTURE (MSSS),EXTERIOR WALLS 8150-245-040	104,165.15	$ 70,311.48	100%	$ 70,311.48	Structure needed; small area contaminated.
MAIN STEAM SUPPORT STRUCTURE (MSSS),LADDERS AND STAIRWAYS 8150-245-013	279,825.86	$ 188,882.46	100%	$ 188,882.46	Structure needed; small area contaminated.
MAIN STEAM SUPPORT STRUCTURE (MSSS),MAIN CONTROL AND ELECTRIC BOARD 8150-245-640	424,253.44	$ 286,371.07	100%	$ 286,371.07	Essent. All electrically sys. Still in service
MAIN STEAM SUPPORT STRUCTURE (MSSS),PLUMBING 8150-245-090	6,358.13	$ 4,291.74	100%	$ 4,291.74	All drains still in service
MAINTENANCE CONTRACTORS SHOP,BUILDING FRAME 8150-155-020	469,830.68	$ 317,135.71	100%	$ 317,135.71	Maintenance shops were needed for decommissioning activities.
MAINTENANCE CONTRACTORS SHOP,ELECTRICAL SYSTEM 8150-155-100	9,454.78	$ 6,381.98	100%	$ 6,381.98	
MAINTENANCE CONTRACTORS SHOP,HEAT VENTILATING & AIR CONDITIONING 8150-155-120	9,259.89	$ 6,250.43	100%	$ 6,250.43	
MAINTENANCE SHOP,COMPUTER EQUIPMENT 8150-150-645	47,799.95	$ 32,264.97	100%	$ 32,264.97	Maintenance shops were needed for decommissioning activities.
MAINTENANCE SHOP,CRANES & HOISTS 8150-150-805	9,120.13	$ 6,156.09	100%	$ 6,156.09	
MAINTENANCE SHOP,FURNITURE AND OFFICE EQUIPMENT 8150-150-100	10,765.95	$ 7,267.02	100%	$ 7,267.02	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
MAINTENANCE SHOP,IN-PLANT COMMUNICATION EQUIP. 8150-150-125	853.38	$ 576.03	100%	$ 576.03	
MAINTENANCE SHOP,LAB EQUIPMENT 8150-150-134	11,915.62	$ 8,043.04	100%	$ 8,043.04	
MAINTENANCE SHOP,MORE TOOLS & EQUIPMENT 8150-150-137	460,809.11	$ 311,046.15	100%	$ 311,046.15	
MAINTENANCE SHOP,STORES EQUIPMENT 8150-150-138	10,132.70	$ 6,839.57	100%	$ 6,839.57	
MAINTENANCE SHOP,TOOLS & EQUIPMENT 8150-150-136	1,150,606.64	$ 776,659.48	100%	$ 776,659.48	
METEOROLOGY YARD,ACCESS ROAD-METEOROLOGY TOWER 8150-080-300	4,551.76	$ 3,072.44	100%	$ 3,072.44	The met. Tower still in service with reduced function.
METEOROLOGY YARD,FENCING 8150-080-175	604.89	$ 408.30	100%	$ 408.30	
METEOROLOGY YARD,INSTRUMENT BUILDING 8150-080-060	3,134.81	$ 2,116.00	100%	$ 2,116.00	
METEOROLOGY YARD,METEOROLOGY INSTRUMENTS 8150-080-220	243,907.44	$ 164,637.52	25%	$ 41,159.38	
METEOROLOGY YARD,METEOROLOGY TOWER & EQUIPMENT 8150-080-250	2,497.88	$ 1,686.07	100%	$ 1,686.07	
METEOROLOGY YARD,METEOROLOGY TOWER 8150-080-200	32,595.49	$ 22,001.96	100%	$ 22,001.96	
METEOROLOGY YARD,METEOROLOGY TOWER LIGHTING 8150-080-230	42,782.52	$ 28,878.20	100%	$ 28,878.20	
METEOROLOGY YARD,METEOROLOGY YARD 8150-080-010	519.07	$ 350.37	100%	$ 350.37	
MOBILE AREA,CELLULAR TELEPHONES 8150-330-020	13,238.93	$ 8,936.28	0%	$ -	
MOBILE AREA,COMMUNICATIONS EQUIPMENT 8150-330-010	21,799.82	$ 14,714.88	0%	$ -	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),BUILDING FRAME 8150-425-020	105,563.80	$ 71,255.57	100%	$ 71,255.57	Facility used for asset recovery and document storage. Comm. System still in service
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),CABINETS SHELVES AND COUNTERS 8150-425-140	72,013.81	$ 48,609.32	0%	$ -	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),COMMUNICATIONS SYSTEM 8150-425-010	1,098,269.97	$ 741,332.23	100%	$ 741,332.23	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),COMPUTER EQUIPMENT 8150-425-645	64,192.55	$ 43,329.97	100%	$ 43,329.97	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),ELEVATORS 8150-425-144	46,947.05	$ 31,689.26	100%	$ 31,689.26	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),EXTERIOR WALLS 8150-425-040	74,651.22	$ 50,389.57	100%	$ 50,389.57	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),FIRE PROTECTION EQUIPMENT 8150-425-130	231,282.57	$ 156,115.73	100%	$ 156,115.73	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),FLOORS AND FLOOR COVERINGS 8150-425-030	738,530.34	$ 498,507.98	100%	$ 498,507.98	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),FURNITURE AND OFFICE EQUIPMENT 8150-425-100	1,002,085.73	$ 676,407.87	0%	$ -	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),HEAT VENTILATING AND AIR CONDITIONING 8150-425-120	1,164,393.73	$ 785,965.77	100%	$ 785,965.77	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),IN-PLANT COMMUNICATIONS EQUIPMENT 8150-425-125	65,682.56	$ 44,335.73	100%	$ 44,335.73	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),INTERIOR WALLS AND CEILINGS 8150-425-050	758,766.53	$ 512,167.41	100%	$ 512,167.41	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),LADDERS AND STAIRWAYS 8150-425-013	104,942.39	$ 70,836.11	100%	$ 70,836.11	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),ROOFS GUTTERS DOWNSPOUTS 8150-425-060	148,025.04	$ 99,916.90	100%	$ 99,916.90	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),SEWAGE DISPOSAL SYSTEM 8150-425-080	8,781.96	$ 5,927.82	100%	$ 5,927.82	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),STRUCTURAL MATERIAL 8150-425-008	696,786.33	$ 470,330.77	100%	$ 470,330.77	
NUCLEAR ENGINEERING OFFICE BLDG (NORTH BLDG),TELEPHONE COMMUNICATION 8150-425-019	425,043.59	$ 286,904.42	100%	$ 286,904.42	
OFFICE EQUIPMENT,1992/1993 MASS PROPERTY PER PRESTON 8150-520-092	2,525,782.68	$ 1,704,903.31	20%	$ 340,980.66	Portion used for security, radiation protection, operations, quality assurance , Independent Fuel Storage Installation (ISFSI) project and decommissioning personnel.
OFFICE EQUIPMENT,COMPANY NUMBERS 1000 - 1999 8150-520-010	786.64	$ 530.98	20%	$ 106.20	(Reduced as a percentage of personnel on-site. Roughly 200 out of 1000 or more.)
OFFICE EQUIPMENT,COMPANY NUMBERS 11000-11999 8150-520-111	9,514.30	$ 6,422.15	20%	$ 1,284.43	
OFFICE EQUIPMENT,COMPANY NUMBERS 12000-12999 8150-520-112	756.00	$ 510.30	20%	$ 102.06	
OFFICE EQUIPMENT,COMPANY NUMBERS 14000-14999 8150-520-400	698.00	$ 471.15	20%	$ 94.23	
OFFICE EQUIPMENT,COMPANY NUMBERS 15000-15999 8150-520-150	1,119.00	$ 755.33	20%	$ 151.07	
OFFICE EQUIPMENT,COMPANY NUMBERS 5000-5999 8150-520-050	752,786.44	$ 508,130.85	20%	$ 101,626.17	
OFFICE EQUIPMENT,COMPANY NUMBERS 6000 - 6999 8150-520-060	169,830.23	$ 114,635.41	20%	$ 22,927.08	
OFFICE EQUIPMENT,COMPANY NUMBERS 8000-8999 8150-520-080	4,208.79	$ 2,840.93	20%	$ 568.19	
OFFICE EQUIPMENT,COMPANY NUMBERS 9000-9999 8150-520-090	14,746.47	$ 9,953.87	20%	$ 1,990.77	
OFFICE EQUIPMENT,OFFICE EQUIPMENT, NO COMPANY NUMBER 8150-520-999	1,972,366.76	$ 1,331,347.56	20%	$ 266,269.51	
OFFICE FURNITURE,COMPANY NUMBERS 0001-0999 8150-510-005	44,141.59	$ 29,795.57	20%	$ 5,959.11	
OFFICE FURNITURE,COMPANY NUMBERS 1000-1999 8150-510-010	134,242.40	$ 90,613.62	20%	$ 18,122.72	
OFFICE FURNITURE,COMPANY NUMBERS 2000-2999 8150-510-020	16,766.92	$ 11,317.67	20%	$ 2,263.53	
OFFICE FURNITURE,COMPANY NUMBERS 3000-3999 8150-510-030	117,756.71	$ 79,485.78	20%	$ 15,897.16	
OFFICE FURNITURE,COMPANY NUMBERS 4000-4999 8150-510-040	17,618.65	$ 11,892.59	20%	$ 2,378.52	
OFFICE FURNITURE,COMPANY NUMBERS 5000-5999 8150-510-050	46,798.69	$ 31,589.12	20%	$ 6,317.82	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
OFFICE FURNITURE,FURNITURE, NO COMPANY NUMBER 8150-510-999	424,841.41	$ 286,767.95	20%	$ 57,353.59	
OFFICE FURNITURE,MASS PROPERTY ITEMS 8150-510-998	1,195,596.50	$ 807,027.64	20%	$ 161,405.53	
OLD WAREHOUSE,TOOLS AND EQUIPMENT 8150-250-136	249,728.68	$ 168,566.86	50%	$ 84,283.43	Portion of old WSH Warehouse used for ISFSI project and packaging area for LCR project.
ON-SITE WAREHOUSE (NEW),BUILDING FRAME 8150-445-020	832,948.25	$ 562,240.07	100%	$ 562,240.07	Warehouse used for parts and material shipment receipt for decommissioning activities.
ON-SITE WAREHOUSE (NEW),COMPUTER EQUIPMENT 8150-445-645	41,783.30	$ 28,203.73	100%	$ 28,203.73	
ON-SITE WAREHOUSE (NEW),EXCAVATION 8150-445-006	69,418.42	$ 46,857.43	100%	$ 46,857.43	
ON-SITE WAREHOUSE (NEW),FOUNDATION AND BASE SLAB 8150-445-010	1,145,792.24	$ 773,409.76	100%	$ 773,409.76	
ON-SITE WAREHOUSE (NEW),FURNITURE & OFFICE EQUIPMENT 8150-445-100	2,106.74	$ 1,422.05	100%	$ 1,422.05	
ON-SITE WAREHOUSE (NEW),STOREROOM EQUIPMENT 8150-445-138	649,684.17	$ 438,536.81	100%	$ 438,536.81	Warehouse used for parts and material shipment receipt for decommissioning activities.
OUTSIDE FACILITIES,12.5-KV AUXILIARY SYSTEM 8150-020-617	182,299.18	$ 123,051.95	100%	$ 123,051.95	Switchyard was necessary for electrical power, barge facilities were needed for barge shipments of radioactive components, fire protection equipment was necessary, domestic water was needed for plant personnel.
OUTSIDE FACILITIES,4160-V AUXILIARY SYSTEM 8150-020-616	133,985.79	$ 90,440.41	100%	$ 90,440.41	
OUTSIDE FACILITIES,480-V AUXILIARY SYSTEM 8150-020-618	12,460.06	$ 8,410.54	100%	$ 8,410.54	
OUTSIDE FACILITIES,AUXILIARY FEEDWATER SYSTEM 8150-020-432	233,167.51	$ 157,388.07	0%	$ -	
OUTSIDE FACILITIES,BARGE UNLOADING BASIN 8150-020-034	272,584.43	$ 183,994.49	100%	$ 183,994.49	
OUTSIDE FACILITIES,CATHODIC PROTECTION SYSTEM 8150-020-650	677,399.25	$ 457,244.49	100%	$ 457,244.49	
OUTSIDE FACILITIES,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-020-224	265,388.52	$ 179,137.25	0%	$ -	
OUTSIDE FACILITIES,CHLORINATION SYSTEM 8150-020-447	257,584.03	$ 173,869.22	0%	$ -	
OUTSIDE FACILITIES,CIRCULATING WATER SYSTEM 8150-020-435	5,550,061.87	$ 3,746,291.76	0%	$ -	
OUTSIDE FACILITIES,CLEAN RADWASTE TREATMENT SYSTEM 8150-020-250	208,660.75	$ 140,846.01	100%	$ 140,846.01	
OUTSIDE FACILITIES,COMMUNICATIONS EQUIPMENT 8150-020-010	2,263,746.28	$ 1,528,028.74	100%	$ 1,528,028.74	
OUTSIDE FACILITIES,CONDENSATE SYSTEM 8150-020-430	360,323.68	$ 243,218.48	0%	$ -	
OUTSIDE FACILITIES,DECHLORINATION SYSTEM 8150-020-448	379,888.41	$ 256,424.68	100%	$ 256,424.68	
OUTSIDE FACILITIES,DIESEL FUEL OIL SYSTEM 8150-020-626	671,685.75	$ 453,387.88	0%	$ -	
OUTSIDE FACILITIES,DOMESTIC WATER SYSTEM 8150-020-451	1,791,948.00	$ 1,209,564.90	100%	$ 1,209,564.90	System used to support decom. Act., CCW, SFP, all site facilities, etc. .
OUTSIDE FACILITIES,FENCING 8150-020-175	801,125.53	$ 540,759.73	100%	$ 540,759.73	
OUTSIDE FACILITIES,FIRE PROTECTION EQUIPMENT 8150-020-130	751,530.76	$ 507,283.26	100%	$ 507,283.26	
OUTSIDE FACILITIES,GENERATOR COOLING AND VENT SYSTEM 8150-020-570	30,000.03	$ 20,250.02	0%	$ -	
OUTSIDE FACILITIES,GROUNDING SYSTEM 8150-020-655	263,136.88	$ 177,617.39	100%	$ 177,617.39	
OUTSIDE FACILITIES,GROUNDS EQUIPMENT 8150-020-610	3,928.76	$ 2,651.91	100%	$ 2,651.91	
OUTSIDE FACILITIES,GUARD TOWERS 8150-020-037	1,432,705.81	$ 967,076.42	0%	$ -	Not used.
OUTSIDE FACILITIES,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-020-425	245,067.40	$ 165,420.50	100%	$ 165,420.50	
OUTSIDE FACILITIES,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-020-125	134,913.88	$ 91,066.87	100%	$ 91,066.87	
OUTSIDE FACILITIES,INSTRUMENT & SERVICE AIR SYSTEM 8150-020-810	666,046.18	$ 449,581.17	100%	$ 449,581.17	
OUTSIDE FACILITIES,INSTRUMENTS RACKS AND PANELS 8150-020-460	255,889.41	$ 172,725.35	30%	$ 51,817.61	
OUTSIDE FACILITIES,ISOLATED PHASE BUS 8150-020-200	331,634.55	$ 223,853.32	0%	$ -	
OUTSIDE FACILITIES,LADDERS AND STAIRWAYS 8150-020-013	194,351.75	$ 131,187.43	100%	$ 131,187.43	
OUTSIDE FACILITIES,LAND & LAND RIGHTS 8150-020-005	840,663.36	$ 567,447.77	100%	$ 567,447.77	
OUTSIDE FACILITIES,LANDSCAPING 8150-020-011	1,002.16	$ 676.46	0%	$ -	
OUTSIDE FACILITIES,LIGHTING AND CONTROLS 8150-020-110	202,708.51	$ 136,828.24	100%	$ 136,828.24	
OUTSIDE FACILITIES,MAIN STEAM SYSTEM 8150-020-420	5,556,423.29	$ 3,750,585.72	0%	$ -	
OUTSIDE FACILITIES,MAKE-UP WATER TREATMENT SYSTEM 8150-020-446	1,346,671.36	$ 909,003.17	100%	$ 909,003.17	System used to support decom. Act., CCW, SFP, site facilities, etc.
OUTSIDE FACILITIES,METEOROLOGICAL MONITORING-KALAMA WASH 8150-020-139	6,061.30	$ 4,091.38	0%	$ -	
OUTSIDE FACILITIES,METEOROLOGICAL MONITORING-KELSO WASH 8150-020-135	2,948.30	$ 1,990.10	0%	$ -	
OUTSIDE FACILITIES,MISCELLANEOUS 8150-020-900	256,964.68	$ 173,451.16	30%	$ 52,035.35	
OUTSIDE FACILITIES,OREGON STATE HIGHWAY 8150-020-029	63,183.57	$ 42,648.91	100%	$ 42,648.91	
OUTSIDE FACILITIES,PRIMARY MAKE-UP WATER SYSTEM 8150-020-225	335,534.07	$ 226,465.50	0%	$ -	
OUTSIDE FACILITIES,PROCESS STEAM SYSTEM 8150-020-422	26,496.47	$ 17,885.12	0%	$ -	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
OUTSIDE FACILITIES,RAILROAD SPURS 8150-020-032	239.27	$ 161.51	0%	$ -	
OUTSIDE FACILITIES,ROADWAYS AND PARKING 8150-020-030	2,036,638.88	$ 1,374,731.24	100%	$ 1,374,731.24	
OUTSIDE FACILITIES,SAFETY INJECTION SYSTEM 8150-020-214	533,079.40	$ 359,828.60	0%	$ -	
OUTSIDE FACILITIES,SECURITY EQUIPMENT 8150-020-120	3,090,156.22	$ 2,085,855.45	100%	$ 2,085,855.45	Security required for protection against security threats.
OUTSIDE FACILITIES,SERVICE WATER SYSTEM 8150-020-440	3,778,166.83	$ 2,550,262.61	100%	$ 2,550,262.61	
OUTSIDE FACILITIES,SEWAGE DISPOSAL SYSTEM 8150-020-080	1,992,403.90	$ 1,344,872.63	100%	$ 1,344,872.63	The sewage treatment system protected the environment.
OUTSIDE FACILITIES,SIGNS 8150-020-520	110,873.98	$ 74,839.94	100%	$ 74,839.94	
OUTSIDE FACILITIES,SIRENS AND RERP RELATED EQUIP. TAX CD 218 8150-020-905	926,003.07	$ 625,052.07	0%	$ -	
OUTSIDE FACILITIES,START-UP BOILER BLDG 8150-020-040	51,916.88	$ 35,043.89	0%	$ -	
OUTSIDE FACILITIES,TELEPHONE COMMUNICATIONS 8150-020-019	475,149.75	$ 320,726.08	100%	$ 320,726.08	
OUTSIDE FACILITIES,TRAILER FACILITIES INSIDE PROTECTED AREA 8150-020-015	282,144.54	$ 190,447.56	0%	$ -	Not used.
OUTSIDE FACILITIES,UNDERGROUND DUCTWAYS 8150-020-670	635,977.01	$ 429,284.48	100%	$ 429,284.48	
OUTSIDE FACILITIES,UNDISTRIBUTED PROPERTY CHARGE 8150-020-001	395,203.50	$ 266,762.36	0%	$ -	
OUTSIDE FACILITIES,UNDISTRIBUTED PROPERTY CHARGE 8150-020-002	0.61	$ 0.41	0%	$ -	
OUTSIDE FACILITIES,VEHICLE GATE GUARDHOUSE 8150-020-036	6,152.91	$ 4,153.21	100%	$ 4,153.21	
OUTSIDE FACILITIES,WIRE LINE TERMINAL EQUIPMENT 8150-020-020	367,697.31	$ 248,195.68	100%	$ 248,195.68	
OUTSIDE FACILITIES,YARD AND MISC STRUCTURE MATERIAL 8150-020-007	1,095,334.05	$ 739,350.48	100%	$ 739,350.48	
OUTSIDE FACILITIES,YARD AREA LIGHTING 8150-020-510	523,100.10	$ 353,092.57	100%	$ 353,092.57	
OUTSIDE FACILITIES,YARD LOOP DISTRIBUTION SYSTEM 8150-020-490	531,276.16	$ *358,611.41	100%	$ 358,611.41	
PLANT COMPUTER EQUIPMENT,COMPUTER EQUIPMENT 8150-390-645	740,055.75	$ 499,537.63	10%	$ 49,953.76	A portion was used for monitoring the spent fuel pool and radioactive waste treatment systems.
PLANT COMPUTER EQUIPMENT,COMPUTER FURNITURE 8150-390-644	902.00	$ 608.85	10%	$ 60.89	
PLANT WIRING & ACCESSORIES,4160-V AUXILIARY SYSTEM 8150-380-617	3,270.86	$ 2,207.83	100%	$ 2,207.83	Essent. All electrically sys. Still in service to support functional plant systems, support decom., lighting, etc.
PLANT WIRING & ACCESSORIES,480-V AUXILIARY SYSTEM 8150-380-618	3,331.26	$ 2,248.60	100%	$ 2,248.60	
PLANT WIRING & ACCESSORIES,CABLE CONNECTIONS 8150-380-015	427,261.15	$ 288,401.28	100%	$ 288,401.28	
PLANT WIRING & ACCESSORIES,CABLE FIREPROOFING & BARRIERS 8150-380-012	107,209.83	$ 72,366.64	100%	$ 72,366.64	
PLANT WIRING & ACCESSORIES,CABLE TRAYS 8150-380-011	1,410,330.47	$ 951,973.07	100%	$ 951,973.07	
PLANT WIRING & ACCESSORIES,CARD KEY ACCESS SYSTEM 8150-380-911	102,167.54	$ 68,963.09	100%	$ 68,963.09	
PLANT WIRING & ACCESSORIES,CONDUIT & TUBING 8150-380-010	1,116,513.19	$ 753,646.40	100%	$ 753,646.40	
PLANT WIRING & ACCESSORIES,ELECTRICAL SYSTEMS 8150-380-999	19,543,101.61	$ 13,191,593.59	100%	$ 13,191,593.59	
PLANT WIRING & ACCESSORIES,ELECTRICAL TESTING 8150-380-017	302,251.19	$ 204,019.55	100%	$ 204,019.55	
PLANT WIRING & ACCESSORIES,EXCAVATION 8150-380-006	602.54	$ 406.71	100%	$ 406.71	
PLANT WIRING & ACCESSORIES,FIRE PROTECTION SYSTEM 8150-380-130	2,957,098.85	$ 1,996,041.72	100%	$ 1,996,041.72	
PLANT WIRING & ACCESSORIES,FIRE-RATED CABLE WRAP SYSTEM 8150-380-005	734,958.87	$ 496,097.24	100%	$ 496,097.24	
PLANT WIRING & ACCESSORIES,GROUND CABLE 8150-380-016	355,050.06	$ 239,658.79	100%	$ 239,658.79	
PLANT WIRING & ACCESSORIES,HEAT TRACING SYSTEM 8150-380-648	90,413.93	$ 61,029.40	100%	$ 61,029.40	
PLANT WIRING & ACCESSORIES,IN-PLANT COMMUNICATION & ALARM 8150-380-125	3,683.44	$ 2,486.32	100%	$ 2,486.32	
PLANT WIRING & ACCESSORIES,LIGHTING AND CONTROLS 8150-380-110	90,010.12	$ 60,756.83	100%	$ 60,756.83	
PLANT WIRING & ACCESSORIES,MAIN CONTROL & ELECTRIC BOARD 8150-380-640	4,956.35	$ 3,345.54	100%	$ 3,345.54	
PLANT WIRING & ACCESSORIES,ROOFS GUTTERS DOWNSPOUTS 8150-380-060	135.68	$ 91.58	100%	$ 91.58	
PLANT WIRING & ACCESSORIES,STRUCTURAL MATERIAL 8150-380-008	7,109.94	$ 4,799.21	100%	$ 4,799.21	
PLANT WIRING & ACCESSORIES,TERMINAL & PULL BOXES 8150-380-013	82,199.90	$ 55,484.93	100%	$ 55,484.93	
PLANT WIRING & ACCESSORIES,UNDISTRIBUTED PROPERTY CHARGE 8150-380-001	1,202,885.67	$ 811,947.83	100%	$ 811,947.83	
PLANT WIRING & ACCESSORIES,WIRE & CABLE 8150-380-014	4,277,515.47	$ 2,887,322.94	25%	$ 721,830.74	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,COMPUTER EQUIPMENT 8150-700-645	16,696.97	$ 11,270.45	0%	$ -	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,FURNITURE AND OFFICE EQUIPMENT 8150-700-100	2,886.32	$ 1,948.27	0%	$ -	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,LABORATORY EQUIPMENT 8150-700-134	58,017.53	$ 39,161.83	0%	$ -	
PROPERTY LOCATED IN THE STATE OF WASHINGTON,SIRENS AND RERP RELATED EQUIPMENT 8150-700-905	464,333.23	$ 313,424.93	0%	$ -	
RADWASTE ANNEX BUILDING,TOOLS AND EQUIPMENT 8150-235-136	3,095.48	$ 2,089.45	100%	$ 2,089.45	Used to store radioactive material.
RADWASTE ANNEX FACILITY,DOMESTIC WATER SYSTEM 8150-225-451	20,212.47	$ 13,643.42	100%	$ 13,643.42	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
RADWASTE ANNEX FACILITY,ELECTRICAL SYSTEM 8150-225-100	30,631.97	$ 20,676.58	100%	$ 20,676.58	
RADWASTE ANNEX FACILITY,EXTERIOR WALLS 8150-225-040	245,951.27	$ 166,017.11	100%	$ 166,017.11	
RADWASTE ANNEX FACILITY,FIRE PROTECTION 8150-225-130	26,106.77	$ 17,622.07	100%	$ 17,622.07	
RADWASTE ANNEX FACILITY,FLOORS AND FLOOR COVERINGS 8150-225-030	79,894.07	$ 53,928.50	100%	$ 53,928.50	
RADWASTE ANNEX FACILITY,HEAT VENTILATING AND AIR CONDITIONING 8150-225-120	106,765.89	$ 72,066.98	100%	$ 72,066.98	
RADWASTE ANNEX FACILITY,HOISTS AND CRANES 8150-225-805	10,365.17	$ 6,996.49	100%	$ 6,996.49	
RADWASTE ANNEX FACILITY,INSTRUMENT RACKS AND PANELS 8150-225-256	2,080.70	$ 1,404.47	100%	$ 1,404.47	
RADWASTE ANNEX FACILITY,INTERIOR WALLS AND CEILINGS 8150-225-050	15,118.00	$ 10,204.65	100%	$ 10,204.65	
RADWASTE ANNEX FACILITY,LIGHTING AND CONTROLS 8150-225-110	66,643.03	$ 44,984.05	100%	$ 44,984.05	
RADWASTE ANNEX FACILITY,PLUMBING 8150-225-090	63,994.28	$ 43,196.14	100%	$ 43,196.14	
RADWASTE ANNEX FACILITY,ROOFS GUTTERS AND DOWNSPOUTS 8150-225-060	211,742.56	$ 142,926.23	100%	$ 142,926.23	
RADWASTE ANNEX FACILITY,STRUCTURAL MATERIAL 8150-225-008	152,469.65	$ 102,917.01	100%	$ 102,917.01	
RADWASTE ANNEX FACILITY,TOOLS AND EQUIPMENT 8150-225-136	161,076.00	$ 108,726.30	100%	$ 108,726.30	
RAINIER COMMUNICATION STA.,COMMUNICATION EQUIPMENT 8150-455-010	4,852.44	$ 3,275.40	100%	$ 3,275.40	Part of the communications system to offsite locals.
REACTOR AUXILIARY BUILDING,480-V AUXILIARY SYSTEM 8150-200-618	84,052.83	$ 56,735.66	100%	$ 56,735.66	The Auxiliary Bldg housed the spent fuel pool cooling system, radioactive waste treatment systems, the radioactive sample (hot) lab, many radioactive components and contaminated areas.
REACTOR AUXILIARY BUILDING,BUILDING FRAME 8150-200-020	3,596,542.20	$ 2,427,665.99	100%	$ 2,427,665.99	
REACTOR AUXILIARY BUILDING,CAPITALIZED INSPECTIONS 8150-200-710	2,109,779.46	$ 1,424,101.14	100%	$ 1,424,101.14	
REACTOR AUXILIARY BUILDING,CARD KEY ACCESS SYSTEM 8150-200-911	245,024.71	$ 165,391.68	100%	$ 165,391.68	
REACTOR AUXILIARY BUILDING,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-200-224	6,021,480.87	$ 4,064,499.59	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,CHEMICAL INJECTION SYSTEM 8150-200-438	25,023.59	$ 16,890.92	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,CIRCULATING WATER SYSTEM 8150-200-435	38,284.20	$ 25,841.84	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,CLEAN RADWASTE TREATMENT SYSTEM 8150-200-250	3,711,879.64	$ 2,505,518.76	100%	$ 2,505,518.76	
REACTOR AUXILIARY BUILDING,CLEAN RADWASTE TREATMENT SYSTEM 8150-200-610	17,128.05	$ 11,561.43	100%	$ 11,561.43	
REACTOR AUXILIARY BUILDING,COMPONENT COOLING WATER SYSTEM 8150-200-216	3,477,286.60	$ 2,347,168.46	50%	$ 1,173,584.23	In service to support the SFP Cooling sys.
REACTOR AUXILIARY BUILDING,CONDENSATE SYSTEM 8150-200-430	160,614.12	$ 108,414.53	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,CONTAINMENT HEAT AND VENT SYSTEM 8150-200-228	69,258.79	$ 46,749.68	100%	$ 46,749.68	
REACTOR AUXILIARY BUILDING,CONTAINMENT SPRAY SYSTEM 8150-200-227	1,380,800.87	$ 932,040.59	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,CRANES & HOISTS 8150-200-805	18,791.54	$ 12,684.29	100%	$ 12,684.29	
REACTOR AUXILIARY BUILDING,DEMINERALIZER SYSTEM 8150-200-243	533,385.96	$ 360,035.52	15%	$ 54,005.33	
REACTOR AUXILIARY BUILDING,DIESEL FUEL OIL SYSTEM 8150-200-626	193,288.09	$ 130,469.46	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,DIRTY RADWASTE TREATMENT SYSTEM 8150-200-251	790,814.51	$ 533,799.79	100%	$ 533,799.79	
REACTOR AUXILIARY BUILDING,DOMESTIC WATER SYSTEM 8150-200-451	43,086.86	$ 29,083.63	100%	$ 29,083.63	
REACTOR AUXILIARY BUILDING,EXCAVATION 8150-200-006	360,920.16	$ 243,621.11	100%	$ 243,621.11	
REACTOR AUXILIARY BUILDING,EXTERIOR WALLS 8150-200-040	659,882.76	$ 445,420.86	100%	$ 445,420.86	
REACTOR AUXILIARY BUILDING,EXTRACTION STEAM SYSTEM 8150-200-423	101,640.26	$ 68,607.18	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,FIRE PROTECTION EQUIPMENT 8150-200-130	2,178,870.97	$ 1,470,737.90	100%	$ 1,470,737.90	
REACTOR AUXILIARY BUILDING,FIXED AREA RADIATION MONITOR SYSTEM 8150-200-260	546,170.57	$ 368,665.13	100%	$ 368,665.13	
REACTOR AUXILIARY BUILDING,FLOORS AND FLOOR COVERINGS 8150-200-030	123,265.46	$ 83,204.19	100%	$ 83,204.19	
REACTOR AUXILIARY BUILDING,FOUNDATION AND BASE SLAB 8150-200-010	1,489,188.11	$ 1,005,201.97	100%	$ 1,005,201.97	
REACTOR AUXILIARY BUILDING,FUEL HANDLING AND STORAGE EQUIPMENT 8150-200-231	19,913.05	$ 13,441.31	100%	$ 13,441.31	
REACTOR AUXILIARY BUILDING,FURNITURE & OFFICE EQUIPMENT 8150-200-100	176.23	$ 118.96	100%	$ 118.96	
REACTOR AUXILIARY BUILDING,GASEOUS RADWASTE TREATMENT SYSTEM 8150-200-252	2,876,838.76	$ 1,941,866.16	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-200-120	2,061,078.12	$ 1,391,227.73	100%	$ 1,391,227.73	
REACTOR AUXILIARY BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-200-425	388,378.33	$ 262,155.37	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-200-810	1,512,385.02	$ 1,020,859.89	30%	$ 306,257.97	
REACTOR AUXILIARY BUILDING,INSTRUMENTS RACKS AND PANELS 8150-200-200	7,899.17	$ 5,331.94	30%	$ 1,599.58	
REACTOR AUXILIARY BUILDING,INSTRUMENTS RACKS AND PANELS 8150-200-256	6,185,985.29	$ 4,175,540.07	30%	$ 1,252,662.02	
REACTOR AUXILIARY BUILDING,INSTRUMENTS RACKS AND PANELS 8150-200-460	10,258.17	$ 6,924.26	30%	$ 2,077.28	
REACTOR AUXILIARY BUILDING,INTERIOR WALLS AND CEILINGS 8150-200-050	4,254,158.76	$ 2,871,557.16	100%	$ 2,871,557.16	
REACTOR AUXILIARY BUILDING,LAB EQUIPMENT 8150-200-134	82,364.17	$ 55,595.81	100%	$ 55,595.81	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
REACTOR AUXILIARY BUILDING,LADDERS AND STAIRWAYS 8150-200-013	256,438.49	$ 173,095.98	100%	$ 173,095.98	
REACTOR AUXILIARY BUILDING,LIGHTING AND CONTROLS 8150-200-110	213,541.70	$ 144,140.65	100%	$ 144,140.65	
REACTOR AUXILIARY BUILDING,MAIN STEAM SYSTEM 8150-200-420	697,381.16	$ 470,732.28	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,MAKE-UP WATER TREATMENT SYSTEM 8150-200-446	73,518.56	$ 49,625.03	100%	$ 49,625.03	Used to support CCW and SFP
REACTOR AUXILIARY BUILDING,MISC GAS SUPPLY SYSTEM 8150-200-815	2,347,470.64	$ 1,584,542.68	50%	$ 792,271.34	Nitrogen sys. For CCW and SFP doors
REACTOR AUXILIARY BUILDING,NUCLEAR INSTRUMENTATION SYSTEM 8150-200-263	4,339.53	$ 2,929.18	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,PLUMBING 8150-200-090	1,055,521.51	$ 712,477.02	100%	$ 712,477.02	
REACTOR AUXILIARY BUILDING,POWER SYSTEMS 8150-200-265	136,035.40	$ 91,823.90	100%	$ 91,823.90	
REACTOR AUXILIARY BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-200-225	463,660.63	$ 312,970.93	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-200-245	293,661.33	$ 198,221.40	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-200-262	3,648,439.86	$ 2,462,696.91	100%	$ 2,462,696.91	
REACTOR AUXILIARY BUILDING,PROCESS SAMPLING SYSTEM 8150-200-267	2,017,661.33	$ 1,361,921.40	30%	$ 408,576.42	
REACTOR AUXILIARY BUILDING,PROCESS SAMPLING SYSTEM 8150-200-670	4,443.27	$ 2,999.21	30%	$ 899.76	
REACTOR AUXILIARY BUILDING,PROCESS STEAM SYSTEM 8150-200-422	721,121.51	$ 486,757.02	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,REACTOR AUXILIARY HEAT AND VENT SYSTEM 8150-200-230	70,428.34	$ 47,539.13	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,REACTOR COOLANT SYSTEM 8150-200-221	1,044,521.59	$ 705,052.07	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,RESIDUAL HEAT REMOVAL SYSTEM 8150-200-215	3,396,554.62	$ 2,292,674.37	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-200-060	148,823.66	$ 100,455.97	100%	$ 100,455.97	
REACTOR AUXILIARY BUILDING,SAFETY INJECTION SYSTEM 8150-200-214	3,795,390.06	$ 2,561,888.29	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,SERVICE WATER SYSTEM 8150-200-440	3,258,322.92	$ 2,199,367.97	30%	$ 659,810.39	
REACTOR AUXILIARY BUILDING,SOLID RADWASTE TREATMENT SYSTEM 8150-200-253	221,984.66	$ 149,839.65	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,SPENT FUEL POOL COOLING SYSTEM 8150-200-233	1,587,028.72	$ 1,071,244.39	100%	$ 1,071,244.39	
REACTOR AUXILIARY BUILDING,STEAM GENERATOR BLOWDOWN SYSTEM 8150-200-254	1,036,420.47	$ 699,583.82	0%	$ -	Not used.
REACTOR AUXILIARY BUILDING,STRUCTURAL MATERIAL 8150-200-008	489,342.66	$ 330,306.30	100%	$ 330,306.30	
REACTOR AUXILIARY BUILDING,TOOLS AND EQUIPMENT 8150-200-136	88,663.17	$ 59,847.64	100%	$ 59,847.64	
REACTOR CONTAINMENT,120-V AC INSTRUMENT SYSTEM 8150-160-630	35,446.92	$ 23,926.67	100%	$ 23,926.67	
REACTOR CONTAINMENT,480-V AUXILIARY SYSTEM 8150-160-618	54,860.05	$ 37,030.53	100%	$ 37,030.53	
REACTOR CONTAINMENT,CARD KEY ACCESS SYSTEM 8150-160-911	16,510.41	$ 11,144.53	100%	$ 11,144.53	
REACTOR CONTAINMENT,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-160-224	2,315,521.21	$ 1,562,976.82	0%	$ -	
REACTOR CONTAINMENT,CLEAN RADWASTE TREATMENT SYSTEM 8150-160-250	616,810.03	$ 416,346.77	0%	$ -	
REACTOR CONTAINMENT,COMPONENT COOLING WATER SYSTEM 8150-160-216	5,678,663.94	$ 3,833,098.16	0%	$ -	
REACTOR CONTAINMENT,CONTAINMENT FLOORS AND WALKWAYS 8150-160-030	1,658,666.92	$ 1,119,600.17	100%	$ 1,119,600.17	
REACTOR CONTAINMENT,CONTAINMENT HEAT AND VENT SYSTEM 8150-160-228	1,247,793.63	$ 842,260.70	100%	$ 842,260.70	
REACTOR CONTAINMENT,CONTAINMENT PENETRATIONS 8150-160-229	1,395,881.38	$ 942,219.93	100%	$ 942,219.93	
REACTOR CONTAINMENT,CONTAINMENT SPRAY SYSTEM 8150-160-227	3,280,319.80	$ 2,214,215.87	0%	$ -	
REACTOR CONTAINMENT,CONTAINMENT SUPERSTRUCTURE 8150-160-020	13,627,370.32	$ 9,198,474.97	100%	$ 9,198,474.97	
REACTOR CONTAINMENT,CRANES & HOISTS 8150-160-805	1,600,664.35	$ 1,080,448.44	100%	$ 1,080,448.44	
REACTOR CONTAINMENT,DEMINERALIZER SYSTEM 8150-160-243	22,847.57	$ 15,422.11	0%	$ -	
REACTOR CONTAINMENT,DIRTY RADWASTE TREATMENT SYSTEM 8150-160-251	371,326.64	$ 250,645.48	100%	$ 250,645.48	Containment drains still inservice
REACTOR CONTAINMENT,ELECTRICAL PENETRATIONS 8150-160-010	4,733,329.29	$ 3,194,997.27	100%	$ 3,194,997.27	
REACTOR CONTAINMENT,EXCAVATION 8150-160-006	97,918.85	$ 66,095.22	100%	$ 66,095.22	
REACTOR CONTAINMENT,FEEDWATER SYSTEM 8150-160-431	1,386,793.98	$ 936,085.94	0%	$ -	
REACTOR CONTAINMENT,FIRE PROTECTION EQUIPMENT 8150-160-130	367,151.57	$ 247,827.31	100%	$ 247,827.31	
REACTOR CONTAINMENT,FIXED AREA RADIATION MONITOR SYSTEM 8150-160-260	9,861.89	$ 6,656.78	0%	$ -	
REACTOR CONTAINMENT,FUEL HANDLING AND STORAGE EQUIPMENT 8150-160-231	188,547.49	$ 127,269.56	0%	$ -	The fuel was removed from the containment bldg.
REACTOR CONTAINMENT,GASEOUS RADWASTE TREATMENT SYSTEM 8150-160-252	612,780.55	$ 413,626.87	0%	$ -	
REACTOR CONTAINMENT,HEAT VENTILATING AND AIR CONDITIONING 8150-160-120	5,329,118.03	$ 3,597,154.67	100%	$ 3,597,154.67	
REACTOR CONTAINMENT,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-160-425	89,979.97	$ 60,736.48	100%	$ 60,736.48	
REACTOR CONTAINMENT,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-160-125	17,432.93	$ 11,767.23	100%	$ 11,767.23	
REACTOR CONTAINMENT,INSTRUMENT & SERVICE AIR SYSTEM 8150-160-810	1,285,957.27	$ 868,021.16	100%	$ 868,021.16	System in service to support decom. Act.
REACTOR CONTAINMENT,INSTRUMENTATION AND CONTROL 8150-160-261	3,117,089.79	$ 2,104,035.61	0%	$ -	
REACTOR CONTAINMENT,INSTRUMENTS RACKS AND PANELS 8150-160-256	969,403.80	$ 654,347.57	0%	$ -	
REACTOR CONTAINMENT,INSTRUMENTS RACKS AND PANELS 8150-160-460	13,588.94	$ 9,172.53	0%	$ -	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
REACTOR CONTAINMENT,INTEGRATED LEAK RATE TESTING SYSTEM 8150-160-257	21,581.55 $	14,567.55	0% $	-	
REACTOR CONTAINMENT,INTERIOR WALLS AND DOME 8150-160-035	388,126.19 $	261,985.18	100% $	261,985.18	
REACTOR CONTAINMENT,LAB EQUIPMENT 8150-160-134	65,153.95 $	43,978.92	0% $	-	
REACTOR CONTAINMENT,LADDERS AND STAIRWAYS 8150-160-013	637,458.42 $	430,284.43	100% $	430,284.43	
REACTOR CONTAINMENT,LIGHTING AND CONTROL 8150-160-110	471,626.97 $	318,348.20	100% $	318,348.20	
REACTOR CONTAINMENT,MAIN STEAM SYSTEM 8150-160-420	4,360,259.63 $	2,943,175.25	0% $	-	
REACTOR CONTAINMENT,MAKE-UP WATER TREATMENT SYSTEM 8150-160-446	169,988.66 $	114,742.35	100% $	114,742.35	Still in service to support decom. Act.
REACTOR CONTAINMENT,MISC GAS SUPPLY SYSTEM 8150-160-815	89,710.72 $	60,554.74	0% $	-	
REACTOR CONTAINMENT,MISCELLANEOUS REACTOR PLANT INSTRUMENT EQUIPMENT 8150-160-269	45,096.35 $	30,440.04	0% $	-	
REACTOR CONTAINMENT,NUCLEAR INSTRUMENTATION SYSTEM 8150-160-263	4,243,271.09 $	2,864,207.99	0% $	-	
REACTOR CONTAINMENT,PLUMBING 8150-160-090	13,475.57 $	9,096.01	0% $	-	
REACTOR CONTAINMENT,PRIMARY MAKE-UP WATER SYSTEM 8150-160-225	114,796.42 $	77,487.58	0% $	-	
REACTOR CONTAINMENT,PRIMARY MAKE-UP WATER SYSTEM 8150-160-245	52,040.46 $	35,127.31	0% $	-	
REACTOR CONTAINMENT,PROCESS RADIATION MONITOR SYSTEM 8150-160-262	1,245,205.10 $	840,513.44	50% $	420,256.72	PERM-1 for effluent monitoring
REACTOR CONTAINMENT,PROCESS SAMPLING SYSTEM 8150-160-267	1,453,061.34 $	980,816.40	0% $	-	
REACTOR CONTAINMENT,REACTOR CONTROL AND PROTECTION SYSTEM 8150-160-264	84,618.18 $	57,117.27	0% $	-	
REACTOR CONTAINMENT,REACTOR CONTROLS 8150-160-212	5,779,344.57 $	3,901,057.58	0% $	-	
REACTOR CONTAINMENT,REACTOR COOLANT SYSTEM 8150-160-221	22,733,053.44 $	15,344,811.07	0% $	-	
REACTOR CONTAINMENT,RESIDUAL HEAT REMOVAL SYSTEM 8150-160-215	2,485,200.92 $	1,677,510.62	0% $	-	
REACTOR CONTAINMENT,ROOFS GUTTERS DOWNSPOUTS 8150-160-060	22,053.59 $	14,886.17	100% $	14,886.17	
REACTOR CONTAINMENT,SAFETY INJECTION SYSTEM 8150-160-214	4,842,038.91 $	3,268,376.26	0% $	-	
REACTOR CONTAINMENT,SERVICE WATER SYSTEM 8150-160-440	360.21 $	243.14	0% $	-	
REACTOR CONTAINMENT,SPENT FUEL POOL COOLING SYSTEM 8150-160-233	289,019.40 $	195,088.10	0% $	-	
REACTOR CONTAINMENT,STEAM GENERATOR BLOWDOWN SYSTEM 8150-160-254	1,534,601.30 $	1,035,855.88	0% $	-	
REACTOR CONTAINMENT,STORES EQUIPMENT 8150-160-138	195.49 $	131.96	0% $	-	
REACTOR CONTAINMENT,STRUCTURAL MATERIAL 8150-160-008	1,133,830.86 $	765,335.83	100% $	765,335.83	
REACTOR CONTAINMENT,TOOLS & EQUIPMENT 8150-160-136	557,267.59 $	376,155.62	25% $	94,038.91	Some tools, equipment and fixtires were needed for decommissioning the Reactor Vessel and other components.
REACTOR CONTAINMENT,TOOLS EQUIPMENT AND FIXTURES 8150-160-232	1,425,580.09 $	962,266.56	25% $	240,566.64	
REACTOR CONTAINMENT,TRANSPORTATION-AUXILIARY COMPONENTS 8150-160-296	1,078,085.56 $	727,707.75	0% $	-	
REACTOR CONTAINMENT,UNDISTRIBUTED PROPERTY CHARGE 8150-160-001	2,992,178.90 $	2,019,720.76	0% $	-	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),BUILDING FRAME 8150-435-020	35,846.58 $	24,196.44	100% $	24,196.44	This area was used to during the asset recovery process, store hazardous non-radioactive material and was later used to process and ship slightly contaminated concrete.
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),CABINETS SHELVES AND COUNTERS 8150-435-140	10,473.37 $	7,069.52	0% $	-	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),ELECTRICAL SYSTEM 8150-435-100	5,101.25 $	3,443.34	100% $	3,443.34	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),FENCING 8150-435-175	4,395.06 $	2,966.67	100% $	2,966.67	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),FLOOR AND FLOOR COVERINGS 8150-435-030	4,503.26 $	3,039.70	100% $	3,039.70	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),INTERIOR WALLS AND CEILINGS 8150-435-050	10,602.74 $	7,156.85	0% $	-	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),LIGHTING AND CONTROLS 8150-435-110	943.48 $	636.85	100% $	636.85	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),MISCELLANEOUS BUILDING EQUIPMENT 8150-435-199	50,432.00 $	34,041.60	100% $	34,041.60	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),PLUMBING 8150-435-090	35,395.81 $	23,892.17	100% $	23,892.17	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),ROADWAYS AND PARKING 8150-435-031	86,922.83 $	58,672.91	100% $	58,672.91	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),STOREROOM EQUIPMENT 8150-435-138	12,191.10 $	8,228.99	100% $	8,228.99	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),TEMPORARY STORAGE OF CHEMICAL WASTE 8150-435-180	44,011.17 $	29,707.54	100% $	29,707.54	
RECEIVING WAREHOUSE (FORMER PEBBLE SPRINGS),TOOLS & EQUIPMENT 8150-435-136	9,935.31 $	6,706.33	100% $	6,706.33	
RECONCILIATION ADJUSTMENT,ADJUSTMENTS 8150-018-013	(60,662.37) $	(40,947.10)	100% $	(40,947.10)	
RECREATION FACILITIES,FURNITURE & OFFICE EQUIPMENT 8150-060-610	13,141.56 $	8,870.55	0% $	-	The recreation area was used, but it was for the enjoyment of the public rather than the safety of the public.
RECREATION FACILITIES,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-060-125	1,340.26 $	904.68	100% $	904.68	
RECREATION FACILITIES,MAINTENANCE BUILDING 8150-060-280	185,725.96 $	125,365.02	100% $	125,365.02	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
RECREATION FACILITIES,MODELS DISPLAYS & FILMS 8150-060-600	28,943.64	$ 19,536.96	0%	$ -	VIC shutdown
RECREATION FACILITIES,OUTSIDE FACILITIES 8150-060-006	1,250.98	$ 844.41	100%	$ 844.41	
RECREATION FACILITIES,PICNIC SHELTER 1 8150-060-260	117,155.02	$ 79,079.64	100%	$ 79,079.64	
RECREATION FACILITIES,PICNIC SHELTER 2 8150-060-262	117,155.06	$ 79,079.67	100%	$ 79,079.67	
RECREATION FACILITIES,RECREATION AND PICNIC AREAS 8150-060-200	1,709,599.89	$ 1,153,979.93	100%	$ 1,153,979.93	
RECREATION FACILITIES,RECREATION AREA EQUIPMENT 8150-060-700	1,784.67	$ 1,204.65	100%	$ 1,204.65	
RECREATION FACILITIES,RECREATION AREA OFFICE BUILDING 8150-060-210	31,582.40	$ 21,318.12	100%	$ 21,318.12	
RECREATION FACILITIES,REFLECTING LAKE 8150-060-010	304,285.82	$ 205,392.93	100%	$ 205,392.93	
RECREATION FACILITIES,RESTROOM 1 8150-060-250	75,994.17	$ 51,296.06	100%	$ 51,296.06	
RECREATION FACILITIES,RESTROOM 2 8150-060-252	75,994.15	$ 51,296.05	100%	$ 51,296.05	
RECREATION FACILITIES,SECURITY EQUIPMENT 8150-060-123	1,889.78	$ 1,275.60	100%	$ 1,275.60	security-related
RECREATION FACILITIES,TOOLS & EQUIPMENT 8150-060-136	25,847.85	$ 17,447.30	100%	$ 17,447.30	
RECREATION FACILITIES,TRAFFIC CONTROL BOOTH 8150-060-270	29,157.30	$ 19,681.18	0%	$ -	Building not used
RECREATION FACILITIES,WILDLIFE VIEWING SHELTER 8150-060-290	146,499.40	$ 98,887.10	0%	$ -	
SECURITY BUILDING-WEST,BUILDING COMMUNICATIONS WIRING/EQUIP 8150-075-130	3,194.55	$ 2,156.32	100%	$ 2,156.32	
SECURITY BUILDING-WEST,BUILDING ELECTRICAL 8150-075-100	221,432.87	$ 149,467.19	100%	$ 149,467.19	
SECURITY BUILDING-WEST,BUILDING FRAME 8150-075-020	84,656.72	$ 57,143.29	100%	$ 57,143.29	Protect the public from security-related threats.
SECURITY BUILDING-WEST,BUILDING LIGHTING 8150-075-110	50,126.76	$ 33,835.56	100%	$ 33,835.56	
SECURITY BUILDING-WEST,BUILDING PLUMBING 8150-075-090	68,795.48	$ 46,436.95	100%	$ 46,436.95	
SECURITY BUILDING-WEST,CABINETS, SHELVES & COUNTERS 8150-075-140	2,652.17	$ 1,790.21	100%	$ 1,790.21	
SECURITY BUILDING-WEST,EXTERIOR WALLS 8150-075-040	236,680.44	$ 159,759.30	100%	$ 159,759.30	
SECURITY BUILDING-WEST,FLOOR & FLOOR COVERINGS 8150-075-030	125,608.01	$ 84,785.41	100%	$ 84,785.41	
SECURITY BUILDING-WEST,FOUNDATION & BASE SLAB 8150-075-010	127,141.45	$ 85,820.48	100%	$ 85,820.48	
SECURITY BUILDING-WEST,HEAT, VENTILATING & AIR CONDITIONING 8150-075-120	129,588.79	$ 87,472.43	100%	$ 87,472.43	
SECURITY BUILDING-WEST,INTERIOR WALLS & CEILINGS 8150-075-050	277,070.60	$ 187,022.66	100%	$ 187,022.66	
SECURITY BUILDING-WEST,LABRATORY EQUIPMENT 8150-075-500	261,726.02	$ 176,665.06	100%	$ 176,665.06	
SECURITY BUILDING-WEST,ROOFING, GUTTERS, & DOWNSPOUTS 8150-075-060	75,675.03	$ 51,080.65	100%	$ 51,080.65	
SECURITY BUILDING-WEST,SECURITY EQUIPMENT 8150-075-123	907,256.85	$ 612,398.37	100%	$ 612,398.37	
SECURITY BUILDING-WEST,TEMPORARY FENCING & SECURITY EQUIPMENT 8150-075-001	11,775.55	$ 7,948.50	100%	$ 7,948.50	
SIMULATOR TRAINING FACILITY,BUILDING FRAME 8150-115-020	729,261.13	$ 492,251.26	100%	$ 492,251.26	
SIMULATOR TRAINING FACILITY,CABINETS, SHELVES AND COUNTERS 8150-115-140	91,286.27	$ 61,618.23	5%	$ 3,080.91	The training Bldg was used later on for training during decommissioning, LCR project, to support large plant meetings, and the ISFSI project (in particular for welder training.
SIMULATOR TRAINING FACILITY,CABLE TRAYS 8150-115-011	92,589.76	$ 62,498.09	100%	$ 62,498.09	
SIMULATOR TRAINING FACILITY,COMMUNICATION EQUIPMENT 8150-115-010	295,428.57	$ 199,414.28	100%	$ 199,414.28	
SIMULATOR TRAINING FACILITY,COMMUNICATION EQUIPMENT-INTERSITE ONLY. 8150-115-125	27,569.17	$ 18,609.19	100%	$ 18,609.19	
SIMULATOR TRAINING FACILITY,COMPUTER EQUIPMENT-(TO CLOSE 89--ITMS S/B TRNSFRD) 8150-115-645	192,040.14	$ 129,627.09	0%	$ -	
SIMULATOR TRAINING FACILITY,ELEVATORS 8150-115-144	53,835.15	$ 36,338.73	100%	$ 36,338.73	
SIMULATOR TRAINING FACILITY,EXTERIOR WALLS 8150-115-040	809,560.04	$ 546,453.03	100%	$ 546,453.03	
SIMULATOR TRAINING FACILITY,FIRE PROTECTION EQUIPMENT 8150-115-130	338,613.27	$ 228,563.96	100%	$ 228,563.96	
SIMULATOR TRAINING FACILITY,FLOORS AND FLOOR COVERINGS 8150-115-030	467,592.14	$ 315,624.69	5%	$ 15,781.23	
SIMULATOR TRAINING FACILITY,FURNITURE AND OFFICE EQUIPMENT 8150-115-100	1,150,500.43	$ 776,587.79	5%	$ 38,829.39	
SIMULATOR TRAINING FACILITY,HEATING, VENTILATING & AIR CONDITIONING 8150-115-120	1,208,642.92	$ 815,833.97	100%	$ 815,833.97	
SIMULATOR TRAINING FACILITY,HOISTS AND CRANES 8150-115-805	47,311.71	$ 31,935.40	100%	$ 31,935.40	
SIMULATOR TRAINING FACILITY,INSTRUMENTS RACKS AND PANELS 8150-115-460	152,390.98	$ 102,863.91	5%	$ 5,143.20	
SIMULATOR TRAINING FACILITY,INTERIOR WALLS AND CEILINGS 8150-115-050	679,955.30	$ 458,969.83	100%	$ 458,969.83	
SIMULATOR TRAINING FACILITY,LABORATORY EQUIPMENT 8150-115-500	364,162.05	$ 245,809.38	5%	$ 12,290.47	
SIMULATOR TRAINING FACILITY,MAINTENANCE BUILDING 8150-115-280	11,964.35	$ 8,075.94	5%	$ 403.80	
SIMULATOR TRAINING FACILITY,ROADS, ROADWAYS, AND PARKING LOTS 8150-115-035	195,810.00	$ 132,171.75	100%	$ 132,171.75	
SIMULATOR TRAINING FACILITY,ROOFING, GUTTERS, DOWNSPOUTS 8150-115-060	348,856.53	$ 235,478.16	100%	$ 235,478.16	
SIMULATOR TRAINING FACILITY,SECURITY EQUIPMENT 8150-115-123	41,122.88	$ 27,757.94	100%	$ 27,757.94	
SIMULATOR TRAINING FACILITY,TOOLS AND EQUIPMENT 8150-115-136	783.75	$ 529.03	5%	$ 26.45	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
SPARE PARTS,120-V AC INSTRUMENT SYSTEM 8150-600-630	17,094.85	$ 11,539.02	100%	$ 11,539.02	Some spare parts were needed for maintenance, decommissioning and the ISFSI project.
SPARE PARTS,480-V SWITCHGEAR 8150-600-618	521.12	$ 351.76	100%	$ 351.76	
SPARE PARTS,COMMUNICATION EQUIPMENT 8150-600-010	1,910.82	$ 1,289.80	100%	$ 1,289.80	
SPARE PARTS,FIRE PROTECTION EQUIPMENT 8150-600-130	1,455.34	$ 982.35	100%	$ 982.35	
SPARE PARTS,LAB EQUIPMENT 8150-600-134	967.79	$ 653.26	100%	$ 653.26	
SPARE PARTS,MAIN CONTROL & ELECTRIC BOARD 8150-600-640	49,916.92	$ 33,693.92	30%	$ 10,108.18	
SPARE PARTS,REACTOR CONTROLS 8150-600-212	9,967.13	$ 6,727.81	0%	$ -	
SPARE PARTS,REACTOR COOLANT SYSTEM 8150-600-221	14,620.57	$ 9,868.88	0%	$ -	
SPARE PARTS,SECURITY EQUIPMENT 8150-600-120	9,102.62	$ 6,144.27	100%	$ 6,144.27	
SPARE PARTS,SNUBBERS 8150-600-063	163,242.69	$ 110,188.82	0%	$ -	
STEAM GENERATOR BLOWDOWN BUILDING,BUILDING FRAME 8150-430-020	170,715.21	$ 115,232.77	100%	$ 115,232.77	Building contained radioactive contaminated material
STEAM GENERATOR BLOWDOWN BUILDING,ELECTRICAL SYSTEM 8150-430-100	910,654.12	$ 614,691.53	0%	$ -	
STEAM GENERATOR BLOWDOWN BUILDING,FENCING 8150-430-175	6,015.37	$ 4,060.37	0%	$ -	
STEAM GENERATOR BLOWDOWN BUILDING,FOUNDATION 8150-430-010	64,122.32	$ 43,282.57	100%	$ 43,282.57	
STEAM GENERATOR BLOWDOWN BUILDING,HEAT VENTILATION AND AIR CONDITIONING 8150-430-120	20,729.47	$ 13,992.39	0%	$ -	
STEAM GENERATOR BLOWDOWN BUILDING,IN-PLANT COMMUNICATIONS EQUIP. 8150-430-125	1,651.93	$ 1,115.05	0%	$ -	
STEAM GENERATOR BLOWDOWN BUILDING,LIGHTING AND CONTROLS 8150-430-110	48,215.80	$ 32,545.67	0%	$ -	
STEAM GENERATOR BLOWDOWN BUILDING,STEAM GENERATOR BLOWDOWN SYSTEM 8150-430-254	5,392,160.63	$ 3,639,708.43	0%	$ -	
STEAM GENERATOR BLOWDOWN BUILDING,TOOLS AND EQUIPMENT 8150-430-136	25,304.51	$ 17,080.54	0%	$ -	
SULFURIC ACID STORAGE TANK BUILDING,CIRCULATING WATER SYSTEM 8150-370-435	316,095.28	$ 213,364.31	0%	$ -	Not used.
SULFURIC ACID STORAGE TANK BUILDING,DOMESTIC WATER SYSTEM 8150-370-451	11,470.39	$ 7,742.51	0%	$ -	
SULFURIC ACID STORAGE TANK BUILDING,ELECTICAL SYSTEM 8150-370-100	2,581.74	$ 1,742.67	0%	$ -	
SULFURIC ACID STORAGE TANK BUILDING,LIGHTING 8150-370-110	10,200.91	$ 6,885.61	0%	$ -	
SULFURIC ACID STORAGE TANK BUILDING,ROADWAYS AND PARKING 8150-370-030	31,962.13	$ 21,574.44	0%	$ -	
SWITCHYARD,230-KV ALLSTON BPA #1 LINE 8150-120-154	55,337.33	$ 37,352.70	100%	$ 37,352.70	The Switchyard was necessary for power supply to the plant, and continues to be the interface between PGE and BPA at Alston.
SWITCHYARD,230-KV ALLSTON BPA #2 LINE 8150-120-156	96,604.85	$ 65,208.27	100%	$ 65,208.27	
SWITCHYARD,230-KV BUS TIE V-81-82 8150-120-111	68,203.08	$ 46,037.08	100%	$ 46,037.08	
SWITCHYARD,230-KV BUS TIE V-81-85 8150-120-113	22,889.86	$ 15,450.66	100%	$ 15,450.66	
SWITCHYARD,230-KV BUS TIE V-82-85 8150-120-114	111,162.07	$ 75,034.40	100%	$ 75,034.40	
SWITCHYARD,230-KV BUS V-81 8150-120-110	169,678.12	$ 114,532.73	100%	$ 114,532.73	
SWITCHYARD,230-KV BUS V-82 8150-120-112	102,433.31	$ 69,142.48	100%	$ 69,142.48	
SWITCHYARD,230-KV DEAD-END TOWER 8150-120-080	530,791.03	$ 358,283.95	100%	$ 358,283.95	
SWITCHYARD,230-KV RIVERGATE LINE 8150-120-150	26,647.12	$ 17,986.81	100%	$ 17,986.81	
SWITCHYARD,230-KV ST MARYS LINE 8150-120-152	55,272.25	$ 37,308.77	100%	$ 37,308.77	
SWITCHYARD,A-C STATION SERVICE 8150-120-300	26,734.41	$ 18,045.73	100%	$ 18,045.73	
SWITCHYARD,BUILDING FOUNDATION AND FLOORS 8150-120-020	81,876.05	$ 55,266.33	100%	$ 55,266.33	
SWITCHYARD,COMMUNICATION EQUIPMENT 8150-120-010	512,665.83	$ 346,049.44	100%	$ 346,049.44	
SWITCHYARD,CONDUIT & COPE TRAY 8150-120-220	1,928.60	$ 1,301.81	100%	$ 1,301.81	
SWITCHYARD,CONTROL HOUSE BUILDING 8150-120-070	111,048.26	$ 74,957.58	100%	$ 74,957.58	
SWITCHYARD,CRUSHED ROCK SURFACING 8150-120-012	73,016.04	$ 49,285.83	100%	$ 49,285.83	
SWITCHYARD,DC POWER SUPPLY-MICROWAVE 8150-120-700	10,560.68	$ 7,128.46	100%	$ 7,128.46	
SWITCHYARD,D-C STATION SERVICE 8150-120-305	13,968.39	$ 9,428.66	100%	$ 9,428.66	
SWITCHYARD,FENCING 8150-120-175	17,376.73	$ 11,729.29	100%	$ 11,729.29	
SWITCHYARD,GROUND GRID 8150-120-670	36,414.49	$ 24,579.78	100%	$ 24,579.78	
SWITCHYARD,HEATING VENTILATING & AIR CONDITIONING 8150-120-120	230.76	$ 155.76	100%	$ 155.76	
SWITCHYARD,MAIN TRANSFORMER UNIT 1 8150-120-090	1,645,634.84	$ 1,110,803.52	0%	$ -	Plant transformer not likely to be used.
SWITCHYARD,MICROWAVE PANEL EQUIPMENT 8150-120-100	25,298.24	$ 17,076.31	100%	$ 17,076.31	
SWITCHYARD,MISCELLANEOUS 8150-120-990	473,900.99	$ 319,883.17	100%	$ 319,883.17	
SWITCHYARD,OIL CIRCUIT BREAKERS 8150-120-401	559,296.31	$ 377,525.01	100%	$ 377,525.01	
SWITCHYARD,RELAY & SWITCH PANELS 8150-120-208	248,900.34	$ 168,007.73	100%	$ 168,007.73	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
SWITCHYARD,START-UP TRANSFORMERS 8150-120-611	420,860.41	$ 284,080.78	100%	$ 284,080.78	Startup transformers still in service to supply the plant
SWITCHYARD,TELEMETERING EQUIPMENT 8150-120-209	145,786.13	$ 98,405.64	100%	$ 98,405.64	
SWITCHYARD,UNDERGROUND CONDUIT & DUCTS 8150-120-510	133,284.80	$ 89,967.24	100%	$ 89,967.24	
SWITCHYARD,VAULTS HANDHOLES & MANHOLES 8150-120-512	40,838.37	$ 27,565.90	100%	$ 27,565.90	
SWITCHYARD,YARD LOOP DISTRIBUTION SYSTEM 8150-120-490	630.72	$ 425.74	100%	$ 425.74	
SYSTEM CONTROL CENTER,COMMUNICATION EQUIPMENT 8150-450-010	33,407.54	$ 22,550.09	100%	$ 22,550.09	
TECHNICAL SUPPORT CENTER,CARD KEY ACCESS SYSTEM 8150-462-911	625,502.78	$ 422,214.38	100%	$ 422,214.38	The Technical Support Center housed some security equipment, records vault for NRC-required records, the contract labor force for decommissioning, and is now the ISFSI headquarters.
TECHNICAL SUPPORT CENTER,COMMUNICATIONS EQUIPMENT 8150-462-010	2,037,890.57	$ 1,375,576.13	100%	$ 1,375,576.13	
TECHNICAL SUPPORT CENTER,COMPUTER EQUIPMENT 8150-462-645	3,004,113.50	$ 2,027,776.61	0%	$ -	Not used.
TECHNICAL SUPPORT CENTER,FIRE PROTECTION SYSTEM 8150-462-130	3,019.12	$ 2,037.91	100%	$ 2,037.91	
TECHNICAL SUPPORT CENTER,FIXED AREA RADIATION MONITOR SYSTEM 8150-462-260	193,697.65	$ 130,745.91	0%	$ -	
TECHNICAL SUPPORT CENTER,FURNITURE AND OFFICE EQUIPMENT 8150-462-100	1,224,114.67	$ 826,277.40	0%	$ -	
TECHNICAL SUPPORT CENTER,HEAT VENTILATING AND AIR CONDITIONING 8150-462-120	726,254.34	$ 490,221.68	100%	$ 490,221.68	
TECHNICAL SUPPORT CENTER,IN-PLANT COMMUNICATION EQUIP 8150-462-125	10,263.74	$ 6,928.02	100%	$ 6,928.02	
TECHNICAL SUPPORT CENTER,INTERIOR WALLS AND CEILINGS 8150-462-050	137,848.47	$ 93,047.72	100%	$ 93,047.72	
TECHNICAL SUPPORT CENTER,STRUCTURAL MATERIAL 8150-462-008	389,319.96	$ 262,790.97	100%	$ 262,790.97	
TRAILERS/MODULAR BUILDINGS,COMMUNICATION EQUIPMENT 8150-325-010	2,109.90	$ 1,424.18	0%	$ -	
TURBINE-GENERATOR BUILDING,12.5-KV AUXILIARY SYSTEM 8150-240-616	364,269.24	$ 245,881.74	100%	$ 245,881.74	
TURBINE-GENERATOR BUILDING,4160-V AUXILIARY SYSTEM 8150-240-617	1,094,472.50	$ 738,768.94	100%	$ 738,768.94	Turbine Building contained electrical switchgear rooms, fire protection, plant air system compressors, and water systems. Structures also contained asbestos containing material and some equipment was potential contaminated until the Final Survey was completed
TURBINE-GENERATOR BUILDING,480-V AUXILIARY SYSTEM 8150-240-618	622,387.66	$ 420,111.67	100%	$ 420,111.67	
TURBINE-GENERATOR BUILDING,ALTERREX EXCITOR SYSTEM 8150-240-415	361,754.02	$ 244,183.96	0%	$ -	
TURBINE-GENERATOR BUILDING,AUXILIARY FEEDWATER SYSTEM 8150-240-432	4,016,586.07	$ 2,711,195.60	0%	$ -	
TURBINE-GENERATOR BUILDING,AUXILIARY STEAM SYSTEM 8150-240-421	970,257.41	$ 654,923.75	0%	$ -	
TURBINE-GENERATOR BUILDING,BEARING COOLING WATER SYSTEM 8150-240-441	1,152,348.24	$ 777,835.06	0%	$ -	
TURBINE-GENERATOR BUILDING,BUILDING FRAME 8150-240-020	5,643,620.08	$ 3,809,443.55	100%	$ 3,809,443.55	
TURBINE-GENERATOR BUILDING,CARD KEY ACCESS SYSTEM 8150-240-911	291,667.90	$ 196,875.83	100%	$ 196,875.83	
TURBINE-GENERATOR BUILDING,CHEMICAL AND VOLUME CONTROL SYSTEM 8150-240-224	25,346.10	$ 17,108.62	0%	$ -	
TURBINE-GENERATOR BUILDING,CHEMICAL INJECTION SYSTEM 8150-240-210	879,906.32	$ 593,936.77	0%	$ -	
TURBINE-GENERATOR BUILDING,CHEMICAL INJECTION SYSTEM 8150-240-438	35,789.37	$ 24,157.82	0%	$ -	
TURBINE-GENERATOR BUILDING,CIRCULATING WATER SYSTEM 8150-240-435	3,508,016.71	$ 2,367,911.28	0%	$ -	
TURBINE-GENERATOR BUILDING,COMMUNICATIONS EQUIPMENT 8150-240-010	847,080.07	$ 571,779.05	100%	$ 571,779.05	
TURBINE-GENERATOR BUILDING,COMPONENT COOLING WATER SYSTEM 8150-240-216	190,836.56	$ 128,814.68	0%	$ -	
TURBINE-GENERATOR BUILDING,CONDENSATE DEMINERALIZER SYSTEM 8150-240-434	161,936.93	$ 109,307.43	0%	$ -	
TURBINE-GENERATOR BUILDING,CONDENSATE SYSTEM 8150-240-430	21,366,478.04	$ 14,422,372.68	0%	$ -	
TURBINE-GENERATOR BUILDING,CRANES & HOISTS 8150-240-805	995,512.63	$ 671,971.03	100%	$ 671,971.03	The Turbine Building was used later on for a laydown and quality assurance inspection area for spent fuel baskets during the ISFSI project.
TURBINE-GENERATOR BUILDING,DC ELECTRICAL SYSTEM 8150-240-620	66,135.14	$ 44,641.22	100%	$ 44,641.22	
TURBINE-GENERATOR BUILDING,DECHLORINATION SYSTEM 8150-240-448	4,701.55	$ 3,173.55	100%	$ 3,173.55	
TURBINE-GENERATOR BUILDING,DEMINERALIZER SYSTEM 8150-240-243	877,527.95	$ 592,331.37	100%	$ 592,331.37	
TURBINE-GENERATOR BUILDING,DIESEL FUEL OIL SYSTEM 8150-240-626	859,986.67	$ 580,491.00	0%	$ -	
TURBINE-GENERATOR BUILDING,DOMESTIC WATER SYSTEM 8150-240-451	589,257.76	$ 397,748.99	100%	$ 397,748.99	
TURBINE-GENERATOR BUILDING,ELEVATORS 8150-240-144	67,605.12	$ 45,633.46	100%	$ 45,633.46	
TURBINE-GENERATOR BUILDING,EXCAVATION 8150-240-006	88,599.25	$ 59,804.49	100%	$ 59,804.49	
TURBINE-GENERATOR BUILDING,EXTERIOR WALLS 8150-240-040	1,797,798.30	$ 1,213,513.85	100%	$ 1,213,513.85	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
TURBINE-GENERATOR BUILDING,EXTRACTION STEAM SYSTEM 8150-240-423	8,313,195.08	$ 5,611,406.68	0%	$ -	
TURBINE-GENERATOR BUILDING,FEEDWATER SYSTEM 8150-240-429	34,097.93	$ 23,016.10	0%	$ -	
TURBINE-GENERATOR BUILDING,FEEDWATER SYSTEM 8150-240-431	25,347,008.01	$ 17,109,230.41	0%	$ -	
TURBINE-GENERATOR BUILDING,FIRE PROTECTION EQUIPMENT 8150-240-130	3,937,140.41	$ 2,657,569.78	100%	$ 2,657,569.78	
TURBINE-GENERATOR BUILDING,FLOORS AND FLOOR COVERINGS 8150-240-030	146,958.13	$ 99,196.74	100%	$ 99,196.74	
TURBINE-GENERATOR BUILDING,FOUNDATIONS 8150-240-011	98,274.06	$ 66,334.99	100%	$ 66,334.99	
TURBINE-GENERATOR BUILDING,GENERATOR EXCITER SYSTEM 8150-240-605	6,850.05	$ 4,623.78	0%	$ -	
TURBINE-GENERATOR BUILDING,HEAT VENTILATING AND AIR CONDITIONING 8150-240-120	2,097,826.19	$ 1,416,032.68	100%	$ 1,416,032.68	
TURBINE-GENERATOR BUILDING,HEATER AND MISCELLANEOUS DRAIN SYSTEM 8150-240-425	14,129,783.94	$ 9,537,604.16	100%	$ 9,537,604.16	
TURBINE-GENERATOR BUILDING,HYDROGEN COOLING SYSTEM 8150-240-418	373,641.94	$ 252,208.31	0%	$ -	
TURBINE-GENERATOR BUILDING,HYDROGEN SYSTEM 8150-240-419	1,100,409.33	$ 742,776.30	0%	$ -	
TURBINE-GENERATOR BUILDING,IN-PLANT COMMUNICATION EQUIP 8150-240-125	1,023.67	$ 690.98	100%	$ 690.98	
TURBINE-GENERATOR BUILDING,INSTRUMENT & SERVICE AIR SYSTEM 8150-240-810	2,540,298.47	$ 1,714,701.47	100%	$ 1,714,701.47	The air compressors were located in the Turbine Building.
TURBINE-GENERATOR BUILDING,INSTRUMENTS RACKS & PANELS 8150-240-460	4,161,860.95	$ 2,809,256.14	10%	$ 280,925.61	
TURBINE-GENERATOR BUILDING,INSTRUMENTS RACKS AND PANELS 8150-240-256	317,429.05	$ 214,264.61	10%	$ 21,426.46	
TURBINE-GENERATOR BUILDING,INTERIOR WALLS AND CEILINGS 8150-240-050	443,253.25	$ 299,195.94	100%	$ 299,195.94	
TURBINE-GENERATOR BUILDING,ISOLATED PHASE BUS 8150-240-200	111,236.50	$ 75,084.64	0%	$ -	
TURBINE-GENERATOR BUILDING,LADDERS AND STAIRWAYS 8150-240-013	243,697.15	$ 164,495.58	100%	$ 164,495.58	
TURBINE-GENERATOR BUILDING,LIGHTING AND CONTROLS 8150-240-070	13,722.45	$ 9,262.65	100%	$ 9,262.65	
TURBINE-GENERATOR BUILDING,LIGHTING AND CONTROLS 8150-240-110	869,489.73	$ 586,905.57	100%	$ 586,905.57	
TURBINE-GENERATOR BUILDING,LUBE OIL STORAGE AND FILTER SYSTEM 8150-240-416	1,636,331.61	$ 1,104,523.84	0%	$ -	
TURBINE-GENERATOR BUILDING,MAIN CONTROL & ELECTRIC BOARD 8150-240-640	73.36	$ 49.52	0%	$ -	
TURBINE-GENERATOR BUILDING,MAIN STEAM SYSTEM 8150-240-420	5,965,489.47	$ 4,026,705.39	0%	$ -	
TURBINE-GENERATOR BUILDING,MAKE-UP WATER TREATMENT SYSTEM 8150-240-446	862,695.20	$ 582,319.26	0%	$ -	
TURBINE-GENERATOR BUILDING,MISC GAS SUPPLY SYSTEM 8150-240-815	1,523,475.19	$ 1,028,345.75	0%	$ -	
TURBINE-GENERATOR BUILDING,PRIMARY MAKE-UP WATER SYSTEM 8150-240-245	173,306.11	$ 116,981.62	0%	$ -	
TURBINE-GENERATOR BUILDING,PROCESS RADIATION MONITOR SYSTEM 8150-240-262	1,682,860.02	$ 1,135,930.51	0%	$ -	
TURBINE-GENERATOR BUILDING,PROCESS SAMPLING SYSTEM 8150-240-267	1,046,878.84	$ 706,643.22	0%	$ -	
TURBINE-GENERATOR BUILDING,PROCESS STEAM SYSTEM 8150-240-422	484,719.85	$ 327,185.90	0%	$ -	
TURBINE-GENERATOR BUILDING,REACTOR COOLANT SYSTEM 8150-240-221	91,920.69	$ 62,046.47	0%	$ -	
TURBINE-GENERATOR BUILDING,REHEAT AND MOISTURE SEPARATOR SYSTEM 8150-240-428	723,199.33	$ 488,159.55	0%	$ -	
TURBINE-GENERATOR BUILDING,REHEAT AND MOISTURE SEPARATOR SYSTEM 8150-240-440	4,003,721.19	$ 2,702,511.80	0%	$ -	
TURBINE-GENERATOR BUILDING,ROOFS GUTTERS DOWNSPOUTS 8150-240-060	416,700.36	$ 281,272.74	100%	$ 281,272.74	
TURBINE-GENERATOR BUILDING,SECURITY EQUIPMENT 8150-240-123	542.33	$ 366.07	100%	$ 366.07	
TURBINE-GENERATOR BUILDING,STEAM GENERATOR BLOWDOWN SYSTEM 8150-240-254	14,120.46	$ 9,531.31	0%	$ -	
TURBINE-GENERATOR BUILDING,STEAM SEAL AND DRAIN SYSTEM 8150-240-426	256,694.33	$ 173,268.67	0%	$ -	
TURBINE-GENERATOR BUILDING,STORES EQUIPMENT 8150-240-138	390.98	$ 263.91	0%	$ -	
TURBINE-GENERATOR BUILDING,STRUCTURAL MATERIAL 8150-240-008	594,725.47	$ 401,439.69	100%	$ 401,439.69	
TURBINE-GENERATOR BUILDING,TG CONTROL AND SUPPORT EQUIPMENT 8150-240-410	24,012.40	$ 16,208.37	0%	$ -	
TURBINE-GENERATOR BUILDING,TG ELECTRO-HYDRAULIC CONTROL SYSTEM 8150-240-411	1,645,453.01	$ 1,110,680.78	0%	$ -	
TURBINE-GENERATOR BUILDING,TOOLS & EQUIPMENT 8150-240-136	21,559.38	$ 14,552.58	15%	$ 2,182.89	
TURBINE-GENERATOR BUILDING,TURBINE GENERATOR STATOR 8150-240-417	5,379,618.23	$ 3,631,242.31	0%	$ -	
TURBINE-GENERATOR BUILDING,TURBINE GENERATOR SYSTEM 8150-240-409	39,661,707.24	$ 26,771,652.39	0%	$ -	
TURBINE-GENERATOR BUILDING,TURBINE GENERATOR TURNING GEAR 8150-240-413	484,297.89	$ 326,901.08	0%	$ -	
TURBINE-GENERATOR BUILDING,TURBINE-GENERATOR CONTROL PANEL 8150-240-407	1,009.61	$ 681.49	0%	$ -	
TURBINE-GENERATOR BUILDING,UNDISTRIBUTED PROPERTY CHARGE 8150-240-001	161,885.71	$ 109,272.85	0%	$ -	
TURBINE-GENERATOR BUILDING,WATER PIPING SYSTEM 8150-240-090	1,475,462.73	$ 995,937.34	0%	$ -	
UNDISTRIBUTED PROPERTY CHARGE,UNDISTRIBUTED PROPERTY CHARGE 8150-010-001	52.52	$ 35.45	0%	$ -	
UNDISTRIBUTED PROPERTY,FURNITURE WITH NO LOCATION 8150-015-100	761.84	$ 514.24	0%	$ -	
UNWORKED ACCOUNT 8150-001-001	3,249,519.37	$ 2,193,425.57	0%	$ -	

Asset Location	100% Cost Investment	PGE Share	Plant In Service Share	Net	Notes
VEHICLES,VEHICLES, NO COMPANY NUMBER 8150-290-999	21,474.31 $	14,495.16	100% $	14,495.16	Maintenance used vehicles for transporting parts and tools to the worksite. Forklifts and mobile cranes were used for loading radwaste boxes and moving decommissioning and ISFSI equipment. Security used vehicles for patrols.
VEHICLES,VEHICLES, NUMBERS 006001 THRU 006999 8150-290-006	299,265.01 $	202,003.88	100% $	202,003.88	
VISITORS INFORMATION CENTER,BUILDING FRAME 8150-100-020	206,433.22 $	139,342.42	100% $	139,342.42	Visitors Information Center structure was needed because it housed asbestos-containing material.
VISITORS INFORMATION CENTER,COMMUNICATION EQUIPMENT 8150-100-010	136,906.89 $	92,412.15	0% $	-	
VISITORS INFORMATION CENTER,EMERGENCY OPERATING FACILITY 8150-100-131	664,159.32 $	448,307.54	0% $	-	
VISITORS INFORMATION CENTER,EXTERIOR WALLS 8150-100-040	213,043.85 $	143,804.60	100% $	143,804.60	
VISITORS INFORMATION CENTER,FENCING 8150-100-175	1,335.00 $	901.13	0% $	-	
VISITORS INFORMATION CENTER,FIRE PROTECTION SYSTEM 8150-100-130	11,565.89 $	7,806.98	100% $	7,806.98	
VISITORS INFORMATION CENTER,FLOORS & FLOOR COVERINGS 8150-100-030	101,891.39 $	68,776.69	0% $	-	
VISITORS INFORMATION CENTER,FOUNDATION & BASE SLAB 8150-100-012	107,606.10 $	72,634.12	100% $	72,634.12	
VISITORS INFORMATION CENTER,FURNITURE AND OFFICE EQUIPMENT 8150-100-100	108,792.21 $	73,434.74	0% $	-	
VISITORS INFORMATION CENTER,HEATING VENTILATING AND AIR CONDITIONING 8150-100-120	205,649.94 $	138,813.71	0% $	-	
VISITORS INFORMATION CENTER,IN-PLANT COMMUNICATIONS EQUIPMENT 8150-100-125	473.62 $	319.69	0% $	-	
VISITORS INFORMATION CENTER,LAB EQUIPMENT 8150-100-134	15,974.99 $	10,783.12	0% $	-	
VISITORS INFORMATION CENTER,MISC EQUIPMENT 8150-100-612	16,128.05 $	10,886.43	0% $	-	
VISITORS INFORMATION CENTER,MISCELLANEOUS EQUIPMENT 8150-100-199	3,788.54 $	2,557.26	0% $	-	
VISITORS INFORMATION CENTER,OUTSIDE FACILITIES 8150-100-006	445,798.45 $	300,913.95	0% $	-	
VISITORS INFORMATION CENTER,PARTITIONS & CEILINGS 8150-100-005	46,983.77 $	31,714.04	0% $	-	
VISITORS INFORMATION CENTER,PARTITIONS AND CEILINGS 8150-100-050	231,320.34 $	156,141.23	0% $	-	
VISITORS INFORMATION CENTER,PLUMBING 8150-100-090	7,308.87 $	4,933.49	0% $	-	
VISITORS INFORMATION CENTER,PRELIMINARY COSTS 8150-100-004	228,625.53 $	154,322.23	0% $	-	
VISITORS INFORMATION CENTER,ROOFS GUTTERS AND DOWNSPOUTS 8150-100-060	87,930.81 $	59,353.30	100% $	59,353.30	
VISITORS INFORMATION CENTER,SECURITY EQUIPMENT 8150-100-123	7,735.46 $	5,221.44	0% $	-	
VISITORS INFORMATION CENTER,SOUND SYSTEMS 8150-100-102	13,113.18 $	8,851.40	0% $	-	
VISITORS INFORMATION CENTER,STAIRWAYS 8150-100-070	19,852.42 $	13,400.38	100% $	13,400.38	
VISITORS INFORMATION CENTER,YARD LOOP DISTRIBUTION SYSTEM 8150-100-490	493.31 $	332.98	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),BUILDING FRAME 8150-440-020	220,085.10 $	148,557.44	100% $	148,557.44	Maintenance building and shop.
WAREHOUSE AND SHOP (MATERIAL SERVICES),CABINETS SHELVES AND COUNTERS 8150-440-140	51,687.26 $	34,888.90	100% $	34,888.90	
WAREHOUSE AND SHOP (MATERIAL SERVICES),CARD KEY ACCESS SYSTEM 8150-440-911	68,903.80 $	46,510.07	100% $	46,510.07	
WAREHOUSE AND SHOP (MATERIAL SERVICES),COMMUNICATIONS EQUIPMENT 8150-440-010	328,393.51 $	221,665.62	100% $	221,665.62	
WAREHOUSE AND SHOP (MATERIAL SERVICES),COMPUTER EQUIPMENT 8150-440-645	1,834,575.74 $	1,238,338.62	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),COMPUTER EQUIPMENT-NOT NUMBERED 8150-440-647	381,900.44 $	257,782.80	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),CONSTRUCTION BUILDINGS 8150-440-178	282,794.14 $	190,886.04	100% $	190,886.04	
WAREHOUSE AND SHOP (MATERIAL SERVICES),CRANES & HOISTS 8150-440-805	72,571.15 $	48,985.53	100% $	48,985.53	
WAREHOUSE AND SHOP (MATERIAL SERVICES),EXCAVATION 8150-440-006	4,839.34 $	3,266.55	100% $	3,266.55	
WAREHOUSE AND SHOP (MATERIAL SERVICES),EXTERIOR WALLS 8150-440-040	279,318.05 $	188,539.68	100% $	188,539.68	
WAREHOUSE AND SHOP (MATERIAL SERVICES),FENCING 8150-440-175	96,046.74 $	64,831.55	100% $	64,831.55	
WAREHOUSE AND SHOP (MATERIAL SERVICES),FIRE PROTECTION EQUIPMENT 8150-440-130	169,415.24 $	114,355.29	100% $	114,355.29	
WAREHOUSE AND SHOP (MATERIAL SERVICES),FLOORS AND FLOOR COVERINGS 8150-440-030	107,820.12 $	72,778.58	100% $	72,778.58	
WAREHOUSE AND SHOP (MATERIAL SERVICES),FURNITURE & OFFICE EQUIPMENT 8150-440-100	362,175.68 $	244,468.58	20% $	48,893.72	
WAREHOUSE AND SHOP (MATERIAL SERVICES),HEAT VENTILATING AND AIR CONDITIONING 8150-440-120	287,312.39 $	193,935.86	100% $	193,935.86	
WAREHOUSE AND SHOP (MATERIAL SERVICES),HOLDING FOR COMPUTER EQUIPMENT NUMBERS 8150-440-646	35,110.53 $	23,699.61	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),INTERIOR WALLS AND CEILINGS 8150-440-050	50,934.97 $	34,381.10	100% $	34,381.10	
WAREHOUSE AND SHOP (MATERIAL SERVICES),LAB EQUIPMENT 8150-440-134	5,658.35 $	3,819.39	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),LIGHTING 8150-440-110	265,302.35 $	179,079.09	100% $	179,079.09	
WAREHOUSE AND SHOP (MATERIAL SERVICES),MISC SPECIAL TOOLS 8150-440-910	22,648.39 $	15,287.66	100% $	15,287.66	
WAREHOUSE AND SHOP (MATERIAL SERVICES),MISCELLANEOUS BUILDING EQUIPMENT 8150-440-199	115,542.90 $	77,991.46	100% $	77,991.46	
WAREHOUSE AND SHOP (MATERIAL SERVICES),MODELS DISPLAYS & FILMS 8150-440-600	12,507.97 $	8,442.88	0% $	-	
WAREHOUSE AND SHOP (MATERIAL SERVICES),PLUMBING 8150-440-090	62,844.35 $	42,419.94	100% $	42,419.94	

Asset Location	100% Cost Investment		PGE Share	Plant In Service Share		Net	Notes
WAREHOUSE AND SHOP (MATERIAL SERVICES),ROOFS GUTTERS DOWNSPOUTS 8150-440-060	48,801.68	$	32,941.13	100%	$	32,941.13	
WAREHOUSE AND SHOP (MATERIAL SERVICES),SECURITY EQUIPMENT 8150-440-123	207.64	$	140.16	100%	$	140.16	
WAREHOUSE AND SHOP (MATERIAL SERVICES),SPARE PARTS 8150-440-915	79,923.48	$	53,948.35	100%	$	53,948.35	
WAREHOUSE AND SHOP (MATERIAL SERVICES),STORES EQUIPMENT 8150-440-138	509,023.30	$	343,590.73	100%	$	343,590.73	
WAREHOUSE AND SHOP (MATERIAL SERVICES),STRUCTURAL MATERIAL 8150-440-008	58,096.31	$	39,215.01	100%	$	39,215.01	
WAREHOUSE AND SHOP (MATERIAL SERVICES),TOOLS & EQUIPMENT 8150-440-136	832,925.28	$	562,224.56	100%	$	562,224.56	
					$	-	
	670,820,435.56		452,803,794.00			214,488,944.77	

Gross Plant Cost Total	556,249,705
Accum Amort	(261,663,314)
Net Plant	294,586,391
Plant In Service Share of Gross	38.6%
Implied Share of Net Plant	113,592,014

UE-88 REMAND / PGE EXHIBIT / 6400
HAGER

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

February 15, 2005

I. Introduction

Q. Please state your name and position.

A. My name is Patrick G. Hager. My position is Manager, Regulatory Affairs. My current qualifications are at the end of this testimony.

Q. Have you previously provided testimony in this docket?

A. Yes. I have previously offered cost of capital testimony and sponsored three PGE Exhibits. First, I co-sponsored PGE's opening cost of capital testimony in UE 88 (PGE Exhibit 700). Second, I sponsored PGE's testimony that summarized and supported the cost of capital stipulation PGE reached with the OPUC Staff (PGE Exhibit 2600). Third, I provided testimony regarding the expected financial effects on PGE under different Trojan return alternatives (PGE Exhibit 2300).

Q. What is the purpose of your testimony?

A. The purpose of my current testimony is three-fold. First, I summarize PGE's cost of capital testimony in UE 88. PGE prepared and submitted cost of capital testimony in 1993 and 1994, estimating PGE's cost of capital for the 1995-1996 test period. Second, I provide a qualitative analysis of the cost of capital effects of the Oregon Court of Appeals interpretation precluding the Commission from permitting a return on plant that has been retired economically to achieve least cost for customers. I show that, had this interpretation of Oregon law been available at the time of UE 88, PGE would have supported a higher required return on equity as well as on debt to reflect the increased risk of Oregon's regulatory environment. Given the significant new information that the Commission cannot set rates based on allowing PGE a return on our undepreciated Trojan investment, I have modified my estimated range for PGE's Required Return on Equity (RROE). My range differs depending on whether the regulatory environment is one of simply "no return on but rapid recovery of" or "no return on and slow recovery of" such investments. If the Commission allows PGE to collect its unamortized investment in Trojan over a short period of time, then my estimated range for PGE's RROE is 11.7% to 11.94%, with a point estimate of 11.85%. If the Commission specifies a longer period of time over which PGE can collect its investment, then my estimated range is 12.8% to 13.4%, with a point estimate of 13.1%. Third, I provide a brief overview of the remaining cost of capital witnesses. Their testimony supports my analysis and my estimate of the range for the higher required return.

II. PGE's UE 88 Cost of Capital Analysis

A. Overview

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. 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. Expected ROE refers to an investor's anticipated return on an investment security as part of a decision to purchase or sell the security. 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 for the potential return on equity that the company can earn. If the authorized return on equity is set "low," then investors will expect the company to earn a lower return on equity. Conversely, if the authorized return on equity is set "high," then investors will expect the company to earn a higher return on equity.

Q. What do you mean by PGE's Required Return on Equity (RROE)?

A. PGE's RROE is the ROE that investors require in order to buy or hold PGE's common equity. This is the appropriate rate for PGE, considering the pricing and operation risks proposed for PGE as discussed elsewhere in the UE 88 filing.

Q. Why is it important that PGE's authorized ROE be set at or above PGE's RROE?

A. It enables PGE to attract equity capital on favorable terms in the marketplace.

Q. Please explain.

A. 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 and expected returns on other (alternative) investments. Most sophisticated 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. 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. One consequence of this is that PGE would have to issue more shares than otherwise to raise the same amount of capital, increasing its dividend cost and hurting its financials.

To ensure its ability to attract common equity on favorable terms in the marketplace, PGE must provide current and prospective shareholders with an ROE that encompasses their range of required ROEs. The return I recommend accomplishes this goal and would have allowed PGE to attract capital on favorable terms in the marketplace, had the Commission adopted it in UE 88.

1. <u>The Discounted Cash Flow and Capital Asset Pricing Models</u>

Q. You stated that investors used one or more financial models to determine the required return on their investment. What financial models did you use in 1993 and 1994 to determine PGE's RROE?

A. I used the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM) models to calculate the range for PGE's RROE. I also considered authorized ROEs that had been recently granted in other state jurisdictions.

Q. Please briefly describe the CAPM model.

A. The Capital Asset Pricing Model (CAPM) focuses on the investor's portfolio and the risk associated with a particular portfolio. Specifically, CAPM assumes that the investor holds a market portfolio consisting of every financial asset in the world. It is from the investor's portfolio decisions that the risk and value of an individual firm can be determined and, thus, the Required Return on Equity (RROE) for the firm can also be found. The firm's relevant risk can be measured by a single number, Beta. The Required Rate of Return is then a simple function of Beta:

RROE = (Risk-free rate) + Beta times (Expected return on the market portfolio - Risk free rate) **(2)**

Q. What is Beta?

A. By definition, Beta is the regression coefficient of the company's common stock return or the covariance of the company's stock return with the market return divided by the variance of the market return. More intuitively, Beta can be thought of simply as the ratio of changes in the company's return to changes in the market's return.

Q. What is the Expected Return minus the Risk-free rate?

A. This term is called the Market Risk Premium. It is the return above the risk-free rate that an investor must receive in order to hold the market portfolio instead of the risk-free security.

Q. Is the CAPM a Risk Premium model?

A. Yes. Like other Risk Premium Models, CAPM attempts to estimate the premium over and above the risk-free rate that an investor requires in order to hold an investment instead of the risk-free security. Dr. Hess also describes the CAPM model in PGE Exhibit 6700.

Q. Please briefly describe the DCF model.

A. 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. The most common forms of the DCF model are single- and multi-stage.

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:

$$P_o = D_1 \div (k_e - g) \qquad \textbf{(3)}$$

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:

$$k_e = (D_1 \div P_0) + g \qquad \textbf{(4)}$$

This general form of the DCF model is known as a single-stage growth model because it assumes a constant dividend growth rate over time.

Q. What is the multi-stage DCF model?

A. The multi-stage DCF does not assume a constant dividend growth rate so that solving for the cost of equity is more complicated. Equations 3 and 4 above assume a single growth rate. If more than one dividend growth rate is assumed, then the equations become more complex:

$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_n}{(1+k)^n} + \frac{P_n}{(1+k)^n} \qquad \textbf{(5)}$$

or

$$P_o = \sum_{t=1}^{n} \frac{D_t}{(1+k)^t} + \frac{P_n}{(1+k)^n} \qquad \textbf{(6)}$$

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 (6) above. Dr. Blaydon describes the DCF model in more detail in PGE Exhibit 6600.

2. *Opening cost of capital testimony*

Q. Please summarize PGE's opening cost of capital testimony in UE 88.

A. PGE filed its opening cost of capital testimony on November 8, 1993 (PGE Exhibit 700). We included financial information available through June 30, 1993 and stated that we planned to update our estimate with more current information in our rebuttal testimony. Our initial estimate for PGE's cost of capital for the test period 1995-1996 was:

Table 1

Opening Testimony RROE Estimates

Estimation Method	Range
Discounted Cash Flow	10.96% - 11.91%
CAPM	11.02% - 12.10%

3. Settlement (Rebuttal) cost of capital testimony.

Q. Did PGE file additional cost of capital testimony?

A. Yes. PGE reached a settlement with OPUC Staff concerning our 1995-1996 test period cost of capital. PGE filed testimony supporting the settlement in mid-November 1994, almost a year after our opening testimony.

Q. Please summarize this second round of testimony.

A. In our rebuttal testimony, we updated our estimate for PGE's cost of capital using financial information available through mid-November 1994. Our updated estimated range was:

Table 2

Updated RROE Estimates

Estimation Method	Range
Discounted Cash Flow	11.46% - 12.10%
CAPM	12.65% - 13.37%

The stipulated RROE was included in our updated estimated range for PGE's cost of capital.

Q. Why did your estimated RROE range increase from that in your opening testimony?

A. My direct testimony on PGE's cost of capital, filed in November 1993, was prepared using information available to investors as of June 30, 1993. The financial markets changed significantly between June 1993 and November 1994, not only with higher interest rates and stock market levels, but also demonstrating volatility during the period.

Q. How did the bond market behave during the June 1993 to November 1994 period?

A. The change and the associated volatility in the bond market can be illustrated using the "Treasury benchmark" 30-year bond, shown in PGE Exhibit 2603. Between June and mid-October 1993, the period just prior to our initial filing, interest rates, as measured by the 30-year Treasury Bond, declined by over 90 basis points, from 6.70% to 5.78%. However, interest rates then began to rise, reaching 7.55% in mid-August 1994, when Staff prepared its response testimony and rose further to 8.10% in early November 1994, at about the time of the cost of capital stipulation. As of November 21, 1994, the 30-year Treasury bond was at 8.13%, significantly higher than when we or Staff prepared our estimates.

Q. Describe how the stock market was higher and more volatile over this same time period?

A. The S&P 500 is frequently used as an index for the overall stock market. Figure 1 in PGE Exhibit 2604 shows the monthly average closing price for the Standard & Poor's 500 Index (S&P 500) from January 1993 through mid-November 1994. Figure 2 shows the daily high, low, and close for the period July 1, 1993 through November 10, 1994. Both graphs show that the S&P 500 rose from July 1993 through January 1994. Figure 2 shows that the daily volatility was significant at times. In mid-March 1994, the S&P 500 began a short but substantial decline, from approximately 470 to 441 in May, a 6% decline in less than two months. The S&P 500 fell below its July 1, 1993 level. Between May and November 1994, the S&P 500 climbed above 465, but its rise was punctuated with short and large declines. Given the changes in the financial market between May 1993 and November 1994 and the volatility, the higher and wider range for RROE is not unexpected.

Q. What effect did the higher interest rates, higher stock market, and the volatility have on PGE's required ROE?

A. The higher interest rates and stock market and volatility increased PGE's required ROE. My updated RROE estimates in Table 2 reflect this.

Q. Please describe the cost of capital settlement in UE 88.

A. PGE and the OPUC Staff reached a settlement in early November 1994 regarding PGE's authorized cost of capital, including its capital structure. Tables 3 and 4 below detail the settlement.

Table 3

Test Year 1995

	Capital Structure	Cost	Weighted Cost
a. Long-Term Debt	49.14%	7.71%	3.79%
b. Preferred Stock	5.42%	8.27%	0.45%
c. Common Equity	45.44%	11.60%	5.27%
	100.00%		
Rate of Return			9.51%

Table 4

Test Year 1996

	Capital Structure	Costs	Weighted Cost
a. Long-Term Debt	48.86%	7.82%	3.82%
b. Preferred Stock	4.67%	8.27%	0.39%
c. Common Equity	46.47%	11.60%	5.39%
	100.00%		
Rate of Return			9.60%

Q. Was the settlement within your updated estimated range for PGE's required ROE?

A. Yes. My updated estimated range for PGE's required ROE was 11.46% to 13.37%. The 11.60% settlement for PGE's authorized ROE was towards the bottom of the range, but acceptable to PGE as we expected full recovery of and on our investment in Trojan.

Q. Did the Commission accept the cost of capital settlement?

A. Yes. OPUC Order No. 95-322 adopted the cost of capital stipulation (OPUC Order No. 95-322, page 24 and Appendix E).

4. *Effect of Trojan recovery alternatives on PGE's financial ratios*

Q. Please briefly describe this testimony.

A. In November 1994, I provided testimony regarding four proposed Trojan recovery alternatives and their effects both upon PGE's ability to attract capital in the marketplace and PGE's cost of capital (PGE Exhibit 2300).

Q. Which four proposed Trojan recovery alternatives did you analyze?

A. I analyzed the three alternatives proposed by the OPUC Staff and CUB that would have had the largest financial impacts upon PGE. I compared these alternatives or scenarios to PGE's proposal, which was full recovery of and on the remaining Trojan investment. The four scenarios were:

1. PGE Proposal (100% recovery, full return, full amortization);
2. OPUC Staff Alternative 4 (0% recovery, no return, no amortization);
3. OPUC Staff Alternative 3 (100% recovery, no return, full amortization of remaining investment); and
4. CUB Alternative 1 (29% Recovery, no return, full amortization of remaining investment).

Q. What did your analysis show regarding these four alternatives?

A. My analysis showed that under any of the three proposed disallowance scenarios, PGE's financials would deteriorate significantly. Its access to and its cost of capital would be harmed. PGE investors would be harmed because, at a minimum, PGE's bond prices would decrease, and PGC's common stock price would decline as well[1]. PGE investors would be further harmed since PGE's operating income under the disallowance scenarios would be

[1] At that time, PGE's stock did not trade. It was held by Portland General Corporation (PGC), whose stock traded on the NYSE.

significantly less than if full recovery of and on the investment were allowed, thereby reducing the expected return.

Q. Are your analyses still relevant to determining PGE's cost of capital as of November 1994?

A. Yes. However, in my analyses, I, as well as financial investors, assumed that PGE could receive a return of and on its unamortized investment in Trojan. In other words, Oregon law did not prohibit the Commission from allowing PGE a return on the Trojan investment the Commission allowed for recovery. The intervening interpretation by the state Court of Appeals requires that I modify my analyses to reflect Oregon regulation in which investors could expect a return of any economically-retired investment but no return on such investments. I update my analyses in Section III A below to reflect the change in investors' expectations.

B. Estimating PGE's Cost of Capital

Q. Mr. Hager, please describe how, in 1993 and 1994, you estimated PGE's Required Return on Equity.

A. I considered the following:

1. The returns and the underlying risk factors that are important to investors when they estimate the required return from a potential investment;
2. The financial and economic markets;
3. PGE's financing needs of approximately $500 million; and
4. My RROE calculations using two generally used models, the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow model (DCF).

I estimated a reasonable range for the CAPM and the DCF and determined the point estimate for PGE's RROE by considering the two estimated ranges, PGE's financing needs, the financial and economic markets, and investors' expected risks and returns.

1. <u>The underlying factors</u>

Q. What kinds of returns can a stockholder expect?

A. Common stock provides two kinds of return: capital gains and dividends. Capital gain (or loss) is the return the stockholder receives due to the change in the stock price. The capital effect can be either positive or negative. Dividends are payments made quarterly to stockholders. Together, the return an investor receives from capital gains and from dividends is his total return.

Q. What factors influence the investor's expected return on common equity?

A. As I noted in Section II above, the required return on any security investment can be conceptualized as:

$$k = r + \pi + i + b + f + l \qquad \textbf{(1)}$$

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

We can consider these terms a couple of different ways. First, as I defined them above, the first two terms of equation (1) equal the nominal interest rate. The remaining four terms are the "risk premium" <u>above</u> the nominal interest rate that the investor requires to purchase the common stock or investment. A second way to conceptualize equation (1) is to again equate the first two terms to the nominal interest rate, but to now consider the next three terms (i.e., interest rate, business and financial risk) as default premium risk and market premium risk. In this case, an alternative expression for equation (1) is:

$$k = n + dpr + mpr + l \qquad (1')$$

where k = required return
n = nominal interest rate
dpr = default premium risk
mpr = market premium risk
l = liquidity risk

Q. Are all possible factors that could influence investors' expectations regarding returns included in equations (1) and (1') above?

A. In theory, yes. For example, the Oregon Court of Appeals interpretation regarding no return on investment that has been economically retired could be considered business risk. Investors might not have expected this risk, but in theory the risk can be classified as business risk. Another example of business risk would be the recent rise in energy prices, including natural gas, wholesale power, and oil.

2. <u>The general process</u>

Q. How did you develop your estimates for PGE's cost of capital in UE 88?

A. We generally followed the same process and used the same models for both our initial and rebuttal testimony, as I described in our opening 1993 testimony (PGE Exhibit 700). We selected a sample of electric utilities based on specified criteria, estimated the RROE for each utility using the CAPM and DCF models, then constructed a range for the CAPM and DCF estimates based on the results.

3. <u>Specific assumptions in the estimation</u>

Q. What specific assumptions were embodied in your cost of capital estimates?

A. When we made our cost of capital estimates in 1993 and 1994, we assumed that all factors not included in our models would remain unchanged. For example, we implicitly assumed that PGE was an average electric utility facing average risk similar to a combination of electric utilities from the S&P and Moody's indices. To the extent that either PGE, the sample groups, or the economic, financial, and/or political environment changed significantly, the forecast would have to be modified as well.

Q. How might PGE "change significantly?"

A. One way that PGE would change significantly from the average utility would be if its business or regulatory climate changed significantly. For example, suppose all retail customers had been given the option on April 1, 1995 to go to direct access while PGE still had remained the supplier of last resort. This situation would have significantly increased PGE's business risk.

Another example, as described by Dr. Makholm in his testimony, is if the Commission was to decide that PGE had to amortize undepreciated but no longer economic plant over that plant's original depreciation life, without a return on the plant investment. This would also increase PGE's risk beyond that of an average electric utility.

A third example would be if PGE faced a significantly different economic, financial, and/or political environment from that of the sample group, such as a continuing drought or economic recession.

III. "No Return On" Effects

A. Effects on PGE's Capital Structure and Financial Ratios

Q. You stated that in November 1994 you calculated PGE's financial ratios and compared them to those used by financial rating agencies. Have you updated your analysis?

A. Yes. PGE Exhibit 6401 provides PGE's financial ratios using 1995 historical financial information and assuming four scenarios for return on PGE's investment in Trojan and compares these ratios to the appropriate Standard & Poor's (S&P) guidelines. Table 5 below reproduces these financial ratios.

Table 5

17-Year Amortization Scenarios

Financial Ratio		1995 Actual	No Return On	No Equity Return	Proper Plant-in-Service No Return On	Proper Plant-in-Service No Equity Return
FFO to Debt	↑	22.43	17.97	18.80	17.97	19.13
Interest Coverage	↑	4.16	3.53	3.65	3.53	3.69
Pretax Interest Coverage	↑	3.01	0.95	1.85	1.46	2.14
Total Debt to Capital	↓	56.18	58.98	57.72	58.26	57.33
Net Cash Flow to Cap Ex	↑	90.75	66.62	71.12	66.62	72.91

Note: Arrows indicate direction for movement to achieve improved bond rating.

Q. How do these financial ratios compare with those listed by S&P for an "A" rating on secured long-term bonds?

A. As the graphs in PGE Exhibit 6401 show, for PGE's financial ratios based on 1995 actuals, four of the five ratios are probably within the "A" or "A-" rating. The only ratio that is clearly outside of the "A" rating is the Total Debt to Capital ratio. At the time, PGE was constructing Coyote Springs I, which would help explain the large amount of short-term debt.

Q. You also calculated financial ratios under four alternative scenarios. Which four alternatives did you consider?

A. I calculated the financial ratios for both the 1-year and 17-year amortizations for PGE's investment in Trojan. My work papers contain both sets of calculations. However, for presentation purposes, I considered only the long-term (17-year) amortization scenarios. The alternatives that I considered are:

1. No return on PGE's Trojan investment. PGE does not receive a return on its investment and is required to collect its unamortized investment over 17 years.
2. No "equity" return on PGE's Trojan investment. PGE recovers its cost of debt on its investment and is required to collect its unamortized investment over 17 years.
3. No return on PGE's Trojan investment and proper plant in service. PGE's recommended plant classification is accepted, resulting in approximately $80 million higher plant in service on April 1, 1995. However, PGE does not receive a return on the balance of its Trojan investment and is required to collect the balance of its unamortized investment over 17 years.
4. No "equity" return on PGE's Trojan investment and proper plant in service. PGE's recommended plant in service is accepted, resulting in approximately $80 million of Trojan as plant in service as of April 1, 1995. However, PGE recovers its cost of debt on the balance of its Trojan investment and is required to collect the balance of its unamortized investment over 17 years.

Q. Are the financial ratios significantly different under the four alternatives

A. Yes. Under each of the scenarios, PGE's financial ratios decline significantly, most likely leading to a downgrade in PGE's bond rating.

Q. These financial ratios are based on 1995 PGE actuals. Do they show the full 12-month financial impact of the recovery scenarios?

A. No. PGE's retail rates for its UE 88 general rate case went into effect on April 1, 1995 but were superseded by UE-93 rates in late November 1995. Thus, we used only nine months instead of twelve in our evaluation, but the ratios we show are comparable to the ones used by the S & P guidelines.

Q. Why did you use 1995?

A. We wanted to reflect the impact of the scenarios on PGE's finances under retail rates associated with UE 88.

Q. Would the impact of the scenarios be the same in the following years as in the first year?

A. Yes and no. The financial impact would be somewhat less, but the effect on PGE's bond rating would most likely be the same. PGE would remain at the lower bond rating.

B. Effects on Required Rate of Return

Q. In the fall of 1994, did investors expect that PGE would receive a return on and of their investment in the Trojan Nuclear Plant?

A. Yes. All of the investment literature discussed PGE's financial outlook as "positive." No one mentioned, let alone discussed, the remote possibility that PGE could not receive a return on its Trojan investment as the result of judicial interpretation of ORS 757.355. A rational investor would have concluded that PGE would receive a return on Trojan.

Q. Would investors have required a different return on PGE's equity had they known that PGE would not receive a return on its Trojan investment?

A. Yes. Investors did not factor this new risk into their expectations.

Q. How would investors factor this risk into their expectations?

A. Investors would most likely consider this risk in several ways. The Trojan plant was a significant part of PGE's regulated rate base and, hence, a significant part of PGE's earning potential. Removing approximately 15% of PGE's rate base would decrease PGE's earning potential and increase the risk to investors in a number of areas, including extreme company financial hardship, late payments, lower reinvestment returns, economic loss due to illiquidity in PGE's and PGC's securities, capital loss in the value of their financial securities, etc.

Given these additional and/or increased risks, an investor would have required a higher return than the authorized 9.5% ROR and the 11.6% ROE. How much higher a return they would have required depends on several factors, including: how fast PGE could recover its investment (directly related to the amortization period for PGE's investment in Trojan); whether PGE would receive its cost of debt related to its Trojan investment; the liquidity of PGE securities (PGE preferred stock, commercial paper, and long-term debt as well as PGC common stock); and, the extent to which the Commission and/or PGE had taken steps to minimize the reoccurrence of this scenario.

Q. How would you estimate investors' expectations in November 1994, given the same conditions, except for the Oregon Court of Appeals interpretation that no return on PGE's Trojan investment was allowed?

A. I would use the same information available to investors in November 1994, calculate the expected ROE range using the DCF and CAPM models, and then calculate the appropriate point estimate using the quantitative and qualitative factors discussed above. I would also consider the information provided by the other cost of capital witnesses in this docket, including Drs. Makholm (PGE Exhibit 6500), Blaydon (PGE Exhibit 6600), and Hess (PGE Exhibit 6700).

Q. Have you performed such a calculation?

A. Yes. I determined two point estimates for PGE required ROR and ROE, depending on the amortization period over which PGE would be allowed to collect its investment in Trojan. If PGE could collect its investment over one year, PGE's required ROE would be 11.85%, slightly higher than that authorized for the 1995-1996 period, but still below the mid-point of my combined DCF/CAPM ranges and just above the mid-point of the DCF range.

If, however, the Commission in UE 88 had set a longer amortization period, such as 17 years, then PGE's required ROE would have been 13.10%, about 150 basis points higher than that authorized for the 1995-1996 period. Table 6 below shows PGE's estimated cost of capital and its components, if the Commission had been making a decision on RROE knowing that it could not set rates on a basis that included a return on undepreciated Trojan investment.

Table 6
Summary Results for PGE's Updated RROE

	Amortization Period	
	1-yr	17-yr
Required Return on Equity	11.85%	13.10%
Required Rate of Return	9.62%	10.19%

Q. Please explain how you derived your estimates for PGE's RROE, if no return is allowed on PGE's investment in Trojan.

A. First, as I discussed above, it's clear that investors would demand a higher rate of return on their investment because of the increased risk that they face with investing in a company subject to the Oregon regulatory scheme. Dr. Hess makes a similar analysis in his testimony, using the CAPM model to demonstrate this. In addition, Dr. Makholm discusses the regulatory compact and the impact that no return on economically-retired assets would have.

Second, in 1993 and 1994, when I estimated the appropriate ranges for PGE's RROE in my rebuttal testimony, I used electric utilities from the Moody's and Standard & Poor's indices that met my specified financial criteria (PGE Exhibit 700, Section VI-Appendix). The result was an expected range for an electric utility with average risks. It's clear that PGE is no longer an electric utility with average risk. Indeed, if investors cannot receive a return on the undepreciated balance in assets retired for economic reasons, then PGE will have significantly higher risk than the average electric utility. Thus, given the updated results for PGE's expected 1995 financial ratios and my conclusions in the prior paragraph, I would conclude that the appropriate point estimate for PGE under these circumstances would be towards the high end of the range rather than towards the median or mean.

Q. Why are your estimates different for short versus long amortization of investment retired for economic reasons?

A. The effect of the Oregon Court of Appeals interpretation assuming a short amortization period is that investors face greater reinvestment risk and some loss of economic value associated with any lag in PGE's recovery of the investment. The loss in economic value becomes much greater if the Commission adopted long amortization periods for economically-retired assets, notwithstanding the Oregon Court of Appeals interpretation.

Q. What is reinvestment risk?

A. Reinvestment risk is the economic or opportunity loss from having to reinvest in a lower yielding security. When investors buy a security such as a bond or common equity, they usually receive at least a partial return in the form of a coupon payment or dividend. The investor will then invest the coupon or dividend. The extent to which the returns from these new investments are different from those on the original bond or common stock is reinvestment risk.

An example, using a bond holder, is easiest to understand. Suppose you bought a $1,000 PGE 20-year (long-term) bond at par (i.e., $1,000) that had a coupon rate of 7%. Each year, you would receive $70. Now, suppose interest rates decline. In this case, you could still reinvest the $70, but the return on that $70 would be lower than 7%. This is reinvestment risk. Both short-term and long-term investors have this reinvestment risk.

Q. What additional reinvestment risk would PGE investors face, given a short amortization period under the Oregon Court of Appeals ruling?

A. The PGE investor could face an early return of his principal. That is, what is unusual or outside of investors' expectations here is the possible sudden return of the investor's principal, depending on PGE's capital needs after a plant retired for economic reasons. Otherwise, the investor would expect his principal to remain invested for a much longer time.

Q. Please explain.

A. Let me return to the $1,000 PGE bond example. When you bought this bond, you expected to have an investment that would yield 7% per year until the bond matured. Under the short-term recovery scenario, PGE receives all of its remaining unamortized investment in Trojan over one year, or approximately $340 million. PGE will redeploy this cash by borrowing less or redeeming debt. This bond holder now has the risk that PGE will redeem its bond immediately, instead of waiting until the bond's maturity debt. In this situation, the investor now faces the risk of a lower return, not just on the $70 coupon payment, but also on the full $1,000 investment. The investor would, thus, demand a higher return than otherwise to buy PGE's bond.

Q. Would this reinvestment risk also apply to common and preferred shareholders?

A. Yes. As an example, in addition to redeeming debt, PGE could also buy back some of its common and/or preferred stock. As with the bondholder, the shareholder would receive his principal back much sooner than expected and would have to reinvest his principal. The shareholder is likely to have suffered a capital loss since PGE's earning capacity would be diminished, reducing expected returns, resulting in a reduced price of PGE stock.

Q. How did you determine the required ROE for the long-term (or 17-year recover) investor?

A. As I noted above, the required ROE would be towards the high end of the range. I used the top quartile of my updated range as the appropriate range for the higher required ROE. This range is 12.9% to 13.4%. The midpoint of the range is 13.15% or approximately 150 basis points above the 11.6% in the cost of capital stipulation. I thus used 13.1% as my point estimate.

Q. Why did you use the bottom quartile of the range for the 1-year amortization scenario?

A. The stipulated ROE was 11.6%, which represented the RROE for an average electric utility. If PGE now faced the risk of a 1-year amortization of a significant portion of its rate base, then investors would face the risk of early redemption. They would require a premium over the RROE for an average electric utility. I used the upper part of the bottom quartile of the overall range as my range for the 1-year amortization scenario.

Q. Please explain how you calculated the range for the 1-year amortization scenario.

A. The bottom quartile of my range was 11.46% to 11.94%, with a median of 11.7%. I took the midpoint of the range between the median and the top end of the bottom quartile, yielding 11.82% or approximately 25 basis points above the 11.6% in the cost of capital stipulation. I thus used 11.85% as my point estimate.

Q. For how long would investors require a higher return on their investment?

A. Investors would require higher returns on their investment until the increased risk that they perceive has either been mitigated or removed.

Q. How might these risks be removed?

A. The best way to remove these risks is to amend or revise the Oregon Revised Statutes to allow for recovery of plant that has been economically displaced together with financing costs, if the Commission spreads such recovery over time.

Q. If the Commission adopted a higher required return for PGE for the 1995 through 2000 period, would the Commission be setting a precedent for PGE's future required ROE?

A. No. By taking this action, the Commission would demonstrate that it would take actions to mitigate risks outside of PGE's normal business. Absent the unique circumstance presented by the premature closing of Trojan and the determination that no return on the remaining plant balance can be provided, future investors would not require a higher return.

Q. Are financial rating agencies concerned about PGE's recovery of its Trojan investments?

A. Yes. PGE Exhibit 6402 is a copy of the January 26, 2005, S&P Research Report on PGE. S&P specifically notes as a major "weakness" the litigation risk of PGE's recovery of its investment in Trojan and discusses the litigation. S&P notes that the outcome of the Trojan case could have a major impact on PGE's bond rating.

IV. Qualifications

Q. Mr. Hager, please summarize your qualifications.

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. I am responsible for determining PGE's revenue requirements as well as estimating PGE's Required Return on Equity.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
6401	PGE's Historical Financial Ratios
6402	S&P Research Report on PGE, January 26, 2005

PORTLAND GENERAL ELECTRIC
FINANCIAL FORECAST

Financial Ratios	Calculated from 1995 10-K
FFO / Interest Coverage	
Net Income	81,036
Adjustments:	
Add: Depreciation	
Add: Amortization	143,619
Add: Deferred Income Tax	(9,555)
Add: Deferred ITC	(5,549)
Less: AFDC(Debt and Equity)	(11,065)
Less: Other non-cash credits to income (PCA and PRM activities)	49,567
Less: Equity Income	
Cash Flow From Operations	248,053
Incurred Interest	
Total Interest Charges	79,128
Less: Interest Charges on QUIDS	(6,188)
Less: AFDC - Debt	7,808
Total Interest Incurred	80,749
Cash Flow From Operations + Total Interest Incurred	328,802
FFO / Interest Coverage Ratio	**4.16**
Pre-tax Interest Coverage Ratio	
Net Income	81,036
Adjustments:	
Add: Gross Interest Expense	79,128
Add: Income Taxes	89,064
Less: AFDC Equity and Debt	(11,065)
Less: Equity Income	
Adjusted Earnings Before Interest & Taxes	238,163
Total Interest Incurred	79,128
Pre-tax Interest Coverage Ratio	**3.01**

Financial Ratios	Calculated from 1995 10-K
Total Debt / Total Capitalization	
LTD (excluding conservation bonds and current portion of LTD)	890,556
Less: 30% of QUIDS Balance	(23)
Add: Current Portion of long term debt (2) (excluding Conservation Bonds)	95,114
Add: Short Term Debt Balance	170,248
Total debt	1,155,896
Preferred Stock	40
Common Stock	191,301
Other Paid In Capital	574,468
Retained Earnings	135,885
Accumulated Other Comprehensive Income	
Total Shareholder's Equity	901,694
Add: LTD (excluding conservation bonds and current portion)	890,556
Add: Current LTD (excluding conservation bonds)	95,114
Add: Short term debt balance	170,248
Total Capitalization	2,057,612
Total Debt / Total Capitalization	**56.18%**
FFO / AverageTotal Debt	
Funds From Operations	248,053
Average Total long term debt	1,105,907
FFO / Total Debt	**22.43%**
Debt/Equity	
Common Equity	933,148
long term debt (2) (excludes LTD w/in 1 Year, includes 100% Quids)	890,556
Preferred Stock (excludes sinking fund)	40,000
Total Capitalization - OPUC	1,863,704
Common Equity Ratio - Per OPUC	**50.07%**
Add 30% of QUIDs	(23)
Cap calculation changes for Rating Agency	
Add Long-Term Debt due within one year	105,114
Add Preferred Sinking Fund	
Add Short-Term Debt	170,248
Total Capitalization - Rating Agency	2,139,066
Common Equity Ratio - Per Rating Agency	**43.62%**

Financial Ratios

	Calculated from 1995 10-K
Net Cash Flow / Capital Expenditures	
Funds From Operations	248,053
Less: Dividends Paid	(62,396)
Net Cash Flow	185,657
Cash Flows from Investing Activites	215,645
Less: AFDC(Debt and Equity)	(11,065)
Capital Expenditures	204,580
Net Cash Flow / Capital Expenditures	**90.75%**

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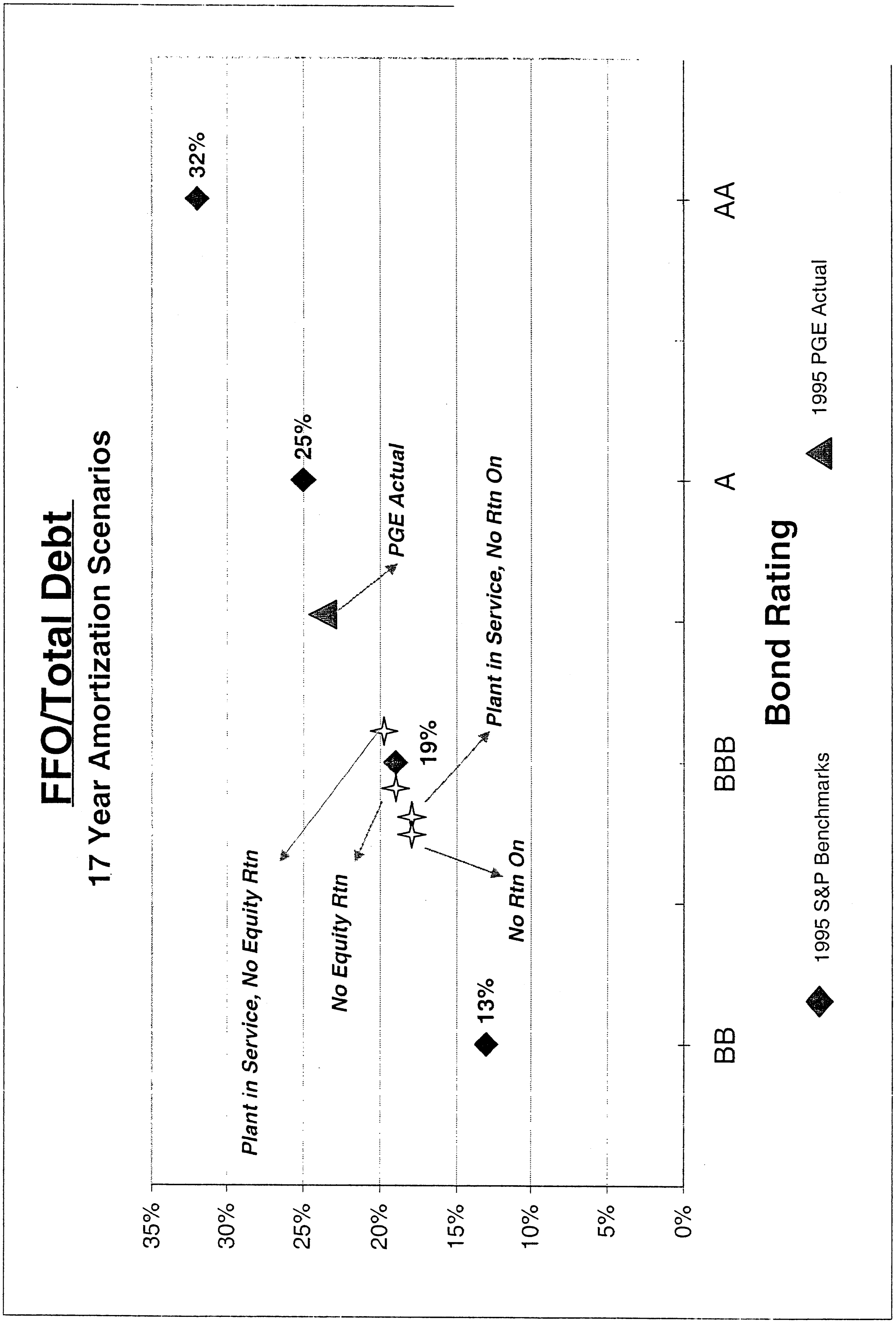
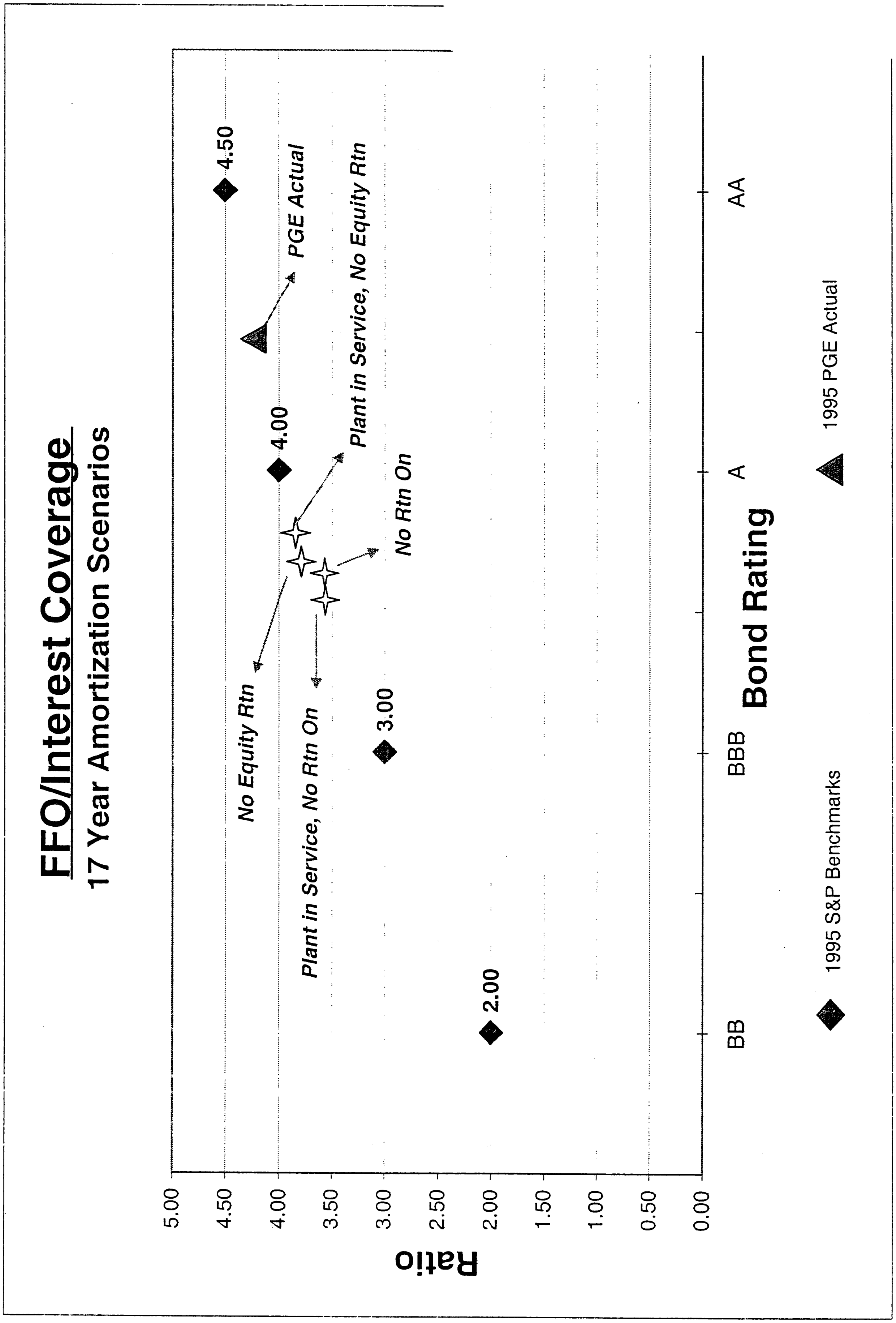
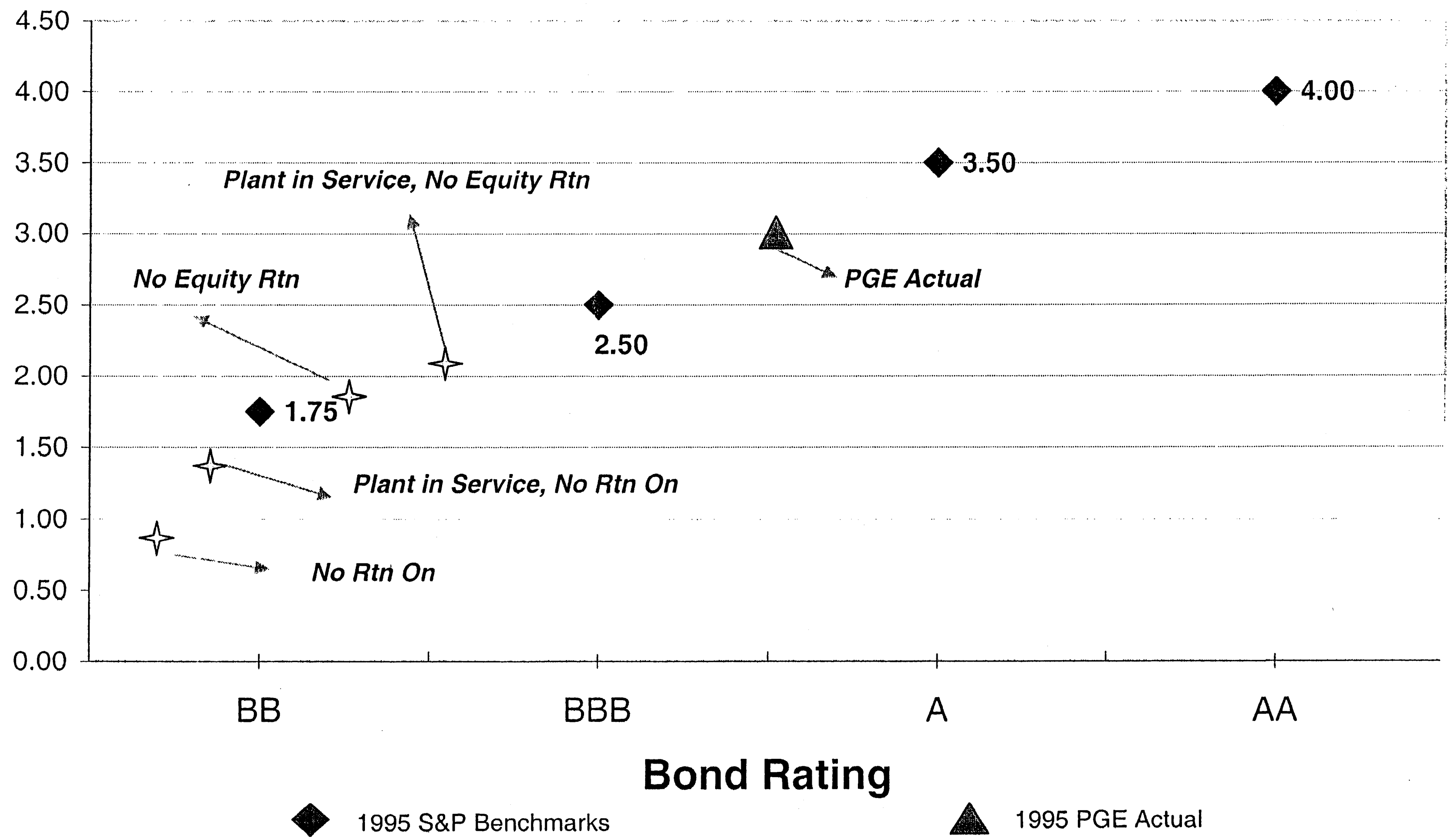
1995 S&P Benchmarks	AA	A	BBB	BB	Calculated from 1995 10-K	17 Year Amortization Scenarios: No "return on"	No "equity return"	Plant in Service, no "return on"	Plant in Service, no "equity return"
FFO/Debt									
Above	26%	19%	14%	11%					
Average	32%	25%	19%	13%	22.43%	17.97%	18.80%	17.97%	19.13%
Below	--	34%	29%	20%					
Interest Coverage									
Above	4.00	3.25	2.25	1.75					
Average	4.50	4.00	3.00	2.00	4.16	3.53	3.65	3.53	3.69
Below	--	5.00	4.00	2.75					
Pretax Int Cov									
Above	3.50	2.75	1.75	1.25					
Average	4.00	3.50	2.50	1.75	3.01	0.95	1.85	1.46	2.14
Below	--	4.50	3.50	2.50					
Total Debt/Cap									
Above	47%	52%	59%	65%					
Average	42%	47%	54%	60%	56.18%	58.98%	57.72%	58.26%	57.33%
Below	--	41%	48%	54%					
Net CashFlow/Cap Ex									
Above	90%	70%	45%	30%					
Average	110%	85%	60%	50%	90.75%	66.62%	71.12%	66.62%	72.91%
Below	--	105%	80%	60%					

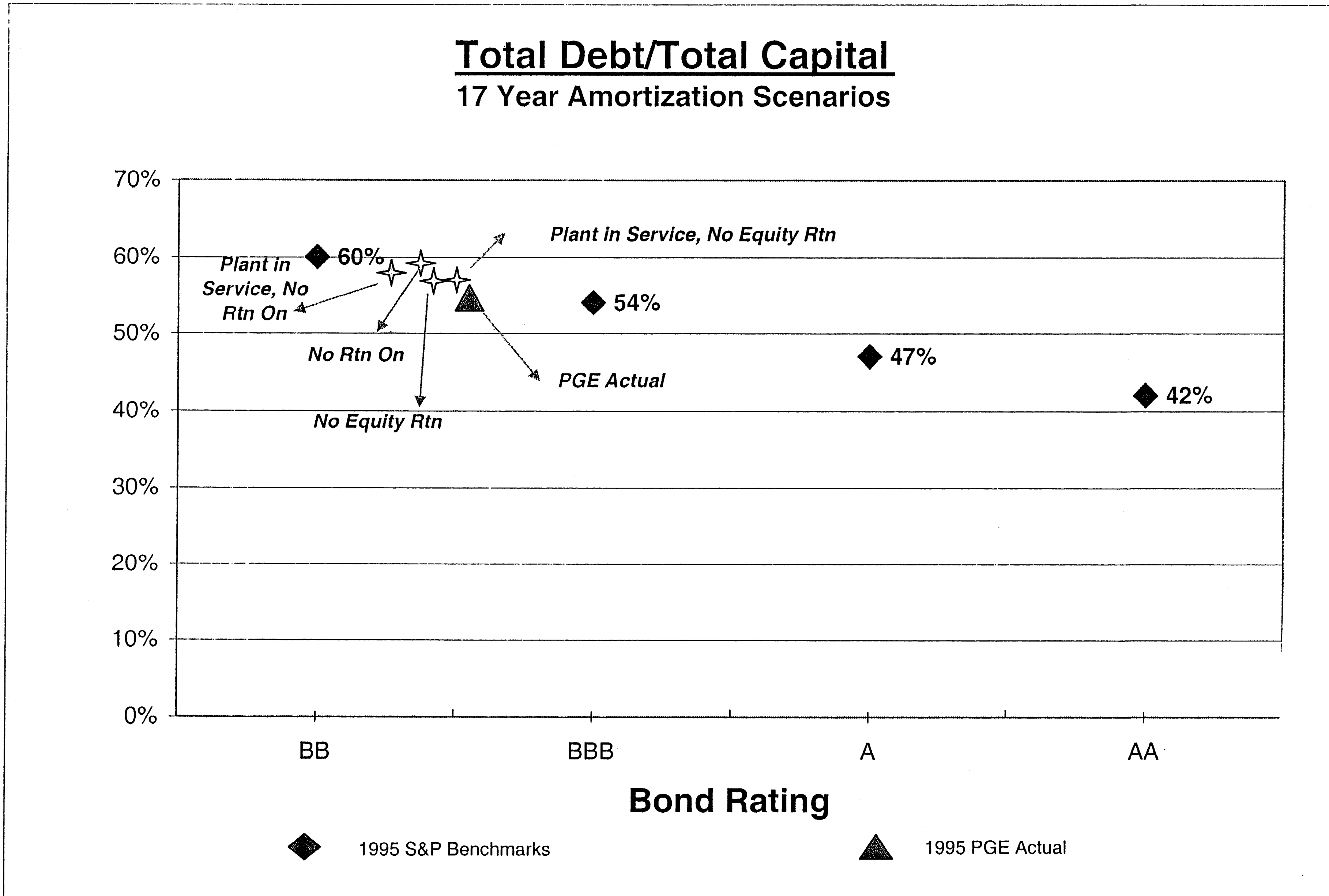

FFO/Total Debt
17 Year Amortization Scenarios
35%
30%
25%
20%
15%
10%
5%
0%
32%
25%
19%
13%
PGE Actual
Plant in Service, No Rtn On
Plant in Service, No Equity Rtn
No Equity Rtn
No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

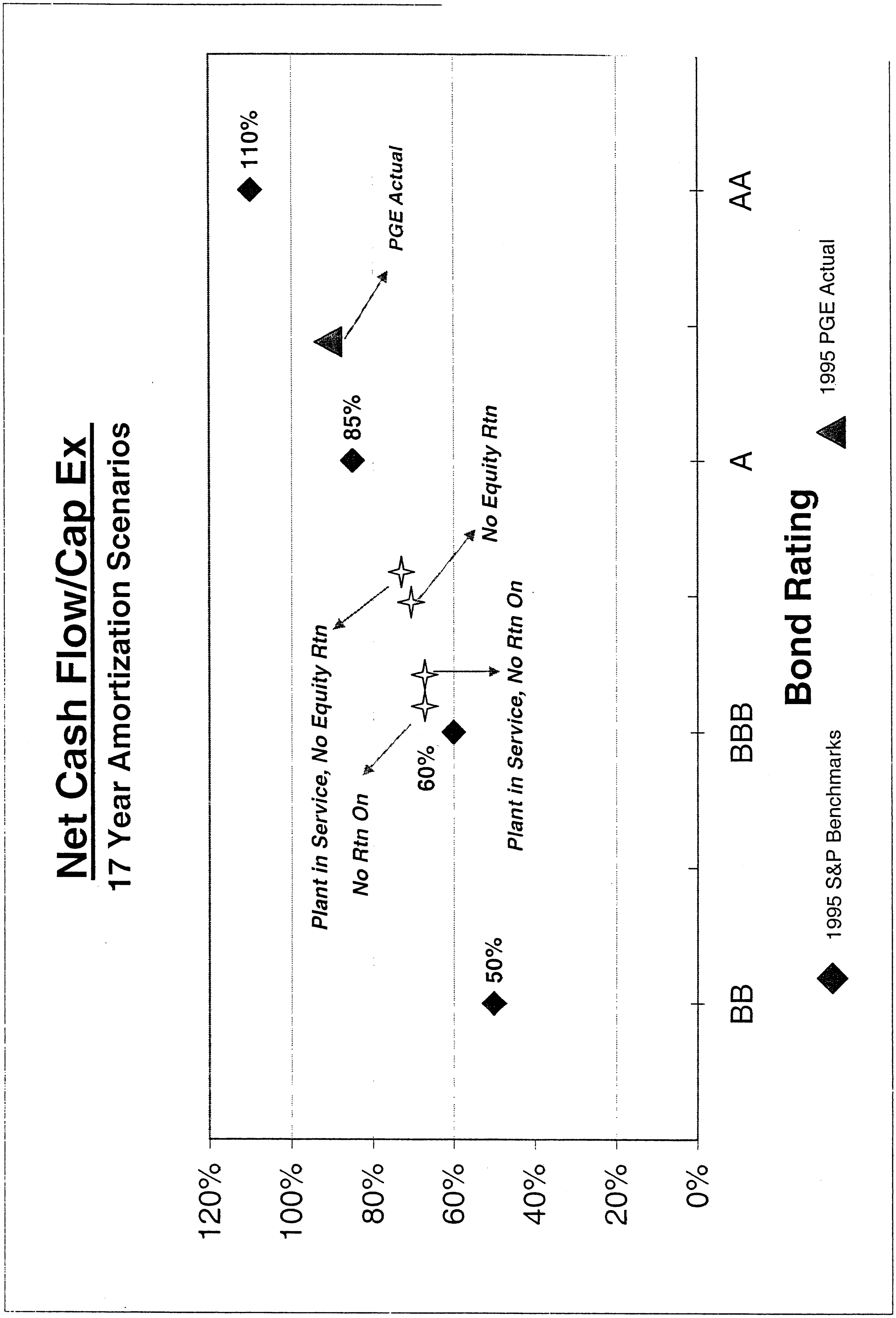

FFO/Interest Coverage
17 Year Amortization Scenarios
Ratio
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
4.50
4.00
3.00
2.00
PGE Actual
Plant in Service, No Equity Rtn
No Rtn On
No Equity Rtn
Plant in Service, No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

Pretax Interest Coverage

17 Year Amortization Scenarios




Total Debt/Total Capital
17 Year Amortization Scenarios
70%
60%
50%
40%
30%
20%
10%
0%
60%
54%
47%
42%
Plant in Service, No Rtn On
No Rtn On
No Equity Rtn
Plant in Service, No Equity Rtn
PGE Actual
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual


Net Cash Flow/Cap Ex
17 Year Amortization Scenarios
120%
100%
80%
60%
40%
20%
0%
110%
85%
60%
50%
PGE Actual
No Equity Rtn
Plant in Service, No Equity Rtn
No Rtn On
Plant in Service, No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

Research:
Portland General Electric Co.

Publication date: 26-Jan-2005
Primary Credit Analyst(s): Swami Venkataraman, CFA, San Francisco (1) 415-371-5071; swami_venkataraman@standardandpoors.com

Corporate Credit Rating

BBB+/Watch Neg/A-2

Business Profile

1 2 3 4 5 6 7 8 9

Debt maturities:
Year $ millions
2005 30
2006 11
2007 70
2008 0
Thereafter 816
Bank lines/Liquid assets:
Portland General Electric (PGE) has a $50 million, 364-day revolving credit facility, maturing May 2005, and $100 million, three-year facility, maturing May 2007. Both facilities are secured by first mortgage bonds.
Collateralization:
As of Sept. 30, 2004, PGE had $923 million in long-term debt, of which $538 million was first mortgage bonds. Substantially all utility property is pledged under the first mortgage indenture. Unsecured debt at PGE is materially disadvantaged and is rated one notch below the corporate credit rating.

Outstanding Rating(s)

Portland General Electric Co.

Sr unsecd debt	
Local currency	BBB/Watch Neg
Sr secd debt	
Local currency	BBB+/Watch Neg
CP	
Local currency	A-2
Sub debt	
Local currency	BBB/Watch Neg
Pfd stk	
Local currency	BBB-/Watch Neg

Corporate Credit Rating History

Mar. 18, 1996	A/A-1
Dec. 7, 2001	BBB+/A-2

Major Rating Factors

Strengths:

- Ring-fenced structure isolates PGE's credit quality from Enron's
- The requirement to maintain a 48% equity layer at PGE provides for a strong capital structure
- The resource valuation mechanism (RVM) allows for power procurement costs to be

adjusted annually

- Consistent financial performance

Weaknesses:

- Potential acquisition by Oregon Electric that would significantly increase leverage on a consolidated basis
- Continued exposure to hydro risk since the RVM assumes average water conditions
- Exposure to litigation risk on cost recovery associated with Trojan nuclear plant

Rationale

Standard & Poor's Ratings Services affirmed its ratings on Portland General Electric Co. (PGE). All ratings remain on CreditWatch with negative implications to reflect Oregon Electric Utility Co. (Oregon Electric) LLC's filing with the Oregon Public Utility Commission (OPUC) on March 8, 2004, to purchase 100% of PGE from Enron Corp. for about $2.35 billion, including the assumption of about $1.1 billion in debt and preferred stock. The final offer may be adjusted to reflect PGE's financial performance between Jan. 1, 2003, and the date of the sale's closing. Based on filings with the OPUC, Oregon Electric will need approximately $1.205 billion to complete the transaction, which is expected to be funded through a combination of $525 million of equity and $680 million of debt. PGE is also expected to dividend about $250 million to Oregon Electric upon completion of the acquisition.

The acquisition will result in a heavily leveraged consolidated balance sheet for PGE and Oregon Electric. Accordingly, Standard & Poor's expects that PGE's ratings will be downgraded. However, based upon the overall financing plan, Standard & Poor's expects that following the acquisition, PGE will be able to maintain investment grade ratings. Key to this is Standard & Poor's expectation that OPUC, as part of the approval process, will require that all dividends from PGE be used to service and pay down Oregon Electric's debt over the next several years. Even in the absence of such a requirement, Texas Pacific Group's (TPG) management has committed to do so. This should result in more than $250 million of debt reduction on a consolidated basis in the first five years following the transaction closing. Standard & Poor's does not expect TPG to have any current income needs from the investment. Also important is the continued supportive regulatory regime in Oregon and the 48% equity layer requirement at PGE.

The Enron bankruptcy court approved the sale on Feb. 5, 2004, following the completion of an "overbid" process in which other potential buyers had the opportunity to submit superior bids; however, no other bids were submitted. The transaction requires OPUC, Federal Energy Regulatory Commission, Nuclear Regulatory Commission, and other regulatory agencies' approval prior to closing. Hearings at OPUC were completed in December 2004 and a decision is expected as early as February 2005. Oregon Electric has offered $43 million in rate reductions to customers over five years starting in 2007.

Oregon Electric is an Oregon limited liability company backed by investment funds managed by TPG, a private equity investment firm with about $13 billion under management. The proposed transaction will be structured so as to prevent Oregon Electric from becoming subject to the Public Utility Holding Company Act (PUHCA). Accordingly, Oregon Electric will be composed of three groups: (1) "local applicants," consisting of a managing member LLC--owned by five prominent local businessmen and civic leaders--who will own a 0.5% economic interest in Oregon Electric and 95% of the voting control; (2) "TPG applicants," comprised of two investment funds managed by TPG, which will own a 79.9% economic interest in Oregon Electric and 5% of the voting control, along with consent rights on certain major corporate decisions; and (3) passive investors, who will own a 19.6% economic interest in Oregon Electric but have no voting control. These include the Bill & Melinda Gates Foundation and a fund managed by Oaktree Capital. With current management expected to remain in place, Standard & Poor's believes that the new board has an appropriate mix of local presence and utility industry expertise.

allows for the annual reset of rates at the beginning of each year based on the company's forecast of net variable power costs for that year. PGE has 1,979 MW of efficient low-cost generation resources, comprised of a mix of hydro, coal, and gas-fired generation. PGE also benefits from cheap hydropower purchases from the Columbia River power system and Bonneville Power Administration. However, PGE must purchase a large amount, approximately 30%, of its energy requirements from the wholesale market, which constitutes the utility's principal business risk. This risk is compounded by the predominance of hydroelectric power in its supply portfolio. PGE has filed an integrated resource plan (IRP) with OPUC, which details a plan to acquire long-term resources to cover the existing short position and includes a 400-MW gas-fired combined cycle power plant at Port Westward, Ore.

PGE's financial performance has been strong, with adjusted funds from operations coverage of interest expected at about 4.6x for 2004 and about 4.0x going forward. Adjusted total debt-to-capitalization is expected to be about 53.2% as of Dec. 31, 2004, and to remain fairly flat going forward. If the acquisition by Oregon Electric is consummated, the adjusted consolidated financial profile will change significantly and PGE's ratings will be downgraded. However, the 48% minimum equity layer mandated by OPUC and the strong, proactive regulatory history in Oregon will likely allow PGE to maintain investment-grade ratings.

The contract for the sale of PGE to Oregon Electric indemnifies Oregon Electric from any liabilities arising from the Enron bankruptcy to the extent of the purchase price ($1.25 billion). This includes matters such as income taxes, retiree health benefits, and Enron pension plans. Oregon Electric is also indemnified with respect to FERC- and California-related legal claims for up to $125 million (of which $34 million has already been exercised).

In 1993, PGE shut down the Trojan nuclear plant as part of its least cost planning process and the OPUC allowed PGE to collect a return on and a majority of its investment in the plant. Lawsuits have been filed seeking to require PGE to refund $260 million of funds collected that represent a return on its investment in Trojan. Proceedings are currently underway both at the Marion County Circuit Court (class action cases) and the OPUC (remand of previous rate cases). Given the uncertainty over the outcome and timing of the proceedings and the likely appeal process, Standard & Poor's treats the potential outcome of the lawsuit and rate proceedings as only a contingent liability at this point. Negative financial impact from these proceedings, if any, will be incorporated by Standard & Poor's when determining the appropriateness of PGE's ratings. Even prior to a final non-appealable verdict in the matter, an initial judgment in the class-action case that is unfavorable to PGE could require PGE to post collateral toward the amount of the refund ordered.

Short-term credit factors.

The rating on PGE's short-term debt of 'A-2' incorporates adequate liquidity, limited requirement for external borrowings to fund capital expenditure requirements, and the expectation that the utility will continue to generate stable cash flow.

The RVM in Oregon allows for the annual reset of rates based on PGE's forecast of net variable power costs for that year. By each November, when the RVM is set, 90%-95% of PGE's open position is filled for the following calendar year, under an average water assumption. Thus, the main liquidity risk from power supply costs arises from hydro variations that are not forecast by November. PGE does not currently have a PCA or a hydro cost deferral mechanism to pass this risk on to customers, although the company has filed a request for a hydro adjustment tariff with the OPUC. A ruling from the OPUC is expected in the second quarter of 2005. PGE has maintained access to the capital markets through the Enron bankruptcy. PGE has $150 million in unsecured, revolving bank lines of credit--a $50 million, 364-day line, and an additional $100 million, three-year line, maturing in May 2005 and May 2007, respectively. PGE previously had a $150 million, 364-day line secured by first mortgage bonds. The new lines reflect increased market confidence that PGE is now isolated from the risks surrounding the Enron bankruptcy, particularly after the sale to Oregon Electric through the auction process. $1 million was outstanding in the form of letters of credit as of Sept. 30, 2004, while cash on hand totaled $199 million.

Throughout the Enron bankruptcy, PGE has maintained cash balances that are higher than historical levels. This is expected to come down once the acquisition by Oregon Electric closes, given that PGE will dividend approximately $250 million to Oregon Electric. However, Standard & Poor's expects that PGE would maintain sufficient liquidity for its operations, supported by internally generated cash, a bank line of credit, and issuance of long-term debt as necessary.

Debt maturities are small and easily manageable, at $30 million and $11 million for 2005 and 2006, respectively. Cash from operations is generally expected to be sufficient to meet capital expenditures except in 2006, when some external borrowing will be required for the Port Westward combined cycle gas-fired project planned under PGE's IRP.

The bank lines have covenants that limit indebtedness to 60% of total capitalization and require an interest coverage ratio of 3x. As of Sept. 30, 2004, these ratios stood at 41.5% and 6.34x, respectively.

Table 1 Portland General Electric--Peer Comparison

	--Average of past three fiscal years--				
	Portland General Electric Co.	**Great Plains Energy Inc.**	**IDACORP Inc.**	**Puget Energy Inc.**	**Avista Corp.**
Rating	BBB+/Watch Neg/A-2	BBB/Stable	BBB+/Stable/A-2	BBB-/Positive	BB+/Stable
($ in millions)					
Sales	2,218.0	1,824.4	2,466.6	2,590.1	2,704.4
Net income from continuing operations	48.3	80.9	77.7	115.3	45.1
Funds from operations (FFO)	245.7	340.2	232.1	401.5	121.4
Capital expenditures	178.3	179.4	155.9	256.2	153.2
Cash and equivalents	56.0	69.6	61.6	98.8	168.8
Total debt	1,039.3	1,456.5	1,171.3	2,658.2	1,202.2
Preferred stock	18.7	39.0	69.9	71.7	32.6
Common equity	1,134.3	892.2	870.0	1,513.6	728.1
Total capital	2,192.3	2,387.6	2,111.2	4,250.9	1,962.9
Ratios					
Adjusted EBIT interest coverage (x)	1.9	2.3	2.2	1.8	1.7
Adjusted FFO interest coverage (x)	3.5	3.7	4.4	2.6	2.1
Adjusted FFO/avg. total debt (%)	20.4	20.3	19.7	12.8	10.0
Net cash flow/capital expenditures (%)	129.4	128.6	105.0	114.3	62.9
Adjusted total debt/capital (%)	51.8	65.6	55.9	66.9	62.9
Return on common equity (%)	4.1	8.6	9.0	7.1	5.1
Common dividend payout (%)	28.6	135.2	87.9	93.8	53.5

Table 2 Portland General Electric Co.--Financial Summary

	--Fiscal year ended Dec. 31--				
Rating history	BBB+/Developing/A-2	BBB+/Developing/A-2	BBB+/Watch Neg/A-2	A/Watch Neg/A-1	A/Watch Neg/A-1
	2003	2002	2001	2000	1999
($ in millions)					
Sales	1,752.0	1,855.0	3,047.0	2,253.0	1,378.0
Net income from continuing operations	56.0	66.0	23.0	141.0	128.0
Funds from operations (FFO)	287.0	241.0	209.0	339.0	264.0
Capital expenditures	167.0	165.0	203.0	173.0	188.0
Cash and equivalents	109.0	51.0	8.0	60.0	0.0
Total debt	983.0	1,019.0	1,116.0	866.0	999.0
Preferred stock	0.0	27.0	29.0	30.0	30.0
Common equity	1,184.0	1,129.0	1,090.0	1,099.0	1,041.0
Total capital	2,167.0	2,175.0	2,235.0	1,995.0	2,070.0
Ratios					
Adjusted EBIT interest coverage (x)	2.1	2.5	1.2	3.4	3.2
Adjusted FFO interest coverage (x)	3.8	3.6	3.1	4.4	3.7
Adjusted FFO/average total debt (%)	24.2	19.3	17.8	29.7	24.0
Net cash flow/capital expenditures (%)	171.3	144.8	82.3	148.0	96.3
Adjusted total debt/capital (%)	49.9	51.3	54.0	49.7	53.6
Return on common equity (%)	4.8	5.8	1.6	13.0	12.4
Common dividend payout (%)	0.0	0.0	190.5	58.3	64.3

UE-88 REMAND / PGE EXHIBIT / 6400
HAGER

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

WORK PAPERS

Patrick G. Hager

February 15, 2005

Work Papers

Table of Contents

PORTLAND GENERAL ELECTRIC
FINANCIAL FORECAST

Financial Ratios	Calculated from 1995 10-K
FFO / Interest Coverage	
Net Income	81,036
Adjustments:	
Add: Depreciation	
Add: Amortization	143,619
Add: Deferred Income Tax	(9,555)
Add: Deferred ITC	(5,549)
Less: AFDC(Debt and Equity)	(11,065)
Less: Other non-cash credits to income (PCA and PRM activities)	49,567
Less: Equity Income	
Cash Flow From Operations	248,053
Incurred Interest	
Total Interest Charges	79,128
Less: Interest Charges on QUIDS	(6,188)
Less: AFDC - Debt	7,808
Total Interest Incurred	80,749
Cash Flow From Operations + Total Interest Incurred	328,802
FFO / Interest Coverage Ratio	**4.16**
Pre-tax Interest Coverage Ratio	
Net Income	81,036
Adjustments:	
Add: Gross Interest Expense	79,128
Add: Income Taxes	89,064
Less: AFDC Equity and Debt	(11,065)
Less: Equity Income	
Adjusted Earnings Before Interest & Taxes	238,163
Total Interest Incurred	79,128
Pre-tax Interest Coverage Ratio	**3.01**

*** 1995 as estimate in PGE Exhibit 2300**

Financial Ratios	Calculated from 1995 10-K
Total Debt / Total Capitalization	
LTD (excluding conservation bonds and current portion of LTD)	890,556
Less: 30% of QUIDS Balance	(23)
Add: Current Portion of long term debt (2) (excluding Conservation Bonds	95,114
Add: Short Term Debt Balance	170,248
Total debt	1,155,896
Preferred Stock	40
Common Stock	191,301
Other Paid In Capital	574,468
Retained Earnings	135,885
Accumulated Other Comprehensive Income	
Total Shareholder's Equity	901,694
Add: LTD (excluding conservation bonds and current portion)	890,556
Add: Current LTD (excluding conservation bonds)	95,114
Add: Short term debt balance	170,248
Total Capitalization	2,057,612
Total Debt / Total Capitalization	**56.18%**
FFO / AverageTotal Debt	
Funds From Operations	248,053
Average Total long term debt	1,105,907
FFO / Total Debt	**22.43%**
Debt/Equity	
Common Equity	933,148
long term debt (2) (excludes LTD w/in 1 Year, includes 100% Quids)	890,556
Preferred Stock (excludes sinking fund)	40,000
Total Capitalization - OPUC	1,863,704
Common Equity Ratio - Per OPUC	**50.07%**
Add 30% of QUIDs	(23)
Cap calculation changes for Rating Agency	
Add Long-Term Debt due within one year	105,114
Add Preferred Sinking Fund	
Add Short-Term Debt	170,248
Total Capitalization - Rating Agency	2,139,066
Common Equity Ratio - Per Rating Agency	**43.62%**

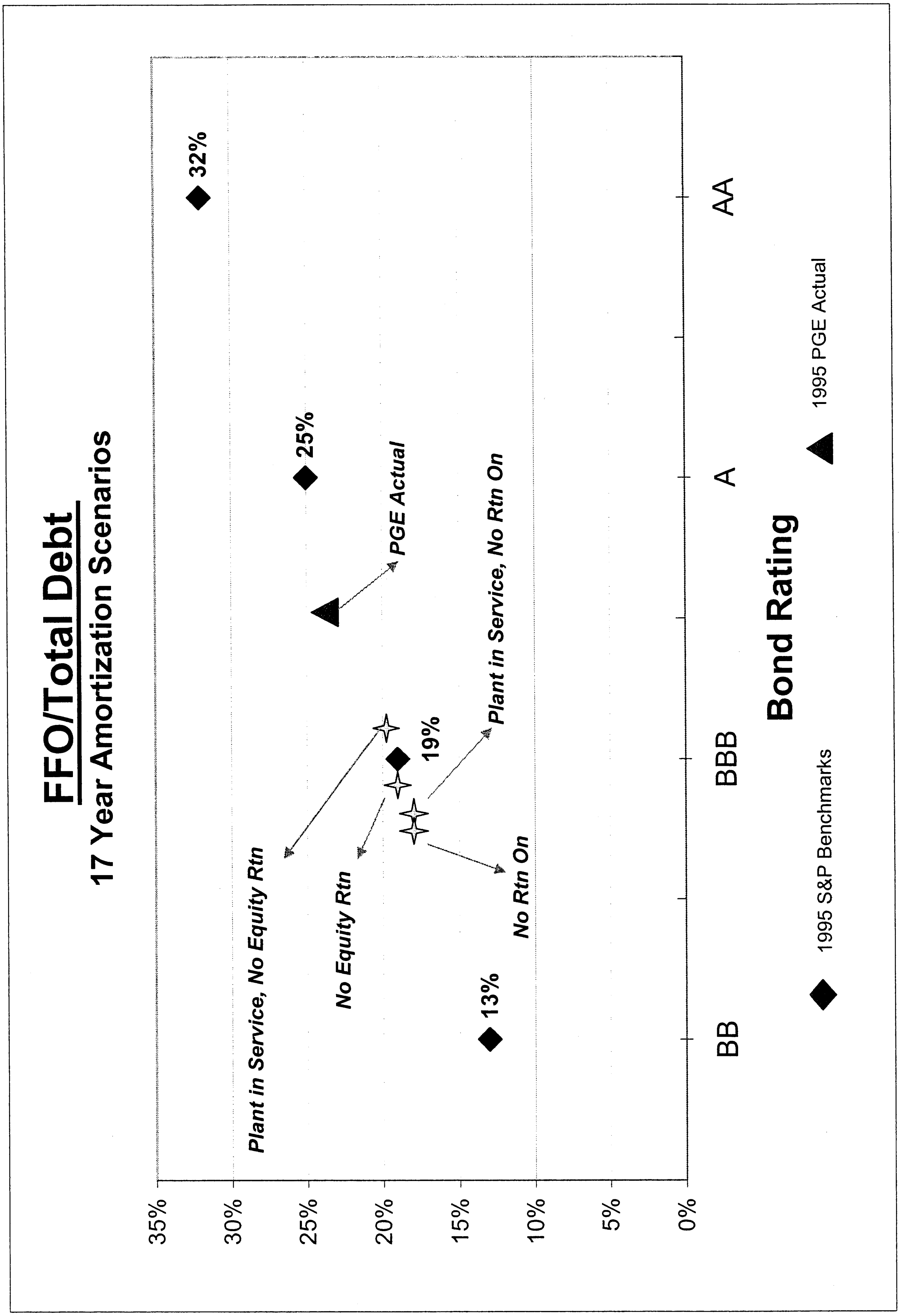
*** 1995 as estimate in PGE Exhibit 2300**

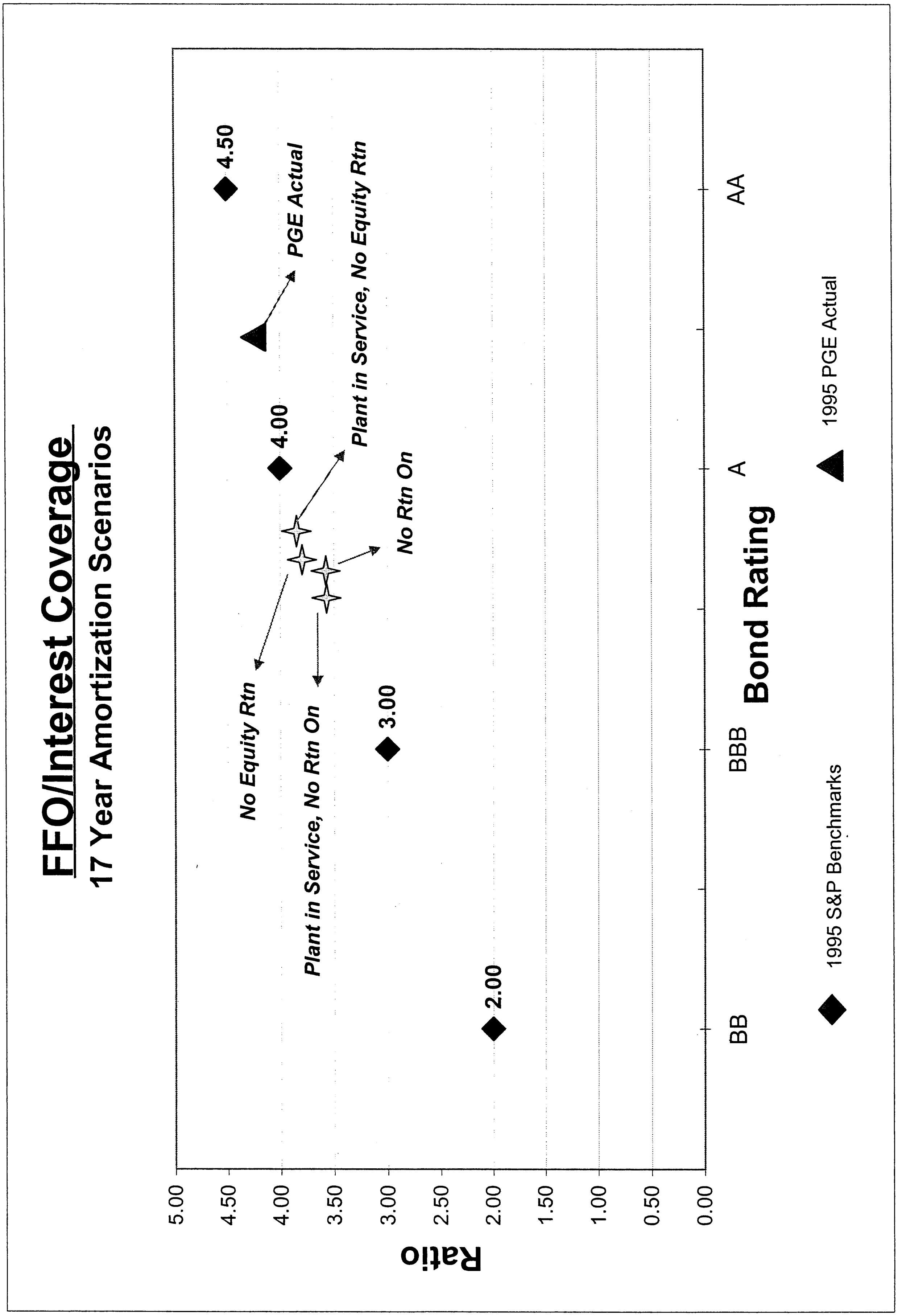
Financial Ratios	Calculated from 1995 10-K
Net Cash Flow / Capital Expenditures	
Funds From Operations	248,053
Less: Dividends Paid	(62,396)
Net Cash Flow	185,657
Cash Flows from Investing Activites	215,645
Less: AFDC(Debt and Equity)	(11,065)
Capital Expenditures	204,580
Net Cash Flow / Capital Expenditures	**90.75%**

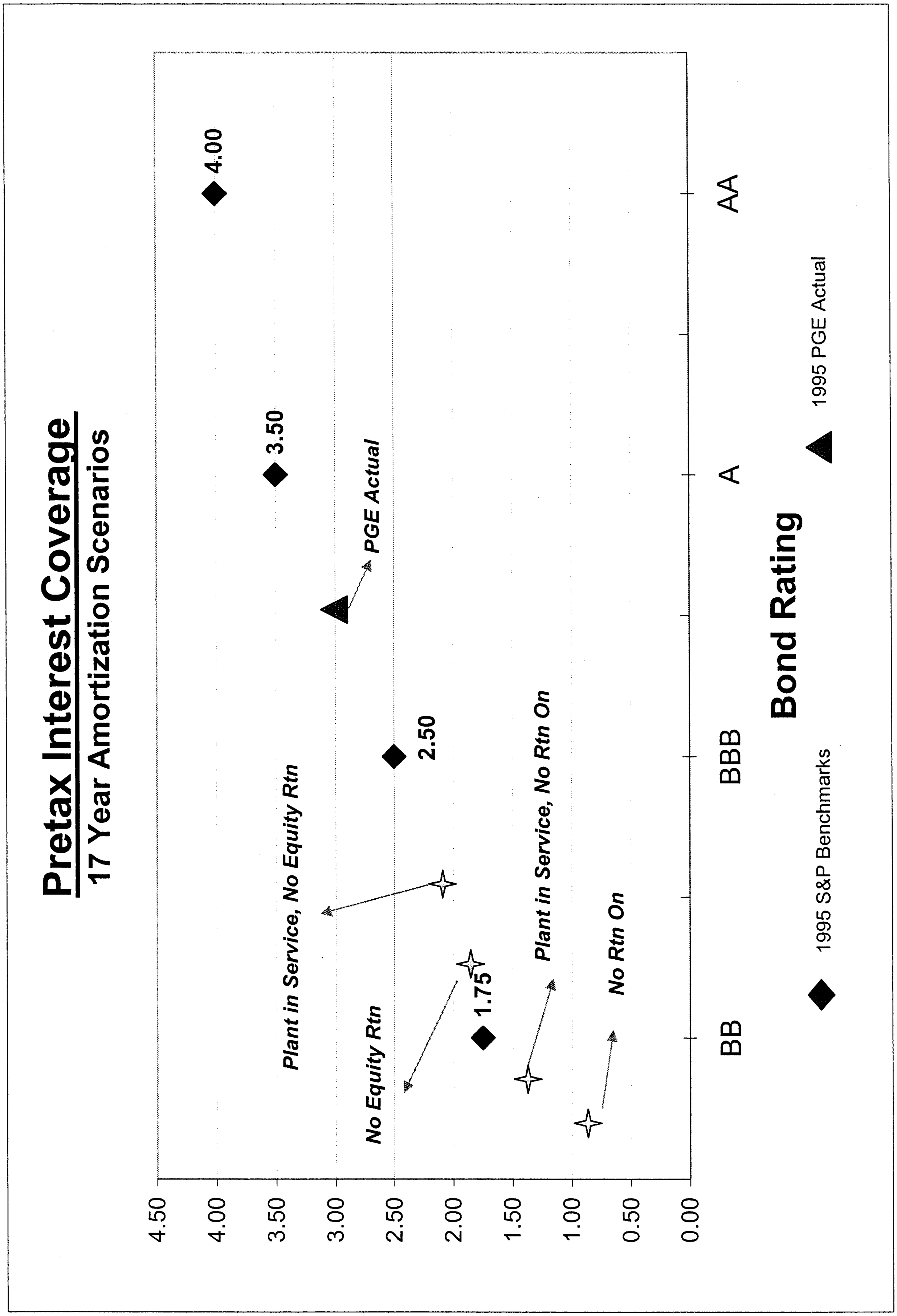
*** 1995 as estimate in PGE Exhibit 2300**

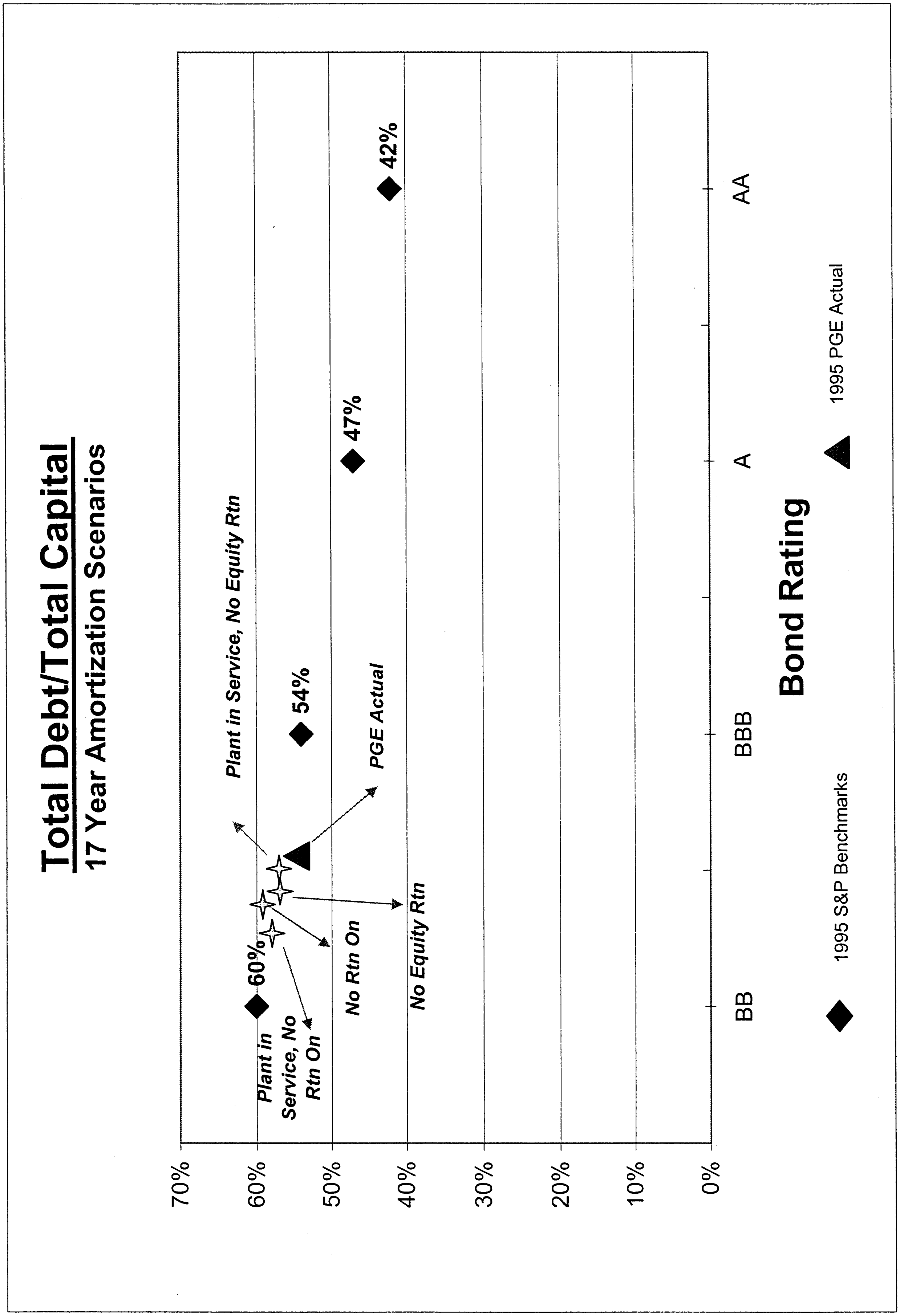
G:\RATECASE\OPUC\DOCKETS\UE-88 Remand\Testimony\CoC - Hager\[Ratio Calcs_2_09_05.xls]Graphs

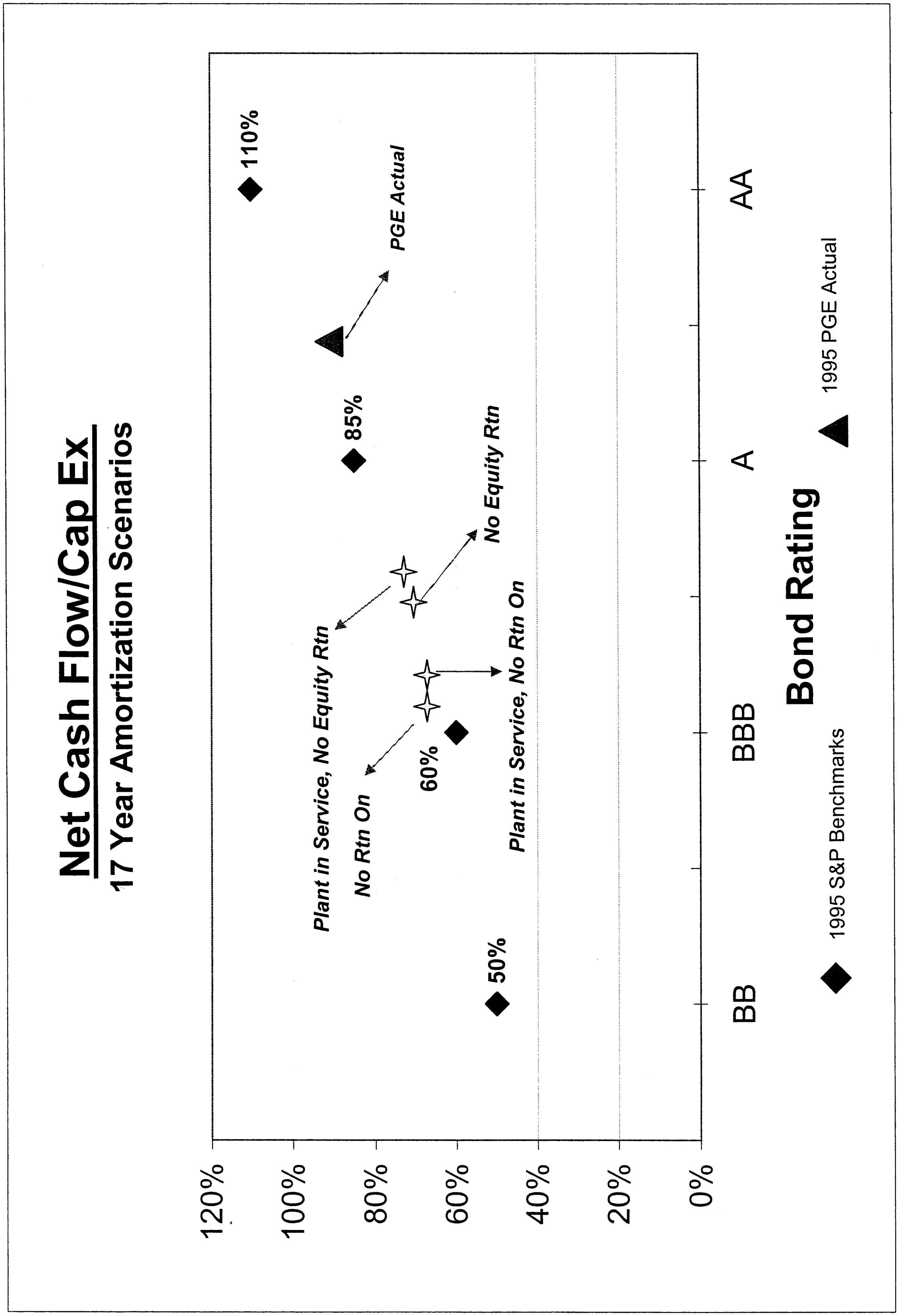
1995 S&P Benchmarks	AA	A	BBB	BB	Calculated from 1995 10-K	17 Year Amortization Scenarios: No "return on"	No "equity return"	Plant in Service, no "return on"	Plant in Service, no "equity return"
FFO/Debt									
Above	26%	19%	14%	11%					
Average	32%	25%	19%	13%	22.43%	17.97%	18.80%	17.97%	19.13%
Below	--	34%	29%	20%					
Interest Coverage									
Above	4.00	3.25	2.25	1.75					
Average	4.50	4.00	3.00	2.00	4.16	3.53	3.65	3.53	3.69
Below	--	5.00	4.00	2.75					
Pretax Int Cov									
Above	3.50	2.75	1.75	1.25					
Average	4.00	3.50	2.50	1.75	3.01	0.95	1.85	1.46	2.14
Below	--	4.50	3.50	2.50					
Total Debt/Cap									
Above	47%	52%	59%	65%					
Average	42%	47%	54%	60%	56.18%	58.98%	57.72%	58.26%	57.33%
Below	--	41%	48%	54%					
Net CashFlow/Cap Ex									
Above	90%	70%	45%	30%					
Average	110%	85%	60%	50%	90.75%	66.62%	71.12%	66.62%	72.91%
Below	--	105%	80%	60%					


FFO/Total Debt
17 Year Amortization Scenarios
35%
30%
25%
20%
15%
10%
5%
0%
32%
25%
19%
13%
PGE Actual
Plant in Service, No Rtn On
Plant in Service, No Equity Rtn
No Equity Rtn
No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual


FFO/Interest Coverage
17 Year Amortization Scenarios
Ratio
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
4.50
4.00
3.00
2.00
PGE Actual
Plant in Service, No Equity Rtn
No Rtn On
No Equity Rtn
Plant in Service, No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual


Pretax Interest Coverage
17 Year Amortization Scenarios
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
4.00
3.50
PGE Actual
2.50
1.75
Plant in Service, No Equity Rtn
No Equity Rtn
Plant in Service, No Rtn On
No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual


Total Debt/Total Capital
17 Year Amortization Scenarios
70%
60%
50%
40%
30%
20%
10%
0%
BB
BBB
A
AA
60%
54%
47%
42%
Plant in Service, No Equity Rtn
PGE Actual
No Rtn On
No Equity Rtn
Plant in Service, No Rtn On
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual


Net Cash Flow/Cap Ex
17 Year Amortization Scenarios
120%
100%
80%
60%
40%
20%
0%
110%
85%
60%
50%
PGE Actual
No Equity Rtn
Plant in Service, No Rtn On
Plant in Service, No Equity Rtn
No Rtn On
BB
BBB
A
AA
Bond Rating
1995 S&P Benchmarks
1995 PGE Actual

FAS 90 Impairment Test Results
For Financial Ratio Analysis

Scenario:	Balances at 4/1/1995 Before Impairment:				Pre-Tax
	FAS 71	FAS 90	In Service	Total	Impairment
1 Year Amortization Scenarios:					
1 Year Amortization (no "return on")	17,582,008	322,580,427	-	340,162,435	23,894,846
1 Year Amortization (no "equity return")	17,582,008	322,580,427	-	340,162,435	12,529,860
1 Year Amortization (Plant in Service, no "return on")	17,582,008	242,580,427	80,000,000	340,162,435	17,968,921
1 Year Amortization (Plant in Service, no "equity return")	17,582,008	242,580,427	80,000,000	340,162,435	9,422,453
17 Year Amortization Scenarios:					
17 Year Amortization (no "return on")	17,582,008	322,580,427	-	340,162,435	149,494,432
17 Year Amortization (no "equity return")	17,582,008	322,580,427	-	340,162,435	78,391,143
17 Year Amortization (Plant in Service, no "return on")	17,582,008	242,580,427	80,000,000	340,162,435	112,419,788
17 Year Amortization (Plant in Service, no "equity return'	17,582,008	242,580,427	80,000,000	340,162,435	58,950,126

FAS 90 Impairment Test Results
For Financial Ratio Analysis

Scenario:	**Calculations for Rating Agency Ratio Changes Impairment Effects (at 4/1/1995)** Pre-Tax Loss	Tax Benefit	Income / Retained Earnings	**9-month effects here only** On-Going Pre-Tax Loss	On-Going After-Tax Loss
1 Year Amortization Scenarios:					
1 Year Amortization (no "return on")	23,894,846	(9,557,939)	14,336,908	13,317,359	7,990,416
1 Year Amortization (no "equity return")	12,529,860	(5,011,944)	7,517,916	13,317,359	7,990,416
1 Year Amortization (Plant in Service, no "return on")	17,968,921	(7,187,568)	10,781,352	10,185,359	6,111,216
1 Year Amortization (Plant in Service, no "equity return")	9,422,453	(3,768,981)	5,653,472	10,185,359	6,111,216
17 Year Amortization Scenarios:					
17 Year Amortization (no "return on")	149,494,432	(59,797,773)	89,696,659	13,317,359	7,990,416
17 Year Amortization (no "equity return")	78,391,143	(31,356,457)	47,034,686	13,317,359	7,990,416
17 Year Amortization (Plant in Service, no "return on")	112,419,788	(44,967,915)	67,451,873	10,185,359	6,111,216
17 Year Amortization (Plant in Service, no "equity return'	58,950,126	(23,580,050)	35,370,076	10,185,359	6,111,216

FAS 90 Impairment Test Results
For Financial Ratio Analysis

Scenario:	9 months from 4/1/1995 1995 Actual Recovery of	1995 Actual Return On	1995 Actual Cash Flow	9 months from 4/1/1995 1995 Scenario Recovery of	1995 Scenario Debt Recovery	1995 Scenario Cash Flow	Delta Cash Flow
1 Year Amortization Scenarios:							
1 Year Amortization (no "return on")	39,139,295	25,229,727	64,369,022	255,121,826	-	255,121,826	190,752,804
1 Year Amortization (no "equity return")	39,139,295	25,229,727	64,369,022	255,121,826	9,205,639	264,327,465	199,958,443
1 Year Amortization (Plant in Service, no "return on")	39,139,295	25,229,727	64,369,022	255,121,826	-	255,121,826	190,752,804
1 Year Amortization (Plant in Service, no "equity return")	39,139,295	25,229,727	64,369,022	255,121,826	12,856,211	267,978,037	203,609,015
17 Year Amortization Scenarios:							
17 Year Amortization (no "return on")	39,139,295	25,229,727	64,369,022	15,007,166	-	15,007,166	(49,361,856)
17 Year Amortization (no "equity return")	39,139,295	25,229,727	64,369,022	15,007,166	9,205,639	24,212,805	(40,156,217)
17 Year Amortization (Plant in Service, no "return on")	39,139,295	25,229,727	64,369,022	15,007,166	-	15,007,166	(49,361,856)
17 Year Amortization (Plant in Service, no "equity return'	39,139,295	25,229,727	64,369,022	15,007,166	12,856,211	27,863,377	(36,505,645)

FAS 90 Impairment Test (No "return on")
Starting with Post UE-88 Writeoff Balance

Trojan Unamortized Balance @ 4/1/1995 (Post UE-88 Writeoff)	$	340,162,435
FAS 71 Portion	$	17,582,008
FAS 90 Portion	$	322,580,427

Discount Rate (Incremental Cost of Debt) 8.0%

17-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization
1995	$ 18,975,319	$ 1,034,236	$ 20,009,555
1996	$ 18,975,319	$ 1,034,236	$ 20,009,555
1997	$ 18,975,319	$ 1,034,236	$ 20,009,555
1998	$ 18,975,319	$ 1,034,236	$ 20,009,555
1999	$ 18,975,319	$ 1,034,236	$ 20,009,555
2000	$ 18,975,319	$ 1,034,236	$ 20,009,555
2001	$ 18,975,319	$ 1,034,236	$ 20,009,555
2002	$ 18,975,319	$ 1,034,236	$ 20,009,555
2003	$ 18,975,319	$ 1,034,236	$ 20,009,555
2004	$ 18,975,319	$ 1,034,236	$ 20,009,555
2005	$ 18,975,319	$ 1,034,236	$ 20,009,555
2006	$ 18,975,319	$ 1,034,236	$ 20,009,555
2007	$ 18,975,319	$ 1,034,236	$ 20,009,555
2008	$ 18,975,319	$ 1,034,236	$ 20,009,555
2009	$ 18,975,319	$ 1,034,236	$ 20,009,555
2010	$ 18,975,319	$ 1,034,236	$ 20,009,555
2011	$ 18,975,319	$ 1,034,236	$ 20,009,555
Total	$ 322,580,427	$ 17,582,008	$ 340,162,435

PV $ 173,085,995

1-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization
1995	$ 322,580,427	$ 17,582,008	$ 340,162,435

PV $ 298,685,581

17 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 322,580,427
PV of FAS 90 Cash Flows	$ 173,085,995
Pre-tax Write-Off	$ 149,494,432
Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 173,085,995
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 190,668,003

1 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 322,580,427
PV of FAS 90 Cash Flows	$ 298,685,581
Pre-tax Write-Off	$ 23,894,846
Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 298,685,581
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 316,267,589

FAS 90 Impairment Test (no "return on")
Reflects Plant in Service Reclass, post UE-88 writeoff

Trojan Unamortized Balance @ 4/1/1995 (Post UE-88 Writeoff)	$ 340,162,435
FAS 71 Portion	$ 17,582,008
Plant in Service Portion	$ 80,000,000
Net FAS 90 Portion	$ 242,580,427

Discount Rate (Incremental Cost of Debt) 8.0%

17-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Plant in Srvc Depreciation	Total Amortization
1995	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
1996	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
1997	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
1998	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
1999	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2000	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2001	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2002	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2003	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2004	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2005	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2006	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2007	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2008	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2009	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2010	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
2011	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555
Total	$ 242,580,427	$ 17,582,008	$ 80,000,000	$ 340,162,435

PV $ 130,160,639

1-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Plant in Srvc Depreciation	Total Amortization
1995	$ 242,580,427	$ 17,582,008	$ 80,000,000	$ 340,162,435

PV $ 224,611,506

17 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 242,580,427
PV of FAS 90 Cash Flows	$ 130,160,639
Pre-tax Write-Off	$ 112,419,788
Unamortized Balances after FAS 90 Write-Off:	
Plant in Service Portion	$ 80,000,000
FAS 90 @ 4/1/1995	$ 130,160,639
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 227,742,647

1 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 242,580,427
PV of FAS 90 Cash Flows	$ 224,611,506
Pre-tax Write-Off	$ 17,968,921
Unamortized Balances after FAS 90 Write-Off:	
Plant in Service Portion	$ 80,000,000
FAS 90 @ 4/1/1995	$ 224,611,506
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 322,193,514

FAS 90 Impairment Test (Debt recovery allowed)
Starting with Post UE-88 Writeoff Balance

Trojan Unamortized Balance @ 4/1/1995 (Post UE-88 Writeoff)	$	340,162,435
FAS 71 Portion	$	17,582,008
FAS 90 Portion	$	322,580,427

Discount Rate (Incremental Cost of Debt)	8.0%
UE-88 Weighted Debt Cost	3.81%

17-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization	FAS 90 Balance	FAS 90 Debt Recovery
1995	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 322,580,427	$ 12,274,185
1996	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 303,605,108	$ 11,552,174
1997	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 284,629,789	$ 10,830,163
1998	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 265,654,469	$ 10,108,153
1999	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 246,679,150	$ 9,386,142
2000	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 227,703,831	$ 8,664,131
2001	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 208,728,512	$ 7,942,120
2002	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 189,753,192	$ 7,220,109
2003	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 170,777,873	$ 6,498,098
2004	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 151,802,554	$ 5,776,087
2005	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 132,827,235	$ 5,054,076
2006	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 113,851,915	$ 4,332,065
2007	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 94,876,596	$ 3,610,054
2008	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 75,901,277	$ 2,888,044
2009	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 56,925,958	$ 2,166,033
2010	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 37,950,638	$ 1,444,022
2011	$ 18,975,319	$ 1,034,236	$ 20,009,555	$ 18,975,319	$ 722,011
Total	$ 322,580,427	$ 17,582,008	$ 340,162,435		$ 110,467,667
PV	$ 173,085,995			PV - 17 years	$ 71,103,289

1-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Total Amortization	YE FAS 90 Balance	FAS 90 Debt Recovery
1995	$ 322,580,427	$ 17,582,008	$ 340,162,435	$ 322,580,427	12,274,185
PV	$ 298,685,581			PV - 1 year	$ 11,364,986

17 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 322,580,427
PV of FAS 90 Cash Flows	$ 244,189,284
Pre-tax Write-Off	$ 78,391,143
Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 244,189,284
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 261,771,292

1 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 322,580,427
PV of FAS 90 Cash Flows	$ 310,050,567
Pre-tax Write-Off	$ 12,529,860
Unamortized Balances after FAS 90 Write-Off:	
FAS 90 @ 4/1/1995	$ 310,050,567
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 327,632,575

FAS 90 Impairment Test (Debt recovery allowed)
Reflects Plant in Service Reclass, post UE-88 writeoff

Trojan Unamortized Balance @ 4/1/1995 (Post UE-88 Writeoff)	$ 340,162,435
FAS 71 Portion	$ 17,582,008
Plant in Service Portion	$ 80,000,000
Net FAS 90 Portion	$ 242,580,427

Discount Rate (Incremental Cost of Debt)	8.0%
UE-88 Weighted Debt Cost	3.81%

17-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Plant in Srvc Depreciation	Total Amortization	FAS 90 Balance	FAS 90 Debt Recovery
1995	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 242,580,427	$ 9,230,185
1996	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 228,310,990	$ 8,687,233
1997	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 214,041,553	$ 8,144,281
1998	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 199,772,116	$ 7,601,329
1999	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 185,502,679	$ 7,058,377
2000	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 171,233,243	$ 6,515,425
2001	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 156,963,806	$ 5,972,473
2002	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 142,694,369	$ 5,429,521
2003	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 128,424,932	$ 4,886,569
2004	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 114,155,495	$ 4,343,617
2005	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 99,886,058	$ 3,800,665
2006	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 85,616,621	$ 3,257,712
2007	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 71,347,184	$ 2,714,760
2008	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 57,077,748	$ 2,171,808
2009	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 42,808,311	$ 1,628,856
2010	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 28,538,874	$ 1,085,904
2011	$ 14,269,437	$ 1,034,236	$ 4,705,882	$ 20,009,555	$ 14,269,437	$ 542,952
Total	$ 242,580,427	$ 17,582,008	$ 80,000,000	$ 340,162,435		$ 83,071,667
PV	$ 130,160,639				PV - 17 years	$ 53,469,662

1-Year Amortization Schedule

Year	FAS 90 Amortization	FAS 71 Amortization	Plant in Srvc Depreciation	Total Amortization	YE FAS 90 Balance	FAS 90 Debt Recovery
1995	$ 242,580,427	$ 17,582,008	$ 80,000,000	$ 340,162,435	$ 242,580,427	9,230,185
PV	$ 224,611,506				PV - 1 year	$ 8,546,468

17 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 242,580,427
PV of FAS 90 Cash Flows	$ 183,630,301
Pre-tax Write-Off	$ 58,950,126
Unamortized Balances after FAS 90 Write-Off:	
Plant in Service Portion	$ 80,000,000
FAS 90 @ 4/1/1995	$ 183,630,301
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 281,212,309

1 Year Amortization Period

FAS 90 Write-Off:	
Pre-tax FAS 90 Balance @ 4/1/1995	$ 242,580,427
PV of FAS 90 Cash Flows	$ 233,157,974
Pre-tax Write-Off	$ 9,422,453
Unamortized Balances after FAS 90 Write-Off:	
Plant in Service Portion	$ 80,000,000
FAS 90 @ 4/1/1995	$ 233,157,974
FAS 71 @ 4/1/1995	$ 17,582,008
Total Unamortized balance after Write-Off	$ 330,739,982

Scenario Financial Ratios
Dollars in 000s

Scenario:	FFO	Interest Charges	Interest Incurred	FFO / Interest	Pre-Tax Income	Pre-Tax Interest Coverage
Base - 1995 Actual (Per 10K)	$ 248,053	$ 79,128	$ 80,749	4.16	$ 238,163	3.01
1 Year Amortization Scenarios:						
1 Year Amortization (no "return on")	$ 438,806	$ 79,128	$ 80,749	6.57	$ 200,951	2.54
1 Year Amortization (no "equity return")	$ 448,011	$ 79,128	$ 80,749	6.68	$ 212,316	2.68
1 Year Amortization (Plant in Service, no "return on")	$ 438,806	$ 79,128	$ 80,749	6.57	$ 210,009	2.65
1 Year Amortization (Plant in Service, no "equity return")	$ 451,662	$ 79,128	$ 80,749	6.73	$ 218,555	2.76
17 Year Amortization Scenarios:						
17 Year Amortization (no "return on")	$ 198,691	$ 79,128	$ 80,749	3.53	$ 75,351	0.95
17 Year Amortization (no "equity return")	$ 207,897	$ 79,128	$ 80,749	3.65	$ 146,454	1.85
17 Year Amortization (Plant in Service, no "return on")	$ 198,691	$ 79,128	$ 80,749	3.53	$ 115,558	1.46
17 Year Amortization (Plant in Service, no "equity return")	$ 211,547	$ 79,128	$ 80,749	3.69	$ 169,028	2.14

Including Effects of a 10% change in cap structure:	FFO	Interest Charges	Interest Incurred	FFO / Interest	Pre-Tax Income	Pre-Tax Interest Coverage
Base - 1995 Actual (Per 10K)	$ 259,837	$ 79,128	$ 80,749	4.30	$ 249,947	3.16
1 Year Amortization Scenarios:						
1 Year Amortization (no "return on")	$ 450,590	$ 79,128	$ 80,749	6.71	$ 212,735	2.69
1 Year Amortization (no "equity return")	$ 459,796	$ 79,128	$ 80,749	6.83	$ 224,100	2.83
1 Year Amortization (Plant in Service, no "return on")	$ 450,590	$ 79,128	$ 80,749	6.71	$ 221,793	2.80
1 Year Amortization (Plant in Service, no "equity return")	$ 463,446	$ 79,128	$ 80,749	6.88	$ 230,339	2.91
17 Year Amortization Scenarios:						
17 Year Amortization (no "return on")	$ 210,475	$ 79,128	$ 80,749	3.68	$ 87,135	1.10
17 Year Amortization (no "equity return")	$ 219,681	$ 79,128	$ 80,749	3.80	$ 158,239	2.00
17 Year Amortization (Plant in Service, no "return on")	$ 210,475	$ 79,128	$ 80,749	3.68	$ 127,342	1.61
17 Year Amortization (Plant in Service, no "equity return")	$ 223,331	$ 79,128	$ 80,749	3.84	$ 180,812	2.29

Scenario Financial Ratios
Dollars in 000s

Scenario:	Long-Term Debt	Equity	Total Cap	Debt / Total Cap	Average Debt	FFO / Debt	OPUC Equity	Tot Cap OPUC	Equity Ratio - OPUC
Base - 1995 Actual (Per 10K)	$ 1,155,896	$ 901,694	$2,057,590	56.18%	$ 1,105,907	22.43%	$933,148	$ 1,863,704	50.1%
1 Year Amortization Scenarios:									
1 Year Amortization (no "return on")	$ 1,155,896	$ 879,367	$2,035,262	56.79%	$ 1,105,907	39.68%	$910,821	$ 1,841,377	49.5%
1 Year Amortization (no "equity return")	$ 1,155,896	$ 886,186	$2,042,081	56.60%	$ 1,105,907	40.51%	$917,640	$ 1,848,196	49.7%
1 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 884,801	$2,040,697	56.64%	$ 1,105,907	39.68%	$916,255	$ 1,846,811	49.6%
1 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 889,929	$2,045,825	56.50%	$ 1,105,907	40.84%	$921,383	$ 1,851,939	49.8%
17 Year Amortization Scenarios:									
17 Year Amortization (no "return on")	$ 1,155,896	$ 804,007	$1,959,902	58.98%	$ 1,105,907	17.97%	$835,461	$ 1,766,017	47.3%
17 Year Amortization (no "equity return")	$ 1,155,896	$ 846,669	$2,002,564	57.72%	$ 1,105,907	18.80%	$878,123	$ 1,808,679	48.6%
17 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 828,131	$1,984,026	58.26%	$ 1,105,907	17.97%	$859,585	$ 1,790,141	48.0%
17 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 860,213	$2,016,108	57.33%	$ 1,105,907	19.13%	$891,667	$ 1,822,223	48.9%

Including Effects of a 10% change in cap structure:	Long-Term Debt	Equity	Total Cap	Debt / Total Cap	Average Debt	FFO / Debt	Equity	Tot Cap OPUC	Equity Ratio - OPUC
Base - 1995 Actual (Per 10K)	$ 1,155,896	$ 908,764	$2,064,660	55.98%	$ 1,105,907	23.50%	$940,218	$ 1,870,774	50.3%
1 Year Amortization Scenarios:									
1 Year Amortization (no "return on")	$ 1,155,896	$ 886,437	$2,042,333	56.60%	$ 1,105,907	40.74%	$917,891	$ 1,848,447	49.7%
1 Year Amortization (no "equity return")	$ 1,155,896	$ 893,256	$2,049,152	56.41%	$ 1,105,907	41.58%	$924,710	$ 1,855,266	49.8%
1 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 891,872	$2,047,767	56.45%	$ 1,105,907	40.74%	$923,326	$ 1,853,882	49.8%
1 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 897,000	$2,052,895	56.31%	$ 1,105,907	41.91%	$928,454	$ 1,859,010	49.9%
17 Year Amortization Scenarios:									
17 Year Amortization (no "return on")	$ 1,155,896	$ 811,077	$1,966,973	58.77%	$ 1,105,907	19.03%	$842,531	$ 1,773,087	47.5%
17 Year Amortization (no "equity return")	$ 1,155,896	$ 853,739	$2,009,635	57.52%	$ 1,105,907	19.86%	$885,193	$ 1,815,749	48.8%
17 Year Amortization (Plant in Service, no "return on")	$ 1,155,896	$ 835,201	$1,991,097	58.05%	$ 1,105,907	19.03%	$866,655	$ 1,797,211	48.2%
17 Year Amortization (Plant in Service, no "equity return")	$ 1,155,896	$ 867,283	$2,023,179	57.13%	$ 1,105,907	20.19%	$898,737	$ 1,829,293	49.1%

Scenario Financial Ratios
Dollars in 000s

Scenario:	Tot Cap Rating Ag	Equity Ratio - Rat	Dividends Paid	Net Cash Flow	Cap Ex	Net Cash Flow / Cap Ex	
Base - 1995 Actual (Per 10K)	$ 2,139,066	43.6%	(62,396)	$185,657	204,580	90.75%	
1 Year Amortization Scenarios:							
1 Year Amortization (no "return on")	$ 2,116,739	43.0%	(253,149)	$185,657	204,580	90.75%	
1 Year Amortization (no "equity return")	$ 2,123,558	43.2%	(262,354)	$185,657	204,580	90.75%	
1 Year Amortization (Plant in Service, no "return on")	$ 2,122,173	43.2%	(253,149)	$185,657	204,580	90.75%	
1 Year Amortization (Plant in Service, no "equity return")	$ 2,127,301	43.3%	(266,005)	$185,657	204,580	90.75%	
17 Year Amortization Scenarios:							
17 Year Amortization (no "return on")	$ 2,041,379	40.9%	(62,396)	$136,295	204,580	66.62%	Assumes ST Debt used
17 Year Amortization (no "equity return")	$ 2,084,041	42.1%	(62,396)	$145,501	204,580	71.12%	to make up cash flow
17 Year Amortization (Plant in Service, no "return on")	$ 2,065,503	41.6%	(62,396)	$136,295	204,580	66.62%	delta for 17-yr cases. Impact not
17 Year Amortization (Plant in Service, no "equity return")	$ 2,097,585	42.5%	(62,396)	$149,151	204,580	72.91%	calc'd on ratios

Including Effects of a 10% change in cap structure:	Tot Cap Rating Ag	Equity Ratio - Rat	Dividends Paid	Net Cash Flow	Cap Ex	Net Cash Flow / Cap Ex	
Base - 1995 Actual (Per 10K)	$ 2,146,136	43.8%	(62,396)	$197,441	204,580	96.51%	
1 Year Amortization Scenarios:							
1 Year Amortization (no "return on")	$ 2,123,809	43.2%	(253,149)	$197,441	204,580	96.51%	
1 Year Amortization (no "equity return")	$ 2,130,628	43.4%	(262,354)	$197,441	204,580	96.51%	
1 Year Amortization (Plant in Service, no "return on")	$ 2,129,244	43.4%	(253,149)	$197,441	204,580	96.51%	
1 Year Amortization (Plant in Service, no "equity return")	$ 2,134,372	43.5%	(266,005)	$197,441	204,580	96.51%	
17 Year Amortization Scenarios:							
17 Year Amortization (no "return on")	$ 2,048,449	41.1%	(62,396)	$148,079	204,580	72.38%	Assumes ST Debt used
17 Year Amortization (no "equity return")	$ 2,091,111	42.3%	(62,396)	$157,285	204,580	76.88%	to make up cash flow
17 Year Amortization (Plant in Service, no "return on")	$ 2,072,573	41.8%	(62,396)	$148,079	204,580	72.38%	delta for 17-yr cases. Impact not
17 Year Amortization (Plant in Service, no "equity return")	$ 2,104,655	42.7%	(62,396)	$160,935	204,580	78.67%	calc'd on ratios

Rev. Req. Model
Inputs in yellow
Figures Based on UE-88 (Order 95-322)

	At Current Rates	Additional Rev for 11.6% ROE	Proposed
1 Sales to Consumers	886,103	47,162	933,265
2 Sales for Resale	-		-
3 Other Revenues	10,795		10,795
4 Total Operating Revenues	896,898	47,162	944,060
5 Net Variable Power Costs	306,799		306,799
6 Fixed Power Costs	71,532		71,532
7 Other O&M	134,640	1,193	135,833
8 Total Operating & Maintenance	512,971	1,193	514,164
9 Depreciation/Amort	146,882		146,882
10 Taxes Other Than Income	48,579		48,579
11 Utility Income Tax	61,958	18,121	80,079
12 Total Operating Expenses & Taxes	770,390	19,314	789,704
13 **Utility Operating Income**	126,508	27,848	154,356
14 **Average Rate Base**			
15 Rate Base	1,585,834		1,585,834
16 Working Cash	36,726	879	37,605
17 **Average Rate Base**	1,622,560	879	1,623,439
18 **Rate of Return**	7.80%		9.51%
19 **Implied Return on Equity**	7.83%		11.60%
20 Effective Cost of Debt	7.710%	7.710%	7.710%
21 Effective Cost of Preferred	8.270%	8.270%	8.270%
22 Debt Share of Cap Structure	49.14%	49.14%	49.14%
23 Preferred Share of Cap Structure	5.42%	5.42%	5.42%
24 Weighted Cost of Debt	3.789%	3.789%	3.789%
25 Weighted Cost of Preferred	0.448%	0.448%	0.448%
26 Equity Share of Cap Structure	45.44%	45.44%	45.44%
27 State Tax Rate	6.672%	6.672%	6.672%
28 Federal Tax Rate	35.120%	35.120%	35.120%
29 Composite Tax Rate	39.449%	39.449%	39.449%
30 Bad Debt/FF/OPUC Rate	2.530%	2.530%	2.530%
31 Working Cash Factor	4.550%	4.550%	4.550%
32 Gross-Up Factor	1.651	1.651	1.651
33 ROE Target	11.60%	11.60%	11.600%
34 Grossed-Up COC	13.23%	13.23%	13.23%
Utility Income Taxes			
30 Book Revenues	896,898	47,162	944,060
31 Book Expenses	672,077	1,193	673,270
32 Interest Deduction	61,474	33	61,507
33 Deferred Ms	(28,219)	-	(28,219)
34 Book Taxable Income	191,566	45,936	237,502
35 State Taxes	12,781	3,065	15,846
36 State Tax Credits	(166)	-	(166)
37 Net State Taxes	12,615	3,065	15,680
38 Federal Taxable Income	178,951	42,871	221,822
39 Federal Taxes	62,848	15,056	77,904
40 ITC Amort	(1,985)	-	(1,985)
41 Deferred Taxes	(11,520)	-	(11,520)
42 Total Income Tax Expense	61,958	18,121	80,079

45,250.70	(1,911)
47,162.14	
49,073.67	1,912

Rate Base w/Trojan

RB	1,622,560
COE	19.16%
COD	7.710%
Cap Change	1%
Rev Req	1,857

Approx Rate Base w/o Trojan

RB	1,372,560	Trojan about $250 MM
COE	19.16%	
COD	7.710%	
Cap Change	1%	
Rev Req	1,571	

10% Change in Cap Structure (9 months):

Pre-Tax	11,784
After Tax	7,070

Table A

Test Year 1995

	Capital Structure	Cost	Weighted Cost
Long-Term Debt	49.14%	7.71%	3.79%
Preferred Stock	5.42%	8.27%	0.45%
Common Equity	45.44%	11.60%	5.27%
	100.00%		
Rate of Return			9.51%

Table B

Test Year 1996

	Capital Structure	Cost	Weighted Cost
Long-Term Debt	48.86%	7.82%	3.82%
Preferred Stock	4.67%	8.27%	0.39%
Common Equity	46.47%	11.60%	5.39%
	100.00%		
Rate of Return			9.60%

Table C

Test Year 1995

	Capital Structure	Cost	Weighted Cost
Long-Term Debt	49.14%	7.71%	3.79%
Preferred Stock	5.42%	8.27%	0.45%
Common Equity	45.44%	11.85%	5.38%
	100.00%		
Rate of Return			9.62%

Table D

Test Year 1995

	Capital Structure	Cost	Weighted Cost
Long-Term Debt	49.14%	7.71%	3.79%
Preferred Stock	5.42%	8.27%	0.45%
Common Equity	45.44%	13.10%	5.95%
	100.00%		
Rate of Return			10.19%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

The Regulatory Compact

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Jeff D. Makholm, Ph.D

February 15, 2005

I. Qualifications, Purpose, and Conclusions

Q. Please state your name, business address and current position.

A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with principal offices in a number of major U.S. and European cities. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116

Q. Please describe your academic background.

A. I have M.A. and Ph.D. degrees in economics from the University of Wisconsin, Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. I also have B.A. and M.A. degrees in economics from the University of Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q. Please describe your work experience.

A. My work centers on economic issues involving pricing, market definition, and the components of reasonable regulatory practices for regulated companies. Much of my international work focuses on regulatory design and structural issues, such as industry restructuring, privatization, and the introduction of incentive-based regulation. Issues of reasonable regulatory practices include the analysis and evaluation of alternative regulatory approaches, the creation of credible and sustainable accounting rules for ratemaking, and the establishment of administrative procedures for regulatory rulemaking and adjudication. I have prepared expert testimony and statements, and I have appeared as an expert witness in many state, federal and United States District Court proceedings, as well as in regulatory and judicial hearings abroad.

I have also directed studies on behalf of utility companies, governments and the World Bank in many countries on economic and regulatory issues, such as the specific issues of competition, rate design, fair rate of return, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy, and reasonable regulatory practices. In these countries, I have consulted on regulations, tariffs, recommended financing options for major capital projects and advised on industry restructurings. I have also assisted in the privatization of state-owned gas utilities. As part of my international work pertaining to the gas industry, I have conducted formal training sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Regarding rate of return and utility financing questions specifically, I have testified for electric, natural gas, water and telecommunications utility clients before state commissions in Pennsylvania, Oregon, Ohio, North Carolina, Kansas, New Jersey, New York, Maryland, California, Virginia, Rhode Island, New Hampshire, Texas, Indiana, Maine, Wisconsin, Illinois and Connecticut, as well as before the Federal Energy Regulatory Commission (FERC). My current curriculum vitae, which more fully details my educational and consulting experience, is provided as PGE Exhibit 6501.

Q. What is the purpose of your testimony?

A. I explain the nature of the "regulatory compact," which is investors' expected basis for economic regulation of utilities in the United States. I also review the consequences of one interpretation of Oregon law wherein Oregon utilities retiring assets with an undepreciated balance can receive only a return of those assets in limited amount over an extended period of time with no return on the undepreciated capital balance.

Q. What conclusions have you drawn?

A. I conclude that investors will demand a larger return for Oregon utility investments because of this anomaly from the expected regulatory compact arising from this particular interpretation of Oregon law.

Q. How is your testimony organized?

A. This testimony is organized as follows. In Section II, I explain the economic underpinnings of economic regulation as commonly understood throughout the United States. This Section begins by explaining the fundamental economics of investor-owned utility companies, moves to the regulatory compact and then on to the "capital attraction" function—the key function—of just and reasonable utility rates.

Section III shows how the regulatory compact has generally accommodated other power plants—assets that are highly capital intensive, take years to build, and are sometimes retired before their originally projected useful lives, as in the case of the Trojan plant.

Section IV discusses the implications of the regulatory compact and its applications for Trojan. In this section, I also review how the regulator in Oregon upheld the regulatory compact when reviewing the actions of PGE with respect to Trojan.

II. The Uniqueness of Public Utilities and the Regulatory Compact in the United States

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

A. This section describes the particular qualities of investor-owned public utilities that have led, in the interest of consumers, to the regulatory compact. The regulatory compact has shaped investor expectations in the United States for decades regarding the risk of investing in public utility infrastructure, like power plants.

Q. Can you outline how you discuss this issue of the regulatory compact?

A. Yes. My discussion supports the following well-accepted characteristics of public utilities and regulatory institutions in the United States:

- Utilities are not your normal business—they are directly connected to their public users in particular locations with unusually capital-intensive facilities.
- Regulation has developed over its history, particularly in the U.S., to serve two goals: (1) to maintain essential services to the public; and (2) to limit prices for those services to what is considered fair—that is, limited to the reasonable costs of the companies providing that service.
- The need to balance the competing interests of the public and the investor-owners of public utilities has resulted over time in the regulatory compact in the U.S., which has been the staple of U.S. regulation—as confirmed by the courts.
- Ultimately, it is customers who benefit from the regulatory compact, as it allows investor-owned utilities to anticipate a consistency of regulatory control necessary to attract capital at lower prices than their unregulated industrial counterparts.

In discussing these concepts, this section will provide the groundwork for the discussion in Section III (regarding how the regulatory compact has been confirmed for utility investors for nuclear power plants closures in other jurisdiction), and Section IV (regarding the consequences to Oregon utilities and customers if a particular interpretation of Oregon law prevents the regulatory compact from working in the same way there).

A. Public Utilities Require Consistent Economic Regulation

Q. What do you mean by "regulator" or "regulatory bodies" in this discussion?

A. I mean more than just a state or federal regulatory agency or commission. I mean the entire framework of economic regulation for a public utility, including the laws and policies adopted by legislative bodies and in Oregon's case, by state initiative. The laws and policies of the legislature guide and in some cases severely limit what an agency or commission can do. In other words, the "regulator" is the agency or commission working within the policies and laws of the legislature.

Q. What is unique about public utilities?

A. Public utilities are unique in that they serve the public—and indeed are physically connected to the customers they serve—with extensive and expensive facilities whose only purpose is to provide reliable services (like electricity, gas, water and telecommunication) to their customers. They have obligations that normal industrial firms do not. That is, they must provide uninterrupted service to all comers and also have a greater need to plan and invest to make sure that those services continue.

In addition, they are typically local monopolies, reflecting the widely held—and essentially correct—conviction that the duplication of such services, with competing electric wires or gas pipelines for example, would be inefficient and wasteful. Their local monopoly status requires that the same regulators that compel them to provide uninterrupted and high quality services also must regulate pricing to limit their charges to what is considered cost based and reasonable.

Q. Are public utilities in the U.S. generally owned by investors?

A. Yes. From the growth of public utility industries in the U.S. in the 19^{th} century, investor ownership has dominated the industry. There are many localities—and some broader jurisdictions—that provide utility services by governmental authorities, but they are in the minority in the U.S. The normal model in the U.S. is for investor-owned firms like PGE to provide public utility services.

Q. Is consistency and predictability of regulation important for investor-owned utilities like PGE?

A. Yes. The public would not be well served—either in the quality of services they receive or in the prices for those services—without consistency and predictability in regulation.

Q. Why is that?

A. It is because the long-lived nature of utilities' investments requires a long-term assurance of payments from utility customers in order to give investors confidence that their investments ultimately will be recouped.

Investor-owned public utilities are highly capital intensive—more so than industrial firms generally. In addition, the capital assets that utilities employ to serve the public are highly specialized and cannot generally be redeployed to alternative uses or locations—which is to say, the local wires of electric utilities or pipelines of a gas utility have little value if they're not used where they are. As such, the industry is highly exposed to expropriation of its capital investments if inconsistent regulation would prevent it from recouping the costs of its investments over the long lives of those investments.

Capital investments, however, are not simply done once and forgotten. The continuing need for new customers to be served, and for old capital to be replaced to maintain existing services, necessitates an ongoing flow of dollars into new capital assets. As such, utilities must have uninterrupted access to capital markets to maintain and upgrade capital facilities to serve existing and new customers – all of whom they are compelled to serve by their public utility service obligations.

Q. Please describe these "capital markets."

A. These are markets where utilities go to sell shares to raise stockholder equity, or where they sell bonds to borrow money. The prices that investors and lenders require in the capital markets are unregulated. These markets are very large in relation to the size of any individual utility, which in the terminology of economics makes utilities "price-takers." That is to say, when utilities go to the capital markets to raise equity funds or borrow money through the issuance of bonds, they pay the going competitive rate that investors require for companies of their type and perceived level of risk.

As price takers, utilities can only attract capital at reasonable rates by showing that investors' capital is reasonably safe from loss and will be repaid with a market-based rate of return through a transparent system of regulated prices. Because of the potential exposure of utility investments to expropriation, economic regulation for such utilities must be highly credible in the eyes of the investors. Without such regulatory credibility, utilities cannot attract private investment—jeopardizing the provision of essential public services.

Q. Is such regulation to which you refer a long-standing institution?

A. Yes—it is quite long-standing. The economic regulation, in some form, of businesses that serve the public is a fundamental part of the common law. As early as the 17th century, Lord Chief Justice Hale (in his treatise *De Portibus Maris*) recognized that "...the wharf and crane and other conveniences are affected with a public interest and they cease to be *juris* *privati* only."[1] All economic regulation of businesses (then and now) proceeds from the premise that citizens deserve adequate services at reasonable prices, but also that regulated businesses deserve a compensatory—that is to say reasonable—rate for the services they provide.

There are two basic duties of regulation that stem from this history. The first duty of regulators is to ensure that companies that supply the public do so safely and adequately. The second is to ensure that the prices paid by consumers are just and reasonable, based on prudently-incurred costs. Part of this second duty of regulators is to ensure that their actions and decisions do not diminish the property rights of those companies who provide the regulated services to the public. This latter duty is both a legal and a practical one. That is, without an assurance that regulators will not seize the property of regulated companies, the company cannot maintain sufficient financial integrity to be able to engage in the ongoing capital commitments necessary to provide uninterrupted service at a reasonable price

B. The Regulatory Compact

Q. What does the available literature say about regulation of investor-owned public utilities?

A. The literature on regulation of investor-owned public utilities refers consistently to the concept of the regulatory compact, defined, as follows:

> First, in return for a monopoly franchise, utilities accept an obligation to serve all comers. Second, in return for agreeing to commit capital to the

[1] See: Phillips, Charles F. Jr., *The Regulation of Public Utilities*, Public Utilities Reports, 1993, page 91, ("Phillips").

> business, utilities are assured a fair opportunity to earn a reasonable return on that capital.[2]

In mature regulatory jurisdictions with an extensive legal and administrative history, such as the U.S., the regulatory compact represents a combination of Constitutional rights, federal and state statutes, franchise agreements, regulatory commission rules, policy statements, and so on.

The regulatory compact is supported in the U.S., in particular, by a considerable history of: (1) strong primary legislation; (2) credible, comprehensive and transparent administrative procedures for making regulatory decisions and adjudicating disputes; (3) accounting regulation specifically designed for utility rate making; and (4) clear pathways for reliable judicial review of regulatory decisions. Newer regulatory jurisdictions around the world that do not have comparable bodies of regulatory precedent routinely use explicit contracts to express such principles.

These principles are generally true of all utilities regulated in the U.S. Both equity investors and lenders generally devote funds to U.S. utilities with the expectation that these principles of the regulatory compact will be honored. Even though the particular utility statutes may vary from state to state, and even though regulatory commissions may have different policies and precedent in different states, investors anticipate the regulatory compact will apply to their investments. For this reason my analysis does not depend on any particular state utility statutory scheme.

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[2]Stelzer, I.M., *The Utilities of the 1990s*. The Wall Street Journal, January 7, 1987, 20, as referenced in Phillips, C.M., *The Regulation of Public Utilities, Theory and Practice*, Public Utilities Reports, Inc. Arlinton, Virginia (1993), Pg. 21.

C. The "Capital Attraction" Function of Regulated Prices

Q. What is the key requirement for the success of regulation of investor-owned utilities?

A. The key requirement for the success of the regulation of any investor-owned utility is to assure that the company in question maintains its financial integrity so as to be able to continue to fund its operations and serve the public.

1. Attracting Capital in the Market

Q. What role does attracting capital play in the regulated prices charged by investor owned utilities?

A. Capital attraction determines the basic constraint that investor ownership places on the level of regulated charges. Professor James C. Bonbright, a widely referenced expert on the principles of public utility prices, describes what he called the "capital attraction function" for investor-owned public 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. [3]

Professor Roger Morin echoes the importance of capital attraction more recently:

> It must be understood that both capital attraction and financial integrity standards must be fulfilled in determining a fair rate of return. Despite a deterioration in credit standing, a utility may be able to attract capital temporarily, but at prohibitive costs and under unfavorable terms. Eventually, the utility will face hard funds rationing and/or the costs of

[3] Bonbright, J.C., *Principles of Public Utility Rates*, Columbia University Press, New York (1961), pp. 49-50.

> financing will become prohibitive, and the utility can not longer attract capital at a reasonable price.[4]

Further, Professor Bonbright states that the capital attraction function for utility ratemaking has always been a key concern for regulators as well as regulated companies.

> ... In public utility cases in which the general *level* of rates (as distinct from the rate *structure)* is at issue, the capital-attraction standards of reasonable rates tends to be accepted by [regulatory] commissions as the primary basis for their decisions. Even the representatives of the public utility companies will usually base their requests for a rate increase or their opposition to a rate decrease on the ground of a need for credit-sustaining revenue.

Q. How does return on investment affect attracting capital in the capital markets?

A. Given the high operating leverage for public utilities (*i.e.*, the use of a high proportion of fixed investment costs relative to variable costs), the ability of regulated utilities to reliably provide a return to their owners is essential to obtaining credit ratings that facilitate the acquisition of capital. Independent credit ratings agencies, such as *Standard & Poor's* (*S&P*), provide comprehensive discussions of the factors that lead them to grant "investment grade" ratings for investor-owned electric utilities.[5] Consistent regulatory treatment is key to *S&P's* ratings:

> Regulation defines the environment in which a utility operates and has great influence on the company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy as a result of a supportive regulatory environment. Conversely, *unpredictable or antagonistic regulatory action can*

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[4] Morin, R.A., *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports, Inc., Arlington, Virginia (1994), pg. 12.

[5] Standard and Poor's defines "investment grade" as follows (See: Standard & Poor's Corporate Ratings Criteria, Update to the 1994 edition, p. 12): The term "investment grade" was originally used by various regulatory bodies to connote obligations eligible for investment by institutions such as banks, insurance companies, and savings and loan associations. Over time, this term gained widespread usage throughout the investment community, Issues rated in the four highest categories. "AAA", "AA", "A", "BBB", generally are recognized as being investment grade. Debt rated "BB" or below generally is referred to as speculative grade. The term "junk bond" is merely a more irreverent expression for this category of more risky debt.

> *undermine the financial position of utilities that are very strong from an operational standpoint.* To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory polices and the length of time that the regulatory framework has been in place.[6] (Emphasis added)

In addition, *S&P* states that,

> Standard & Poor's evaluation of regulation also encompasses the administrative, judicial, and legislative processes involved in local or national regulation. These can affect rate-setting activities and other aspects of the business, such as competitive entry, environmental and safety rules, facility siting, and securities sales... Standard & Poor's ratings factor in the impact of such constraints and obligations on a utility's operations and financial performance.[7]

S&P speaks credibly on behalf of the capital markets, and these statements underscore the key role of capital attraction in setting fair and reasonable tariffs.

Q. What is the amount of capital construction by investor-owned utilities in the U.S.?

A. The amount of capital investment by investor-owned utilities from 2000 to 2004 in the U.S. was $195 billion.[8] Such a figure illustrates the magnitude of the financial needs to support the utility infrastructure in the U.S. and the importance of the regulatory compact in supporting such investments.

2. Legal Supports for the Regulatory Compact: "*Bluefield*" and "*Hope*"

Q. What legal precedent exists for investor owned utilities ability to attract capital?

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[6] Cheryl E. Richer, "Rating Methodology for Global Power Utilities," Standard & Poor's Infrastructure Finance, September 1998, p. 65.

[7] *Id.*, p. 66.

[8] "2003 Financial Review Plus 2004 Developments: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry," (Washington, D.C.: *Edison Electric Institute*, 2003), p. 27.

A. The United States Supreme Court established the traditional standard for a fair and reasonable return in its *Hope* decision (*Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)):

> ...the return to the equity owner should be *commensurate with returns on investments in other enterprises having corresponding risks.* That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to *maintain its credit and attract capital.* (Emphasis added.)

This often-quoted passage from the *Hope* decision, besides providing a legal standard for determining the fair rate of return, comports precisely with the opportunity cost standard for determining the fair rate of return that covers the utility's cost of capital.

In an earlier case, *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679, 693 (1923), the Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.

Finally, the Supreme Court stated in *Bluefield* that establishing an insufficient return on invested capital denies shareholders the Constitutional right of due process under the Fourteenth Amendment.

> Rates, which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being so used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment.

These two Supreme Court decisions in the U.S. have defined expectations for investments in U.S. public utilities to this day—indeed, they are generally referenced as the basis for determining the fair return to utility investors in modern rate cases.

3. Capital Attraction Is Not an "Academic" Exercise: PGE Spent $180 Million per Year on Capital Expenditures During the mid- to late- 1990s

Q. Would violating the regulatory compact harm ratepayers?

A. Yes. The regulatory compact exists to allow utilities to attract capital economically by giving investors the assurance that as long as the utility acts prudently and serves the public well, their investments will be repaid. As such, a violation of the regulatory compact would harm customers either by driving up the utility's costs of securing investment funds or, ultimately, in driving away investors and preventing utilities from having the ability to render uninterrupted service.

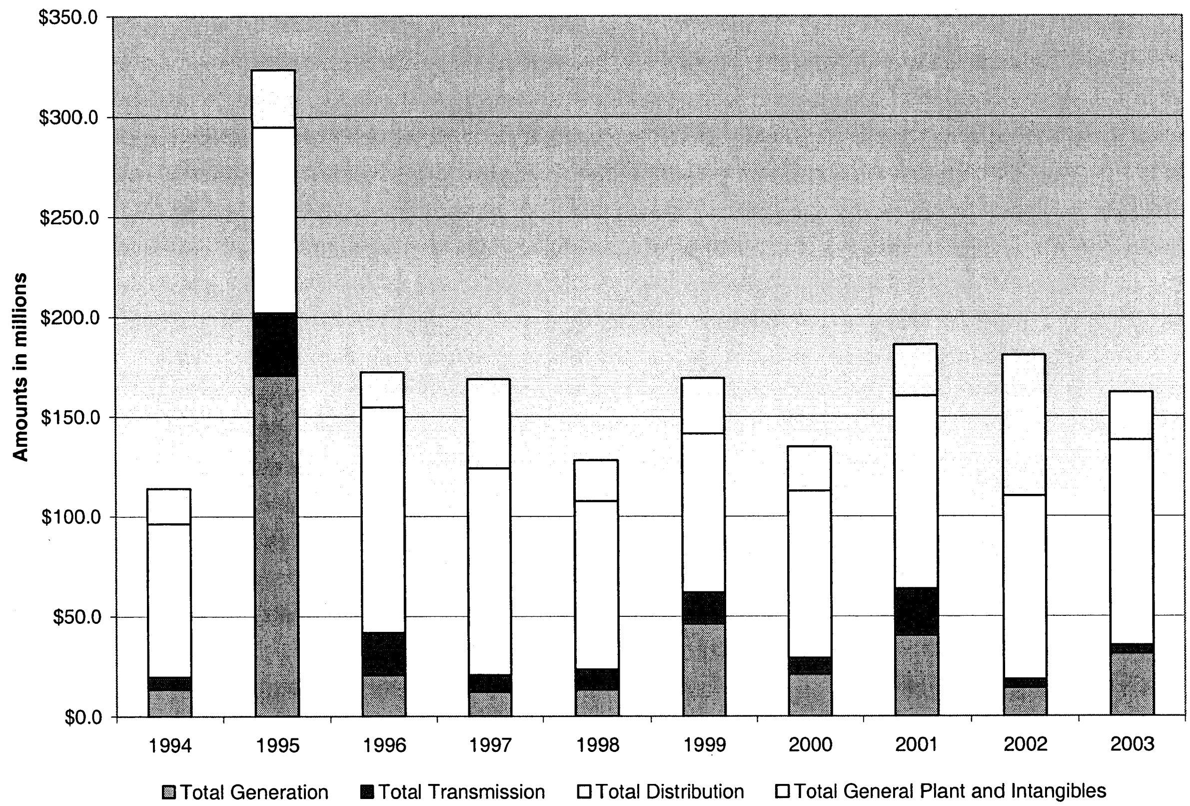
Q. Is this a relevant question for PGE?

A. Yes. PGE requires investment funds to pay for capital expenditures in new power plants, transmission and distribution lines, and the replacement/renewal of existing systems. This ongoing capital expenditure is required for PGE to continue to provide safe, adequate and reliable service for its customers.

Q. What capital expenditures has PGE faced in recent years?

A. PGE's capital expenditures include generation, distribution, transmission, and general plant and intangible plant expenses. From 1994 to 2003, the vast majority of PGE's utility plant capital expenditures, 82.8 percent, were spent on upgrading or replacing generation, distribution, and transmission facilities that directly impacts the consumer of electricity. The remainder of the capital expenditures was spent to purchase land, structures, office

Figure 1: PGE's Capital Expenditures by Segment (1994-2003)[9]



supplies, communication equipment, and other tools needed to run the utility. Figure 1 details the capital expenditures for PGE from 1994 to 2003.

Q. What financings did PGE undertake during this period?

A. PGE has been active in financing activity from 1994 to 2003, as shown in Figure 2.

[9] Source: FERC Form 1 for PGE 1994-2003.

Figure 2: PGE's Financing Activity by Segment (1994-2003)

Portland General Electric
Financing Activity (in millions) [1]
1994-2003

Year	Capital Expenditures for Utility Plant	Total Capital Expenditures [2]	Total New Financing [3]
1994	$114.0	$221.7	$126.6
1995	$323.4	$211.8	$176.3
1996	$172.4	$186.9	$170.6
1997	$168.8	$188.0	$12.2
1998	$128.1	$165.9	$147.1
1999	$169.2	$226.3	$160.9
2000	$134.9	$182.2	$147.3
2001	$186.0	$211.9	$308.4
2002	$180.7	$180.3	$250.0
2003	$162.1	$187.2	$334.5
1994-2003 Average	$174.0	$196.2	$183.4

[1] Financial Data is from FERC Form 1s.

[2] Total Capital Expenditures includes capital expenditures for utility and non-utility plant, Trojan decommissioning expenses, sales of assets, and +/- change in construction work in progress.

[3] Total New Financing includes new long term debt, short term debt, equity, and other financing.

Q. Are good credit ratings important to PGE's ability to support such investments?

A. Yes. With respect to the importance of maintaining credit ratings, PGE states that, "credit ratings reduction would likely have an adverse effect on the Company's ability to issue commercial paper and increase the cost of funding its day-to-day working capital requirements."[10] Without viable and sustained access to the capital markets, PGE's ability to invest in utility generation, transmission, and distribution plant might have been

[10] 2001 SEC Form 10-K for Portland General Electric Co., p. 35.

compromised. At the very least, costs for obtaining those funds for its public service investments would have been considerably greater.

Q. What do you conclude about the role of the regulatory compact?

A. The regulatory compact developed in the U.S.to assure that utility customers would be reliably served by highly capital intensive utilities at the lowest reasonable cost, and that PGE and its customers have continuing needs to attract capital at the lowest reasonable cost. The following two sections of my testimony take the regulatory compact as a point of departure to discuss the following:

1. Section III discusses how that compact has served to confirm utility investors' expectations regarding the safety of prudent utility investments in other states—even when nuclear power plants like Trojan were retired before the end of their projected lives.

2. Section IV discusses how an abandonment of the regulatory compact in Oregon—through one interpretation of Oregon law—would separate the State in the minds of investors from the rest of the U.S. and drive up investment risk and costs to serve Oregon ratepayers.

III. Nuclear Power Plant Construction, Operation and Retirement in Other Jurisdictions

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

A. This section shows how the regulatory compact responds to assets that are highly capital intensive, take years to build, and are sometimes retired before the end of their projected useful lives. I present examples from other jurisdictions to illustrate the general consistency of treatment of nuclear power plant costs—expectations that were present in Oregon when Trojan was built and when the decision came to close it.

A. The Regulatory Compact and Findings of Imprudence

Q. What is the role of "imprudence" in the regulatory compact?

A. The regulatory compact is a two-way street—reciprocal obligations on both investor-owned utilities and regulators. If the utility does not serve all ratepayers with safe, adequate and reliable service at the lowest reasonable cost, then a regulator may have cause for a disallowance of all or part of an investment based on a finding of "imprudence." These findings are specific to particular expenditures and circumstances.

Q. How do regulators evaluate the prudence of decisions and actions by utilities relating to their generation assets.

A. From initial planning and development to operation and maintenance—and ultimately retirement and decommissioning—regulators evaluate prudence in virtually all the activities relating to generation assets.

The process begins at the planning stage. Before a project is developed, utilities must obtain approvals from local, state and federal agencies. Once the project is developed the regulator also evaluates the costs of the project the next time the owner is involved in a rate case. At this point, the regulator determines which costs relating to the project can be recovered and/or added to the "rate base" so that a return on capital can be collected from ratepayers over the life of the plant.

Once a plant is placed into service and its costs are approved and added to the rate base, the regulator has explicitly endorsed the investment as a prudent investment. From that moment, future actions relating to operation, maintenance and management of the project can also be scrutinized in additional rate reviews and audits by state and federal agencies.

Finally, regulators can express their approval or disapproval of the decision to retire or continue operating plants. Utilities can conduct specific studies that provide analysis to inform these decisions, or they can include this analysis in an Integrated Resource Plan (IRP), which is a comprehensive evaluation of the least cost way of meeting future energy demand. As we discuss later in this section, an IRP conducted by PGE and reviewed by the regulators demonstrated that the expected benefit of continuing to operate Trojan to be negative (or stated differently, there was a positive customer benefit to close Trojan.) The regulator used this study to determine that early closure of Trojan was prudent.

B. How the Regulatory Compact Has Been Applied in Cases Involving the Early Retirement of Nuclear Plants

Q. Have regulators in other jurisdictions been clear about whether early retirement of nuclear plants justified a disallowance?

A. Yes. In other jurisdictions, regulators have been clear that disallowances should be applied only when there is imprudence and not simply because a plant was retired early for prudent economic reasons. The following enumerates cases where nuclear plants were retired early and describes how regulators dealt with the recovery of and on the unamortized portions of those plants.

1. Connecticut Yankee

Based on a 1996 Continued Unit Operation study, which concluded that under several different scenarios replacement power costs were less than the costs of continuing to operate the plant, the owner-purchasers of Connecticut Yankee Atomic Power Company (Connecticut Yankee) voted unanimously to retire the plant. Several other interested parties, including the Connecticut Office of Consumer Counsel (COCC), contested Connecticut Yankee's decision before the Federal Energy Regulatory Commission.

In its Opinion and Order Affirming the Initial Decision, the FERC stressed the implications of the regulatory compact as stated in the Initial Decision. The FERC explained that the ALJ in his Initial Decision found that Connecticut Yankee management of the plant was imprudent. But as an alternative, in case the FERC did not agree with his finding of imprudence, the ALJ recommended a return on and a return of the undepreciated balance in Connecticut Yankee:

> In the event that the Commission did find that Connecticut Yankee had acted prudently and was thus entitled to a return on equity, the judge adopted the trial staff's proposed return on equity of 8.63 percent to reflect that Connecticut Yankee's risks had been reduced following shutdown.[11]

Between the Initial Decision and the FERC ruling, Connecticut Yankee settled for full recovery of the unamortized portion of its nuclear plant at a lower rate of return.[12] In the Opinion and Order Affirming the Initial Decision, the remaining issue confronting the FERC was the COCC's interpretation of language in amendments to the basic contracts to

[11] Connecticut Yankee Atomic Power Co., Docket ER97-913-000, Opinion 449, 92 FERC ¶ 61,269 at 61,898 .(Sept. 28, 2000)

[12] Id at 61,899.

purchase power from the plant. COCC claimed the amendments disallowed Connecticut Yankee from collecting all costs other than decommissioning costs. The judge and the FERC both agreed that the proper standard for evaluating the contract provisions was the just and reasonable standard. Regarding the amendments the Commission stated that:

> We affirm the judge's finding that the proper standard for evaluating the proposed amendments contained in the 1996 Agreements between Connecticut Yankee and each of its ten purchasers is the just and reasonable standard. No exceptions were taken to this finding.[13]

And,

> Although the judge acknowledged the deleted language "is understandably susceptible to the construction suggested by the interveners," we find that the judge properly determined, on the basis of other provisions in the contracts, that this language was not intended to relieve owner-purchasers of other legitimate obligations that remain to be paid after the shutdown.[14]

Thus, the judge and Commission both affirmed that the basic logic and value of the regulatory compact should supersede when possible interpretations go against the economic principles that are essential to this compact.

2. Maine Yankee

In a similar case to Connecticut Yankee, the Maine Yankee nuclear plant was shut down for economic reasons in 1997. The nuclear facility faced increasing operation and maintenance expenses as well as looming capital expenditures to keep the plant operating. It was disputed that imprudence was a factor for the early retirement of the plant.[15] Given that it was arguable that economic reasons (beyond Maine Yankees' control) and some imprudent management both contributed to the early retirement of Maine Yankee, a

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[13] Id at 61,901.

[14] Id.

[15] Before the FERC, Maine Yankee Atomic Power Co. Docket ER98-570-000, "Commission Trial Staff's Comments In Support of Offer of Settlement," Filed January 19, 1999, p. 6.

settlement was reached that involved a lower rate of return than the one originally requested by Maine Yankee. [16] The full undepreciated investment in Main Yankee was recovered at this rate of return. Thus, Maine Yankee provides another example where the early retirement of a nuclear plant was evaluated to carefully discern between economic reasons beyond the control of the plant owner and varying degrees of imprudence.

3. Millstone 1 – WMECO (Massachusetts)

Another nuclear plant that was shut down early in part for economic reasons was Millstone 1, primarily owned by Western Massachusetts Electric Company. Similar to the Connecticut Yankee case, it was also claimed that reasons relating to imprudence played a role in the early retirement of Millstone 1.[17] The consideration of the regulatory treatment for Millstone 1 was complicated by the need to analyze the plant shutdown under the recently enacted Massachusetts restructuring law. However, both the Massachusetts Attorney General and the Massachusetts Department of Telecommunications and Energy (MDTE) were careful to explain that, under the new law, shutting down the plant early solely for economic reasons was in the public's interest and thus would not have created justification for any disallowance. This explanation was first provided by the Massachusetts Attorney General and later cited by the MDTE. In an order issued by the MDTE, it recalled the following:

[16] This settlement was uncontested. 87 FERC ¶ 61,252 (June 1, 1999)

[17] Massachusetts Department of Telecommunications and Energy, Order for Docket D.T.E. 97-120; Re: "Petition of Western Massachusetts Electric Company pursuant to General Laws Chapter 164, Sections 76, 94 and 220 C.M.R et. seq., for review of its electric industry restructuring proposal." p. 23.

> The Attorney General contends that in order for a company to be entitled to a full stranded cost recovery, it must have demonstrated that its generation–related assets became uneconomic due to competition.[18]

In that same Order, the MDTE states that:

> In order to allow transition cost recovery, the Department must determine whether the Company's decision to retire the plant was based upon an analysis that the plant was uneconomic due to the creation of a competitive generation market.[19]

Ultimately, the MDTE determined that the plant had been shut down in part due to imprudent actions. Nonetheless, the standard set by the Massachusetts regulators in the Millstone case provides another example where the decision to allow recovery, including a return on the unamortized portion of the plant, was based on whether the plant was shut down solely for economic reasons and not for reasons of imprudence.

[18] Massachusetts Department of Telecommunications and Energy, Order for Docket D.T.E. 97-120; Re: "Petition of Western Massachusetts Electric Company pursuant to General Laws Chapter 164, Sections 76, 94 and 220 C.M.R et. seq., for review of its electric industry restructuring proposal." p. 23.

[19] Massachusetts Department of Telecommunications and Energy, Order for Docket D.T.E. 97-120; Re: "Petition of Western Massachusetts Electric Company pursuant to General Laws Chapter 164, Sections 76, 94 and 220 C.M.R et. seq., for review of its electric industry restructuring proposal." p. 25.

IV. The Case For Trojan: Implications Of The Regulatory Compact

Q. What are the basic implications of the regulatory compact and its applications with respect to Trojan?

A. In Section II, I explained that the regulatory compact is more than a set of principles, it is essential to the solvency of regulated businesses like PGE. This is because PGE and other electric utilities are capital intensive. Without access to low cost capital, companies cannot remain solvent. However, without a sound and credible regulatory compact, lenders and investors are not willing to offer their capital at a low cost.

Section III demonstrates how important the regulatory compact is perceived in other jurisdictions. Dealing with all the unexpected costs, including the stranded costs associated with nuclear assets has been difficult for the industry and has tested the viability, credibility and rigor of the regulatory compact. Notwithstanding this challenge, regulators have generally approached each case with deliberate review processes and consistent actions based on sound regulatory principles.

The examples in Section III demonstrate the ability and willingness of regulators in other jurisdictions to discern between costs relating to the imprudence of management versus costs resulting from events that management cannot reasonably control. The examples also clearly illustrate that events leading to the early retirement of nuclear plants can result from either or both of these reasons. Regulators examine each case based on its individual characteristics and apply resolutions that are just and reasonable. Regulators do not excuse ratepayers from legitimate obligations simply due to a single case where the legal language is susceptible to that interpretation. Rather, it is the spirit of what is just and reasonable that guides the decisions of judges and Commissions in these situations. The case of Connecticut Yankee made that clear.

Given these principles and their application in other jurisdictions, the implications for Trojan are that investors had a clear expectation, consistent with regulatory principles in the U.S.generally, that they would be entitled to the recovery of the prudent costs relating to Trojan. If PGE did its part in cooperating with the regulator as required under the regulatory compact, then there is no economic basis to reverse decisions made by the regulator at the expense of PGE and it shareholders. Moreover, such actions could also harm ratepayers.

Q. Did PGE's Oregon regulators uphold the regulatory compact in its decisions related to the closure of Trojan?

A. Yes. A review of the interactions between PGE and its regulator reveals that the regulatory compact did function well and PGE did cooperate with the regulator. The regulator in Oregon had sufficient opportunity to judge the prudence of PGE with respect to Trojan and when it found imprudence, the regulator responded with appropriate actions. I summarize this process in the remainder of this section of my testimony.

Q. How did the regulators in Oregon make determinations regarding the prudence of costs incurred due to Trojan at all these possible stages, including planning, development, start-up operation and retirement?

A. In Oregon as in other states, a thorough regulatory process such as the one described above is used to determine the prudence of actions relating to large power plants such as the Trojan facility.

According to Moody's, PGE began obtaining necessary authorizations to build Trojan as early as 1969.[20] By the time Trojan went into service in 1976, PGE had obtained all the necessary approvals required by the NRC and other state and federal agencies.

During the years Trojan was in service, its operation, maintenance and management were carefully scrutinized during several rate cases and by both state and federal agencies. Several orders and opinions regarding rate issues were issued by the Oregon Public Utility Commission (OPUC) while Trojan was in service.[21] These cases provide several examples of the regulator's opportunities to evaluate the prudence of actions taken by PGE in relation to Trojan.

In addition to the opportunities to examine PGE's prudence in rate cases, the regulator also had the opportunity to review PGE's overall supply plan as described in its IRP. PGE published its second IRP in 1992. This IRP was updated in early 1993. The updated IRP showed that the costs of continued operation of the Trojan plant exceeded its benefits to customers. The Commission agreed with PGE's assessment of Trojan and authorized its closure. Thus, the decision to close Trojan was also subject to regulatory review.

In OPUC Order 95-322 (Docket No. UE 88), the commission dealt specifically with the prudence of the undepreciated investment and other costs associated with the early retirement of Trojan. The OPUC had the opportunity to determine if there was any imprudence on PGE's part and did in fact require PGE equity investors to bear a portion of these costs. Specifically, the OPUC disallowed certain costs related to plugging and sleeving as well a spare reactor coolent pump. Thus, it is clear that the Oregon regulator

[20] Moody's Public Utility Manual, 1970, p. 503.

[21] These included Dockets UF 3796, UE 47, UE 48 and UE 79

was playing its role in discerning between imprudent costs and costs that resulted from events beyond PGE's control. This is precisely analogous to the actions of regulators in other jurisdictions, which I discussed previously in this section.

Q. Was PGE an exception in its decision to retire Trojan due to economic reasons?

A. No. The landscape for nuclear generation changed in the generation industry from the 1970s to the 1990s. During the 1970s, the U.S. as a whole desired to reduce its dependence on fossil fuels due to high prices and geo-political uncertainty. By the late 1980s, prices for fossil fuel sources decreased and the operation and maintenance costs for nuclear power were found to be higher than originally anticipated. The industry also introduced the use of Least Cost Planning, also called an "IRP." Although the original pursuit of nuclear power was prudent, and in the interest of ratepayers at the time, the economic conditions surrounding nuclear power changed. Like other owners of nuclear generation, PGE ultimately found that the costs of Trojan no longer warranted further investment to keep it operational.

Indeed, regulators throughout the country were encouraging utilities to retire nuclear plants due to rising costs resulting in part from additional costs imposed on nuclear plant owners in the wake of the Three-Mile Island incident. This encouragement involved incentives to retire plants early. For example, in the case of SONGS-1 in California, and Trojan, the U.S.Office of Technology Assessment states that:

> State regulators' treatment of capital recovery in early retirement decisions for SONGS-1 and Trojan plants were intended to "encourage their acquiescence. SONGS-1 was retired in 1993 after 26 years of operation under an agreement between the California Public Utilities Commission (CPUC) Division of Ratepayer Advocates (DRA) and the owners of the unit (Southern California Edison (SCE) and San Diego Gas and Electric Co.). The agreement provided the utilities full recovery of the remaining

> $460 million in capital costs over an accelerated 4-year period rather than the remaining 15 years in the licensed life.[22]

In Trojan's case, the utility specifically examined the value of Trojan in light of other supply alternatives available to PGE. The regulator reviewed and approved the early retirement.

Q. What do you believe were legitimate investor expectations with respect to Trojan?

A. Investors had a clear expectation, consistent with regulatory principles in the U.S. generally, that they would be entitled to the recovery of the prudent costs of construction and to recover prudent levels of operating and maintenance costs. Further, investors had a reasonable expectation that they would be entitled to recover any undepreciated capital costs, including a return on undepreciated balances, if the plant was closed prematurely for economic reasons. Investors were aware that they bore the risk of not recovering certain costs if the operation, maintenance, and capital investments related to Trojan were ruled imprudent.

Q Has the opportunity to recover prudently incurred costs in Oregon provided reasonable incentives for efficient investment in and operation of generation?

A. Yes. It has provided a well-understood set of expectations that allocated risk in a defined fashion and enabled investors to react accordingly. It has also provided an investment framework that is consistent with the nature of generating assets, consistent with the risk in committing capital to such large and market-specific investments as generation plants and has nurtured a competitive wholesale market. This regulatory framework has facilitated an investment in electric generation that is sufficient to provide adequate reliability and to

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[22] U.S. Congress, Office of Technology Assessment, *Aging Nuclear Power Plant: Managing Plant Life and Decommissioning, OTA-E-575* (Washington, DC: U.S. Government Printing Office, September 1993), pp. 84.

reduce the dependence of Oregon on fossil fuels as an electric generation fuel through the construction of nuclear generation facilities.

This framework has also encouraged the efficient operation of generation, including nuclear generation, by holding investor's responsible for the prudence of management actions with respect to the construction, operation, and maintenance of generating plants. The regulatory policies of the Commission have been well-articulated and knowable to investors and can be expected to have favorably influenced the cost of capital. As with any regulatory system, risks were shared between customers and investors. This sharing or balancing is an essential feature of regulation that helps reduce the cost of capital and helps avoid the high transaction costs that customers would incur to individually manage risk.

Q. Given that the regulatory review process functioned well with respect to Trojan, is it reasonable to suggest that investors should bear the risk relating to the fact that Trojan became uneconomic?

A. No. Trojan was developed, operated and eventually taken out of service based on prudence requirements and an IRP process, both of which were carefully reviewed by regulators. Ultimately, Trojan was shut down as a result of market and regulatory developments unforeseen at the time the investors and regulators implicitly entered into their regulatory compact with respect to the Trojan investment. Thus, given that PGE's prudence was carefully monitored at every step of the way, subjecting investors to the unforeseen risk that Trojan become uneconomic would significantly alter the terms of the regulatory compact.

V. One Interpretation Of Oregon Law

Q. You have said that an interpretation of Oregon law may well change investor expectations in Oregon going forward. Please explain.

A. PGE and the OPUC worked together to decide that it was in customers' best interests, given what was known at the time, to retire Trojan in 1992 before the end of its projected life. The process by which the Company and the OPUC did this was familiar to utility investors and regulators alike, reflecting early nuclear power plant closures in other states. For investors, the key part of those decisions was a commitment to allow investors to recoup the prudent investment in Trojan by allowing a return of their capital over time with a rate of return on the remaining balance to fairly reflect investors' opportunity cost of capital.

What was unexpected, by either the Company or the OPUC, was that an interpretation of Oregon law by the Oregon Court of Appeals would serve to uphold some parts of the deal to close Trojan (i.e. the return of the undepreciated balance) while rejecting another (*i.e.*, the return on the undepreciated balance to reflect investors opportunity cost of capital). It would be akin to an interpretation of Oregon law that required Oregon banks, from now on, to accept from homeowners only the principal balance on existing mortgages over the original life of the loans, without the associated interest on the remaining balances. That would be an unexpected shock to the banks—which made those loans under under the expecatation of the payment of both principal *and* interest—that would destroy much of the value of those mortgages. The interpretation here is similarly a shock to PGE and its investors that would destroy much of the value of the investment in Trojan.

If this interpretation required PGE to recover its Trojan investment, without a return, over an extended period of time, then it would cause PGE investors to experience both a very large loss of value and signal that the regulatory compact in Oregon does not work for them.

Q. Is this interpretation of Oregon law consistent with the regulatory compact or regulatory practices in other states in the U.S.?

A. No. If an Oregon utility's return of its undepreciated investment can only be returned over an extended period of time, Oregon law is consistent neither with the regulatory compact nor, in my experience or knowledge, with regulatory practices in other states. As confirmed by the examples that I gave in the previous section, investors can reasonably rely on the return of their prudent investments. To the extent that investors in Oregon face a risk that, despite the best practices and intentions of both they and the regulator, that large proportions of investments may not be recouped, Oregon will see two results: (1) it will confront a risk that investors would not face in other U.S. utility regulatory jurisdictions; and (2) decision-making regarding when to retire/replace will shift facilities toward preserving inefficient facilities rather than serving the economic interest of ratepayers.

Q. Please expand on your answer regarding this new risk faced in Oregon.

A. In my experience, having participated in regulatory cases and commented on regulatory practices in the U.S. (and in 20 other countries) over 24 years, the disallowance of prudently-invested capital in Trojan by such means—that is to say, as an after-the-fact surprise to both the utility and its regulator—looks like an expropriation of an investment inconsistent with the regulatory compact. I say expropriation to mean the taking of a large proportion of investors' funds despite the regulatory planning that culminated in the original rate order on closing the plant.

If upheld, such a move in Oregon would cause utility investors, and market analysts like *S&P*, to factor this unusual—and to my experience unprecedented—risk into the price for which they would make funds available in the future. Just like utility investors internationally take into account particular risks for investing in jurisdictions that do not have a long-lived and settled regulatory compact, such a new reality in Oregon would cause investors to require an Oregon-specific risk premium.

As I stated in Section II, utilities must attract capital to the public service from the market—they have no means to compel its provision. Subsequent to a decision that would prevent the recovery of prudent Trojan investments, the OPUC would have to abandon its practice of using financial data from other electric utilities around the country to gauge PGE's cost of capital—as investments in those other jurisdictions would not reflect Oregon-specific risks. The OPUC would also have to examine and rule on particular risk premiums for Oregon utility investments if its rulings were to be held consistent with the longstanding *Hope* and *Bluefield* standards for adequately compensating utilities for the use of investors' funds.

Q. Has the investment community expressed concern about the result of this case and its effect on the ability of PGE to raise capital funds at reasonable costs?

A. Yes. *S&P* has already indicated in a January 2005 report on PGE that the Trojan case could result in a change to PGE's credit rating. Specifically, *S&P* states:

> In 1993, PGE shut down the Trojan nuclear plant as part of its least cost planning process and the OPUC allowed PGE to collect a return on and a majority of its investment in the plant. Lawsuits have been filed seeking to require PGE to refund $260 million of funds collected that represent a return on its investment in Trojan. Proceedings are currently underway both at the Marion County Circuit Court (class action cases) and the OPUC (remand of previous rate cases). Given the uncertainty over the outcome and timing of the proceedings and the likely appeal process,

> Standard & Poor's treats the potential outcome of the lawsuit and rate proceedings as only a contingent liability at this point. Negative financial impact from these proceedings, if any, will be incorporated by Standard & Poor's when determining the appropriateness of PGE's ratings.[23]

Q. Please expand on your prior answer regarding the decision-making process.

A. The PUC participated in a measured decision-making process regarding the possible early retirement of Trojan, and ultimately agreed to its closure, because it concluded that ratepayers' best interests were served in the process. Vital to this decision-making process was a willing and collaborative interaction between PGE (which had the best information about the possible cost of continuing to run Trojan and the cost of replacing that plant's electricity) the OPUC and the other stakeholders. If the current interpretations of Oregon law can upset such careful planning, then both the Company and the OPUC would now be on notice that there are other factors—other than customers' interests—that must bear on plant-closure decisions. Indeed, if PGE and the OPUC had perceived that this interpretation was likely, it would have affected both the decision to close Trojan and/or the decision on the timing of the repayment of investors' capital.

Q. Regarding the risk premium in Oregon, did you measure the premium that would be required under the Court of Appeals interpretation of Oregon law?

A. No. Patrick Hager of PGE has performed such an analysis supported by Professors Blaydon and Hess.

[23] Standard & Poor's Report on PGE January 26th, 2005.

VI. Conclusions

Q. What is your conclusion?

A. Investors expect investments in U.S.utilities to be made under the regulatory compact. That is:

> First, in return for a monopoly franchise, utilities accept an obligation to serve all comers. Second, in return for agreeing to commit capital to the business, utilities are assured a fair opportunity to earn a reasonable return on that capital.[24]

If investors in Oregon utilities must only have their invested capital in early retired plants returned, without interest over a long time, investors will understand the regulatory compact is inapplicable in Oregon. As a result investors will demand a higher return on their Oregon utility investment to compensate them for the greater risk of utility investments in Oregon.

Q. Does this conclude your direct testimony?

A. Yes.

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[24] *Supra Note* 1.

List of Exhibits

PGE Exhibit	Description
6501	Witness Qualifications

JEFF D. MAKHOLM
Senior Vice President
National Economic Research Associates, Inc.
200 Clarendon Street
Boston, Massachusetts 02116
(617) 621-0444

Dr. Makholm concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries. These issues include the broad categories of pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive rate making, and the unbundling of prices and services. Issues of market definition include assessments of mergers, including the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies and Parliamentary panels abroad.

Dr. Makholm's clients in the United States include privately held utility corporation, public corporations and government agencies. Focusing mainly in the areas of gas and electric utilities, he has represented dozens of gas distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas producers. Dr. Makholm has also worked with many leading law firms engaged in natural gas and electricity issues.

Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal— many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

Dr. Makholm is Co-Chair of NERA's Energy Practice.

UE-88 REMAND / PGE EXHIBIT / 6600
BLAYDON

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Impact on Rate of Return

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Colin C. Blaydon, Ph.D

February 15, 2005

I. Introduction

Q. Please state your name, occupation and business address.

A. My name is Colin C. Blaydon. I am Dean Emeritus and the William and Josephine Buchanan Professor of Management at the Tuck School of Business. My business address is the Tuck School of Business, 100 Tuck Hall, Dartmouth College, Hanover, NH 03755. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. I have been asked by Portland General Electric Company (PGE) to opine on the reasonableness of PGE's proposed allowed rate of return on equity capital given a regulatory environment in which PGE cannot recover a return on any undepreciated investment balance of a plant that is retired early to achieve the least cost outcome for customers.

Q. Please summarize the conclusions you reach in your testimony.

A. I conclude that the Court of Appeals' interpretation, disallowing any return on the undepreciated balance of a utility plant that is retired for economic reasons, increases the required rate of return that investors demand for investing in the Oregon utilities. Given the uniqueness of this new regulatory regime in the U.S., investors are likely to view Oregon utilities as above average risks relative to other utilities elsewhere in the U.S. Based on my analysis, PGE's proposed return on equity (ROE) of 13.1%[1] is reasonable because it falls within the range of estimated ROEs for electric utilities with above average returns. Additionally, the new regulatory regime in Oregon is likely to hurt the debt ratings of Oregon utilities, increasing their cost of debt.

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[1] I consider only the ROE suggested by PGE corresponding to an amortization period of 17 years since this corresponds to a long-run rate of return.

Q. What methodology do you use in applying the financial models to develop an empirical estimate of the required rate of return for equity capital?

A. I evaluate PGE's risk relative to a broad set of 83 other regulated electric Investor Owned Utilities (IOUs) – the set of regulated IOUs employed in the Oregon Public Utility Commission (OPUC) staff analysis for UE-88. For this analysis I used data available in 1994. By conducting an empirical analysis of the cost of equity capital for this set of IOUs, I am able to establish a reliable range of reasonable cost of capital estimates for companies of diverse risk levels. In my analysis, I employ a number of versions of the Dividend Growth Model, a widely used method of empirical finance for determining the cost of equity capital. I perform the analysis using data from credible and well-established sources such as CRSP, Value Line, and Thomson Financial/I/B/E/S, as well as from company SEC form 10-Ks.

II. Analysis of Risk in the Regulated Electricity Industry

Q. What is the cost of capital?

A. The cost of capital is the return that investors require in order to provide their capital to a company. Because a company finances its operations with equity capital and debt capital, the cost of capital can be made up of a mix of equity and debt, where the mix is weighted by the relative amounts of each in the financial structure of the company. The expected return to both debt and equity investors must be sufficient to compensate those investors for the time value of money and the risks associated with the particular investment. Since people prefer to have a dollar today rather than receive a dollar at some time in the future, investors demand compensation for making investment dollars available today. This is known as the time value of money. Likewise, investors demand higher expected returns from companies associated with greater risk. The riskier the company is perceived to be, the greater the likelihood that future cash flows will be much different from what the investors expect today. Given this expectation, they demand compensation for future uncertainty in the present. Investors reduce, or discount, expected future cash flows in order to determine how much they are worth today. The fraction by which investors discount uncertain future cash flows to calculate their present value is known as the discount rate. The greater the risk, the higher the discount rate applied to the expected cash flows from the company. The cost of capital is equivalent to this discount rate – it is the required rate of return that will attract investors to the company.

Q. Can you explain the key sources of risk and how each affects the cost of capital?

A. Risk includes financial as well as market risk. Market risk refers to the fundamental underlying risk of a particular company. This risk arises from factors that affect the revenues and costs and, therefore, the profits of the enterprise. Businesses whose profits are more exposed to the booms and busts of the general economy have higher market risk than firms with less exposure. For example, the computer networking hardware industry likely has more market risk than the electric utility business. This is true no matter how particular companies in each industry are financed because the networking hardware business is more subject to large swings in revenues and profits due to the ebbs and flows of the economy. Electric utility revenues and profits, on the other hand, are much less dependent on the booms and busts of the economy. Variability in utility financial results depends more on such factors as regulatory decisions and the weather (which affects the overall level of electricity demand). Since these variables have little to do with the ups and downs of the economy, electric utilities have less market risk than the more cyclical networking hardware industry. Thus, an important step in determining an appropriate discount rate is estimating the fundamental market risk of the enterprise being valued.

Financial risk arises when companies take on financial obligations such as debt. While both debt holders and equity holders are exposed to business risk, they are affected differently by financial risk. Debt holders have the first claim on cash flows since interest on debt is paid before any dividends may be distributed to equity holders. Similarly, if the assets are liquidated, debt holders are paid first and equity holders receive the remaining funds, if any. As the share of debt increases in the company's capitalization (i.e., financial leverage increases), the returns to equity holders become more variable.

This increase in variability of returns to equity holders is best seen by way of an illustration. If a company performs poorly, absent debt, equity holders receive whatever cash flows the company generates. But if the company takes on debt, payments to debt holders may exhaust cash flows before equity holders receive any. Alternatively, if a company performs exceptionally well, equity holders receive higher returns because debt holders are only eligible for a fixed payment of interest and not a share of the profit. The increase in the variability of returns to equity that results from financial leverage is a source of risk for which equity investors demand compensation. Therefore, an increase in financial leverage will raise the cost of equity, other things being equal.

Q. What types of risk are investors concerned about and how do these relate to the cost of equity capital?

A. Investors are concerned with the total risk associated with a company. The total risk of a company comprises two kinds of risk, non-diversifiable risk, made up of the market and financial risk discussed above, and diversifiable risk:

Total Risk = Diversifiable Risk + Non-diversifiable Risk

Diversifiable risks are risks that are unique to a particular project or firm and that investors can eliminate by holding a diversified portfolio of investments; hence, investors are not compensated for bearing diversifiable risks. When valuing an investment opportunity, diversifiable risks are properly reflected in calculating expected future cash flows, not in the discount rate.[2] Non-diversifiable risk, taking the form of market and financial risk, is the risk that the value of an asset will change in response to changes in the overall market. The cost of equity capital properly will reflect only non-diversifiable risk.

Electric utilities face a wide variety of both diversifiable and non-diversifiable risks. Examples of diversifiable risks include factors such as: operating risks associated with possible technical problems with the plant equipment; demand fluctuations due to unexpected changes in the weather; and impacts on operations and costs resulting from labor strikes. Examples of non-diversifiable risks include factors such as: changes in fuel costs that are correlated with the economy, labor costs, interest rate risks, construction costs, and maintenance costs. All of these costs are correlated with the overall economy. For example, as the economy heats up, more jobs become available, the demand for labor increases and labor becomes more expensive as wage rates rise. Conversely, as the economy slows, fewer jobs are available, unemployment increases, and wage rates fall. The same factors affect the costs for materials and for equipment.

Some risk factors may have elements of both diversifiable and non-diversifiable risk. Importantly, to the extent any of the risk factors facing an electric utility are associated with fluctuations in the economy, these risk factors are non-diversifiable and would impact the required return on equity demanded by investors.

Q. Using these financial principles, what opinions do you have regarding the relative risks in the electricity industry?

[2] That is, given a 25% probability of a negative event such as a mechanical breakdown causing cash flows of zero, an investor would adjust the cash flows by a factor of 0.75 to get the expected value of the cash flows. The investor would then discount this adjusted, or expected, cash flow by the cost of equity.

A. In PGE Exhibit 6602, I show a security market line, which embodies the fundamental relationship between risk and return. As the risk of an asset increases, the return required by investors rises as well. For illustrative purposes, the exhibit ranks the relative risk of various assets by placing riskier assets further to the right on the x-axis. U.S. Treasury bills ("T-bills") are widely regarded as the safest investment available in the capital markets, and are commonly referred to as risk-free assets. The likelihood of the U.S. Government defaulting on these instruments is viewed as extremely low, and because of their short-term maturity (less than one year) they are less susceptible to the inflationary risks that are commonly associated with long-term government bonds. In addition, long-term government bonds also contain a "term premium" over T-bills. This term premium is the extra compensation investors demand for the risks associated with tying up their money over a longer time horizon. Corporate bonds are found to the right of U.S. Treasury bonds because shifting to corporate bonds subjects investors to additional market and default risk, adding to the required return necessary to attract capital. Investment in common stock (equity) carries the additional risks associated with the particular business and how its profits fluctuate with the overall economy. As such, common stock (equity) investments are higher on the risk scale, requiring a higher rate of return, and implicitly a higher cost of capital.

Q. What is the relevance of the cost of capital in rate regulation?

A. Rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. At

III. Analysis of the Cost of Capital

Q. What are the financial models typically employed in estimating the cost of equity for a company?

A. A variety of financial models are used in estimating the cost of equity. The most commonly used financial models in estimating the cost of equity in the electric utility industry include the Capital Asset Pricing Model (CAPM) and the Dividend Growth Model (DGM).

Q. Please explain the CAPM model.

A. The CAPM is a model of expected returns built on the notion that since investment risk can be reduced by diversification, investors are only compensated for assuming non-diversifiable risks. Specifically, the CAPM holds that the expected return, and hence cost of equity for a company, is described by the following equation:

Cost of Equity = Risk-Free Rate + Beta x Market Risk Premium

Where: "Beta" is a measure of the relative risk of the asset to the overall market

Q. Please explain the DGM model.

A. The DGM is a form of discounted cash flow analysis whereby equity value can be calculated by discounting to the present all expected dividends over some forecast horizon plus any residual value of equity at the end of the forecast horizon. Conversely, the DGM allows one to calculate the implied discount rate, or cost of equity, used by investors if the other inputs are known. The model can be readily applied to the common stock of some IOUs because these companies have a long history of dividend payments and usually a relatively stable rate of increase in dividends over time.

Q. Did you use the CAPM approach to calculate the cost of equity?

A. I did not use the CAPM approach in my analysis as I have found from prior research that, at times, the CAPM approach will yield unreasonably low betas given the characteristics of the electric utility industry. Since beta estimates figure heavily in the CAPM cost of capital calculation as a determination of individual company risk, I have not utilized this approach for the current proceeding. Therefore, I have used the traditional DGM model as the most appropriate estimate of the cost of equity.

Q. Please describe more specifically the DGM approach.

A. At the most general level, the DGM takes the following form:

$$SP_0 = \frac{DIV_1}{(1+r)^1} + \frac{DIV_2}{(1+r)^2} + \ldots + \frac{DIV_t}{(1+r)^t} + \frac{SP_t}{(1+r)^t} \qquad (1)$$

where: SP_0 = current stock price

SP_t = expected future stock price at time t

$DIV_1, \ldots, DIV_t$ = expected dividends at times 1, …, t

r = investors' expected rate of return, or the cost of equity

As equation (1) shows, today's stock price reflects future benefits to investors (dividends and stock price at a future date) and investors' expected rate of return. As I explained in Section II, the cost of equity for a company is equal to investors' expected return on the company's common stock. The DGM thus allows us to calculate the cost of equity using the following known inputs: the current stock price, the expected amount of future dividends up to time *t*, and the expected future stock price at time *t*.

Equation (1) is simplified if we assume that expected future dividends grow at a constant rate (g) in perpetuity:

$$SP_0 = \frac{DIV_1}{(r - g)}$$

where: g = investors' expected long-term rate of growth in dividends per share.

Under the assumption of constant growth, the cost of equity can be solved for as follows:

$$r = \frac{DIV_1}{SP_0} + g$$

The assumption that dividends grow at a constant rate forever is rather simplistic and may not accurately reflect investors' expectations. A somewhat less restrictive approach, the variable-growth DGM, distinguishes between the short-term growth rate and the long-term growth rate. There are a number of ways to implement the variable-growth DGM depending on the number of growth rate forecasts available and the time period covered by such forecasts. Unfortunately, there are no clear theoretical guidelines to dictate which form of the DGM should be used. This is why I estimated the cost of equity for IOUs using six alternative approaches.[3]

Q. For what set of companies did you estimate the DGM model?

A. For this analysis, I calculated the cost of equity for the same sample of 83 companies used by the OPUC staff in the UE-88 proceedings. Such a broad set of companies spans a wide range of risk levels allowing for a better assessment of the effect of the

[3] For further discussion of these six approaches to variable-growth DGM, see Stewart C. Myers and Lynda S. Borucki. "Discounted Cash Flow Estimates of the Cost of Equity Capital – A Case Study," *Financial Markets, Institutions & Instruments* 3, no. 3 (August 1994): 9-45.

change in risk due to the change in regulatory climate resulting from the preclusion of a return on the undepreciated Trojan balance.

Q. Are there any significant additional risks faced by PGE that the companies in your sample do not face?

A. Yes. I understand that Oregon is the only state that does not allow the previously authorized rate of return on the undepreciated balance of an investment retired early for economic reasons. As utilities typically operate one or more plants which have investment balances that comprise a substantial portion of the rate base, the additional risk of not having a return on the undepreciated investment balance disallowed is significant.

Q. How do these additional risks affect your estimate of PGE's cost of equity?

A. As I discussed above, investors demand compensation only for non-diversifiable risk. Thus, only non-diversifiable risks appropriately affect the cost of equity. Since the decision to retire a plant early for economic reasons is based on a wide range of factors such as the cost to build new generation, the efficiency of new generation, and demand for new generation, all of which are correlated with the U.S. economy, the decision to retire a plant is at least partially non-diversifiable.

As a result of the new regulatory environment in Oregon, utilities operating in the state carry significantly more non-diversifiable risk than typical utility companies operating in other states. Thus, investors will demand an above-average return on equity in order to invest in Oregon utilities relative to other electric utilities that do not face this significant risk factor of future disallowances of the return on undepreciated investments.

A more simplistic explanation of why the investor would demand higher returns can be understood from the investor's own perception of the expected value of the future returns from investments. Additional possibilities of disallowances such as the disallowance of the return on the Trojan investment lower the expected value of future investments. Investors will require a higher cost of capital to maintain a risk-adjusted expected return on equity consistent with the broader U.S. market.

Q. Does the specific disallowance of the return on PGE's undepreciated investment in Trojan have any other effect on the risk associated with PGE?

A. Yes. Assuming PGE must collect its undepreciated balance in the retired plant over 17 years, the immediate financial write-off under FAS 90 of approximately $150 million will have a significant effect on PGE's financial leverage.[4] As discussed above, as the share of debt increases in the company's capitalization, the returns to equity holders become more risky. Thus, the increase in financial leverage caused by the specific disallowance of the undepreciated balance in Trojan will increase the required return on equity demanded by potential investors.

Specifically, the resulting $150 million write-off on equity would have increased PGE's financial leverage ratio[5] from 56.18% to 58.98%.[6] This factor alone would have increased PGE's cost of equity from 11.6% to 11.8%.

Q. What are the results of your empirical analysis of the cost of equity for PGE?

A. The results are shown in PGE Exhibit 6603. These results are based on the 83 companies in the sample employed by the staff in their UE-88 analysis. The DGM

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[4] See testimony of Mr. Hager, PGE Exhibit 6400.
[5] Expressed as Total Debt/Total Capital.
[6] See testimony of Mr. Hager, PGE Exhibit 6400.

model generates results ranging from 11.4% to 13.9% for the 75th percentile under these six approaches.

Q. Why do you highlight the 75th percentile rather than the average or median?

A. I highlight the 75th percentile to reflect the additional non-diversifiable risk faced by PGE above and beyond the risks faced by the typical utility in the sample of 83 companies.

Q. Is the ROE figure of 13.1% put forth by Mr. Hager in PGE Exhibit 6400 consistent with the range of estimates given by the DGM model?

A. Yes. Consistent with the additional non-diversifiable risk of future disallowances of the return on an undepreciated investment now present only in Oregon, the relevant comparison is to evaluate PGE's ROE against riskier than average companies in the staff sample. The ROE figure of 13.1% put forth by PGE falls in the middle of the range of the 75th percentile estimate under each approach. Even at the 66th percentile, where fully one-third of the companies have higher calculated ROEs from the six approaches, the figure of 13.1% falls within the range of estimates.

Q. Is a 13.1% cost of equity rate consistent with other authorized ROEs in effect in 1994 for the utilities in the staff's sample?

A. Yes. As shown in PGE Exhibit 6604, authorized ROEs in effect in March 1995 ranged from 10.0 to 16.2%. Thus, the 13.1% cost of equity rate falls well within the range of authorized rates in effect in 1995.

Q. Are there any other negative consequences that Oregon's new regulatory regime will have on regulated utilities?

A. Yes. As discussed above, the introduction of the new regulatory regime and the specific effect on Trojan in 1995 would have forced PGE to take a financial write-off of approximately $150 million. As detailed in the testimony of Mr. Hager, this substantial write-off combined with the loss of the return on the undepreciated balance of PGE's Trojan investment would have led to a significant degradation in key financial ratios monitored by the credit rating agencies such as: EBIT interest coverage; total debt to capital; funds from operations interest coverage; funds from operations to total debt; and net cash flow to capital expenditures. As a result of the degradation in these ratios, PGE could have suffered from credit downgrades and, consequently faced higher future borrowing costs.

Q. Are there any measures the OPUC could undertake to mitigate the negative effect on PGE's credit ratings?

A. Yes. As discussed in the testimony of Mr. Hager, the OPUC could adjust the regulatory capital structure in setting PGE's cost of capital by increasing the proportion of the capital structure represented by equity. The resulting improvement in cash flows from such an adjustment would mitigate the degradation in the five key ratios discussed above.

IV. Qualifications

Q. Please describe your educational background and work experience?

A. I received a B.E.E. from the University of Virginia, and an M.A. and Ph.D. in applied mathematics from Harvard University.

I hold a faculty appointment (Dean Emeritus and William and Josephine Buchanan Professor of Management) at the Tuck School of Business at Dartmouth College. I also am on the board of directors of several companies. My professional and academic experience, education, publications, and directorships are described in more detail in the resume attached as PGE Exhibit 6601. My experience in areas that are directly relevant to the assignment embodied in this report is summarized below.

In my academic career, I have taught finance and quantitative analysis at three universities: Harvard, Duke, and Dartmouth. I have taught courses in corporate governance, private equity investing, and entrepreneurship at Dartmouth, and conducted research at Harvard, Duke, and Dartmouth.

In addition to my teaching and research activities, I have served as Dean of the Tuck School of Business at Dartmouth, Vice Provost for Planning at Duke, and Director of the Institute for Public Policy Studies at Duke. In these capacities, I have been responsible for the academic, financial, and administrative aspects of University programs. I currently hold an academic appointment as the Director of the Tuck Center for Private Equity and Entrepreneurship at Dartmouth, a research and education center I founded. In that position, I advise many new startup enterprises and the venture capital funds that finance them. In my professional activities, I serve on the investment advisory boards of the Arcadia Fund, Merrill Lynch Private Equity Partners, HealthPoint LLC, Altus Capital, and the Borealis Fund, and have served on the boards of five venture capital-funded enterprises. I have been a consultant for 30 years and have consulted to both private and public sector organizations.

I have served on the boards of directors of over 30 organizations. These have included not-for-profits, closely held companies, family-owned companies, and companies in capital-intensive cyclical industries. I have served on the boards of several companies involved in capital-intensive cyclical industries including aerospace, aviation, steel, energy (including an Independent Power Producer), and vehicle manufacturing. I have served on board committees with responsibilities for audit, strategy, capital investing, and governance. As a board member, I have participated in decisions regarding financing and competitive strategy including specific issues such as changes in control, acquisitions, divestiture, and liquidation.

Q. In what areas have you consulted?

A. I have consulted on issues of valuation, governance, planning, and strategy. As a consultant, I have worked extensively with the energy industry and also with companies in the railroad, automotive, steel, and appliance industries. My consulting work has addressed many of the same issues with which I have been involved, including governance structure, executive compensation, and profitability improvement.

Q. Have you testified as an expert witness?

A. Yes. I have served as an expert witness in regulatory, litigation, and legislative matters for a variety of industries. My expert testimony has primarily involved matters of financial economics and governance, including issues such as contract disputes, acquisition and sale of companies or divisions, changes in control and joint venture collaborations in industries including steel, electric and gas utilities, railroads, insurance, and financial services.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
6601	Witness Qualifications
6602	Risk Comparison of Alternative Investments
6603	Summary of Cost of Equity for Investor Owned Utilities
6604	Summary of Authorized Return on Equity for Staff Utility Sample

EXHIBIT 1
CURRICULUM VITAE

COLIN C. BLAYDON

The Tuck School of Business
Dartmouth College
100 Tuck Hall, Hanover, NH 03755
(603) 646-3160

ACADEMIC AND GOVERNMENT EMPLOYMENT & EXPERIENCE

1995-Present

William and Josephine Buchanan Professor of Management; Director, Center for Private Equity and Entrepreneurship; Dean Emeritus, The Tuck School of Business
Dartmouth College

Teaching and research in Entrepreneurship and Private Equity Finance. Teach elective courses in Private Equity Finance (130 students).

Current research topics include private equity best practices, securities and deal structure, venture capital valuation, and the strategies and governance of firms providing or receiving private equity financing.

1994-1995
Interim Dean, The Tuck School of Business
Dartmouth College

Chief academic and administrative officer during interim year.

<u>1993-1994</u>

Professor of Business Administration, The Tuck School of Business

Dartmouth College

Teaching in Entrepreneurship and Decision Science. Research on corporate governance and on corporate strategies of firms impacted by government policies and regulation.

<u>1990-1991</u>

Visiting Professor of Business Administration

Harvard Business School

Research on corporate governance and professional institutions. Private consulting on corporate governance and strategy. Expert witness in business litigation.

<u>1983-1990</u>

Dean, The Tuck School of Business

Dartmouth College

Dean of graduate business school and Professor of Business Administration. Senior academic officer responsible for all financial, administrative, and academic activities of Dartmouth's graduate business school. Presided over a 250 percent expansion of the financial activities of the school, initiated and completed the school's first independent capital campaign, expanded faculty and study body by 20 percent and recruited 80 percent of the current faculty, instituted a joint venture MBA program in Japan, and established an associated international management research institute in Tokyo. Personal research and teaching activities in the areas of corporate governance and control, and the impact of government policies and regulation on the private sector. Private consulting on corporate governance, strategy, and financial analysis.

<u>1975-1983</u>
Vice Provost and Professor
Duke University

Vice Provost for Academic Policy and Planning, and professor of Policy Sciences and Business Administration. Planning and budgeting for academic sector of the university. Teaching and research in corporate finance, public sector budgeting, and regulatory policy. Acting Director of the Institute of Policy Sciences, 1978. Chairman, National Academy of Sciences Panel on Vocational Education and Economic Development. Chairman of Inter-agency Task Force on ERISA, President's Reorganization Project. Research and consultation for a number of government agencies and private foundations.

<u>1973-1975</u>
Deputy Associate Director
Office of Management and Budget
(on leave from Harvard Business School)

Director of Special Studies and Management Division. Responsible for monitoring department and agency performance under the Presidential Objectives System and for analysis and development of new legislative initiatives in: Health Manpower, National Health Insurance, Pension Reform, Higher Education, and Housing Finance.

<u>1969-1973</u>
Assistant Professor
Harvard Business School

Teaching and research in Corporate Finance and Managerial Economics.

<u>1966-1969</u>
Staff Assistant to Assistant Secretary of Defense (Systems Analysis)
U.S. Department of Defense

Participant in design of planning and budgeting systems for Department of Defense Intelligence Resources. Member of Department of Defense Policy and Review Committee of the President's Space Task Group, Member of Secretary of Defense Committee for review of consolidated Intelligence Program, Member of Joint Committees for Preparation for Strategic Arms Limitations Talks (SALT).

BUSINESS EMPLOYMENT AND EXPERIENCE

2000-2003
Director and Consultant
LECG

Served as expert management, financial, and economic witness in business litigation and regulatory proceedings.

1981-2000
Director and Senior Advisor
Putnam, Hayes & Bartlett, Inc.

Responsible for studies on corporate strategy, organization, and management issues with particular emphasis on issues where government policies have impact on the private sector. Served as expert management, financial, and economic witness in business litigation and regulatory proceedings.

1992-1993
Executive Chairman
ITP Systems

Responsible for leadership of this privately-held engineering systems and software firm specializing in automation of manufacturing systems in automobile, semiconductor, aerospace, and electronics industries.

1975-1981
Principal
ICF Incorporated

Performed public policy and regulatory studies in areas of energy, private pensions, education finance, and regulated utilities.

DIRECTORSHIPS

- DHM Arcadia Partners, Member, Board of Advisors
- Merrill Lynch Private Equity Partners, Member, Board of Advisors
- The Council for Excellence in Government, Member, Board of Trustees, Chair, Audit Committee
- Business Intelligence Advisors, Inc., Member, Board of Directors
- Center for Private Equity and Entrepreneurship, Tuck School, Founding Director
- Borealis Ventures, Member, Board of Advisors
- Journal of Private Equity, Member, Advisory Board
- LECG LLC, former Member, Board of Directors
- The LTV Corporation, former Member, Board of Directors, Chair, Pension and Investments Committee and Board Affairs Committee
- Mercantile Trust N.A., former Member, Board of Directors
- ITP Systems, Inc., former Chairman, Board of Directors
- The Public Utility Policy Institute, former Member, Board of Directors
- Valley Forge Dental Associates, Inc., former Director
- International Management Research Institute of the International University of Japan, former Vice Chairman of the Board of Advisors

- University of Southern California School of Business Administration, former member of Board of Visitors
- Computer Consoles, Inc., former Director
- IMEC, Inc., former Director
- Linkletter Enterprises, Inc., former Director
- Lynn Management, Inc., former Director
- MICA, Inc., former Director
- Consolidated Power Corp., former Director
- Mainstream Software Corp., former Director
- The Washington Campus, former Member, Board of Directors
- Tuck Educational Loan Corporation, former Chairman
- Council for Opportunity in Graduate Management Education, former Chairman of Board of Trustees
- Tom's of Maine, former Member, Board of Directors
- The Lowell Whiteman School, former Member, Board of Trustees

EDUCATION

Ph.D. in Applied Mathematics, Harvard University, 1967
A.M. in Applied Mathematics, Harvard University, 1965
B.E.E., University of Virginia, 1962

HONORS

AEC Special Fellow, Sigma Xi, Tau Beta Pi, Eta Kappa Nu, Phi Eta Sigma (President), Raven Society

PUBLICATIONS

"LPs Need to Trust General Partners in Setting Valuations," *Venture Capital Journal,* March 2003, with Michael Horvath.

"The year of valuation guidelines," *The Private Equity Annual Review 2002*, with Michael Horvath and Fred Wainwright.

"GPs Say Valuation Standard Is 'Important' But Can't Agree On One," *Venture Capital Journal*, October 2002, with Michael Horvath.

"Minding the Store: GPs Face Up to Corporate Governance Issues, " *Venture Capital Journal,* July 2002, with M. Horvath.

"What's a Company Worth ? It Depends on Which GP You Ask," *Venture Capital Journal,* May 2002, with M. Horvath.

"Liquidation Preferences: What You May Not Know," *Venture Capital Journal,* March 2002, with M. Horvath.

"Bury the Ratchets," *Venture Capital Journal,* January 2002, with M. Horvath.

"Competing in New Deregulated Gas Markets," *Symposium on the Future of the Gas Industry in the New Competitive Market,* The Institute of Economic Affairs, April 1994.

"Stochastic Approximation," with R.L. Kashyap and K.S. Fu in A Prelude to Neural Networks, Prentice Hall, 1994 (re-publication).

"Applications of the Stochastic Approximation Methods," with R.L. Kashyap and K.S. Fu in A Prelude to Neural Networks, Prentice Hall, 1994 (re-publication).

"Tuck in Japan," *Selections*, Autumn 1989.

"Report of The AACSB Task Force on Outcome Measurement," report of the American Assembly of Collegiate Schools of Business' Task Force, June 1989 (co-authored).

"Understanding the MBA," *Dartmouth Business Forum*, Spring 1989.

"How to Educate Your Child to Take Over the Family Business...Or Any Business," *Boardroom Reports*, January 1, 1988.

"State Policies Under Pressure," Chapter 7 of *Drawing the Line on Natural Gas Regulation: The Harvard Study on the Future of Natural Gas,* edited by Joseph P. Kalt and Frank C. Schuller (Quorum Books, 1987).

Education for Tomorrow's Jobs, report of the Committee on Vocational Education and the Economic Development of Depressed Areas. C. Blaydon, chair, S. Sherman, editor; National Academy of Sciences, 1983.

"Alternative Electricity Futures: Review and Analysis," report to the Electricity Policy Project, U.S. Department of Energy, September 1982, with W.W. Hogan, W.H. Hieronymus, and M.M. Schnitzer.

"Retirement Program Coverage," in *Retirement Income and the Economy: Increasing Income for the Aged,* edited by Dallas L. Salisbury (Employee Benefits Research Institute, 1981).

"Private Pension Forecasts," with D. Kennel, H. Ting, and J. Valiente. Working paper for U.S. Department of Labor, 1980.

"Coverage, Participation, and Vesting in Private Pension Plans," with D. Kennell, H. Ting, and J. Valiente. Working paper for U.S. Department of Labor, 1981.

"Marginal Cost and Rate Structure Design for Retail Sales of Natural Gas, " in *Problems in Regulatory Economics* (Ballinger Press, 1979), with W. Magat and C. Thomas.

"Natural Gas Rate Design," U.S. Department of Energy Report, September 1981, with A. Brooks and S. Seeker.

"Policy Research and Federal Energy Regulation," AAAS Symposium, July 1979.

"Natural Gas and the Economy," Symposium on Energy and the Economy, The Energy Bureau, Washington, D.C., September 1980.

"State Policies and Private higher Education," *Public Policy and Private Higher Education,* The Brookings Institute, Fall 1977.

"Financing the Cites: An Issue Agenda,' *Duke Law Journal,* Spring 1977, with S.P. Gilford.

"Income Support Policies and Family Structure," *Daedalus*, Spring 1977.

Federal Response on Student Loans: Comment, Student Loans: Problems and Policy Alternatives, edited by Lois Rice (College Entrance Examination Board, New York, 1977).

"Impact of the National Energy Plan Coal Replacement Incentives on Electric utility Investment Decisions," Phase I Report, U.S. Department of Energy, August 13, 1977, with S. Seeber.

"Reorganization of Administrative Responsibilities Under the Employee Retirement Income Security Act of 1974 (ERISA)," President's Reorganization Project, 1978.

"Natural Gas Resources," prepared testimony on behalf of the New Jersey Public Advocate before the New Jersey Utility Commission, June 1976.

"Summary of Diabetes Program Funding," in *Report of the National Commission on Diabetes to the Congress of the United States,* Vol. IV, December 10, 1975.

"Incentive Contracts and Competitive Bidding: A Comment," *American Economic Review,* November-December 1974, with P.W. Marshall.

"Bidding for Simple Incentive Contracts," working paper HBS 72-31, presented as a contributed paper at AIDS Fourth Annual Meeting, November 1972.

"An Introduction to Time Series Models," working paper HBSA 72-73, presented as an invited tutorial talk at the AIDS Third Annual Meeting, October 1971.

"Stochastic Approximation," in *Adaptive and Learning Systems,* edited by J.M. Mendel (Academic Press, 1970) with K.S. Fu and R.L. Kashyap.

"Applications of Stochastic Approximation" in *Adaptive and Learning Systems,* edited by J.M. Mendel (Academic Press, 1970), with K.S. Fu and R.L. Kashyap.

"Comments on the Estimation of Distribution Functions," *IEEE Transactions on Information Theory,* Vol. IT-16, No. 2, March 1970, p. 226, with T. Wagner and R.L. Kashyap.

"Recovery of Regression Functions," *Proceedings of the Hawaii International Conference on Systems Sciences,* January 1968, with R.L. Kashyap.

"Approximation of Distribution and Density functions," *Proceedings of the IEEE,* Vol. 55, No. 2, February 1967.

"Recursive Algorithms for Pattern Classification," *Cruft Lab Technical Report*, No. 250, Harvard University, 1967. (The technical report version of doctoral thesis available upon request.)

"On the Abstraction Problem in Pattern Classification," *proceedings of the National Electronics Conference,* Vol. 22, October 1966, with Y.C. Ho.

"Recovery of Functions from Noisy Measurements Taken at Randomly Selected Points and Its Application to Pattern Classifications," *Proceedings of the IEEE,* Vol. 54, No. 8, August 1966, with R.L. Kashyap.

"On a Pattern Classification Result of Aizerman, Braverman and Rozonoer," in *IEEE Transactions on Information Theory*, Vol. IT-12, No. 1, January 1966, with R.L. Kashyap.

"Experiments with a Pattern Classification Technique," *Cruft Lab Technical Report*, Harvard University, 1965, with Y.C. Ho, R.L. Kashyap, and A. Arcese.

WORKING PAPERS

"Valuation, Reporting and Disclosure Issues in Private Equity," with F. Wainwright

"Best Practices in Board Participation in Portfolio Companies," with F. Wainwright

SPEECHES AND ACTIVITIES

January 2004, Private Equity COO and CFO Conference, Panel Leader, New York, NY.

July 2003, Private Equity COO and CFO Conference, New York, NY.

July 2003, Private Equity COO and CFO Conference, Keynote Speaker, London, England.

September 2002, ILPA Conference, Toronto, Ontario Canada.

April 2002, Private Equity Presentation to Dartmouth Research Development and Officers, Hanover, NH.

April 2002, Private Equity Presentation to Edwards & Angel Law Firm, Boston, MA.

December 2001, Attended "Private Equity Analyst Conference", New York, NY.

November 2001, Moderated Panel on Foundations for the Initiative for Corporate Citizenship, Hanover, NH.

May 2001, Attended "Nantucket Conference on Entrepreneurship and Innovation," Nantucket, MA.

May 2001, Attended JFK Teaching Workshop, Harvard Business School, Cambridge, MA.

April 2001, "Visioning the Future," a panel discussion at the final plenary of the AACSB Annual Conference, New York, NY.

March 2001, Participated in "Private Equity Roundtable for Tuck Today," Hanover, NH.

July 2000, Participated in "Enterprise, Venture Finance & Emerging Technologies: Enhancing UK-US Opportunities in Public Interest" Conference, US Embassy, London, UK.

July 2000, "What Lessons from Successes and Failures of American Policies and Practices Might be Especially Applicable to the UK?" a panel discussion at the UK/US Conference on Enterprise and Technology, London, UK.

July 2000, "What do Venture Capitalists look for in Startups and Growing Businesses?" a panel discussion at the UK/US Conference on Enterprise and Technology, London, UK.

April 1997, "European Private Equity," presented at The Russell Capital Seminar on Private Equity, The Hoover Institute, Stanford, CA.

November 1995, "Unbundling and Transmission Pricing in the Natural Gas Industry," an invited debate with Charles Chichetti before the Federal Energy Regulatory Commission.

April 27, 1994, "Competing in the New Deregulated Gas Markets," Symposium on Future of the Gas Industry in the New Competitive Market, The Institute of Economic Affairs, London, UK.

February 7, 1994, "Fundraising, School Mission, and School Leadership," AACSB Conference on Fundraising, Washington, D.C.

August 5, 1992, "Economics of Incremental Pricing for Natural Gas Transportation," testimony before the Federal Energy Regulatory Commission.

November 1991, "Rolled-In vs. Incrementation Pricing of Natural Gas Transportation," testimony before the Federal Energy Regulatory Commission.

June 5, 1990, addressed Company of the Year Award Dinner of the Trinidad Express Newspapers Limited, Port of Spain, Trinidad.

March 21, 1990, "The Importance of Continued Education to Strengthen the Management and Financial Skills of Small Business Owners," presented at the Houston Business Council's Annual Scholarship and Awards Luncheon, Houston, TX.

March 1990, guest speaker on Financial News Network's show, *The Private Motive* on the subject: "Should You Get an MBA?"

January 1990, "Management Education and the Global Challenge of the Next Decade," presented at the Global Seminar and Symposium, International University of Japan, Tokyo, Japan.

June 1989, "The International Challenge: Graduate Management Education in Europe and Japan," presented at the Annual Meeting of the Graduate Management Admission Council, Baltimore, MD.

1988-1989, chaired the American Assembly of Collegiate Schools of Business' Task Force on Outcome measurement (see report of June 1989).

1987-1990, chaired the American Assembly of Collegiate Schools of Business' Committee on Government Relations.

May 1987, "Strategy and Competition," presented at the Mid-Atlantic Association of Headmasters in Private Secondary Schools.

November 1985, "Management and Strategy in Private Secondary Education," presented at the Headmistress Association of the East, Princeton, NJ.

September 10, 1985, "Managing the Change from Regulated to Deregulated Business," presented at a conference for senior lawyers by Burlington Northern, Laguna Nigel, CA.

October 1982, "Alternative Energy Pictures: Duplications for Electric Utilities," presented at the Conference on Energy and the Economy, The Energy Bureau.

September 1982, "Planning Systems for Electric Utilities," presented at the EEI Conference, Washington, DC.

June 1982, "Pattern Recognition and Economic Analysis," invited comments at the IFAC/IFORS Conference on International Economic Dynamics and Control, Federal Reserve Board.

1982, "The Electric Utility Industry in the 1980s," presented at the 4th Annual Conference on Energy and the Economy, The Energy Bureau.

September 1980, "Gas Distribution Planning and Marginal Costs," presented at the Annual Research Conference of the National Association of Regulatory Utility Commissioners, Columbus, OH.

April 1979, "Reorganization: Issues, implication and Opportunities for U.S. Natural Resources Policy", sponsored by the Center for Resource and Environmental Research, participant commendation, Duke University, Durham, NC.

November 1978, "Economics of Public Pension Plans," presented at the Pension Regulation Symposium, sponsored by *Duke Law Journal*, Washington, DC.

October 1978, "Regulation of Public Employee Pensions," *Duke Law Journal* Symposium, Durham, NC

November 1977, "National Income Policy," at the Southern Pension Conference, Southern Pines, NC.

October 1977, "Federal Government Reorganization of Private Pension Regulation," Presented at the American Bar Association meeting, Washington, DC.

May 24, 1977, "The Politics of Biomedical Research Funding: The Case of Diabetes," presented at an NIH Symposium on The Politics of Health, Washington, DC.

November 1976, "Use and Abuse of Human Capital Theory," presented at the Southern Economics Association Annual Meeting, Atlanta, GA.

December 1976, "The Outlook for Federal Aid to State and Local Government," ISI Symposium on *Federal Aid to Local Government*, Atlanta, GA.

March 1976, "Special Initiatives and Resource Allocation in Biomedical Research," *Law and Contemporary Problems*, Symposium on FY 1977 budget, Washington, DC.

January 1976, "The Federal Budget for Higher Education," introductory comments as chairman and organizer of ACE Symposium on FY 1977 budget, Washington, DC.

1976, "Federal Aid to State and Local Government," presented at the Annual Meeting of North Carolina Municipal Budget Officers Association, Raleigh, NC.

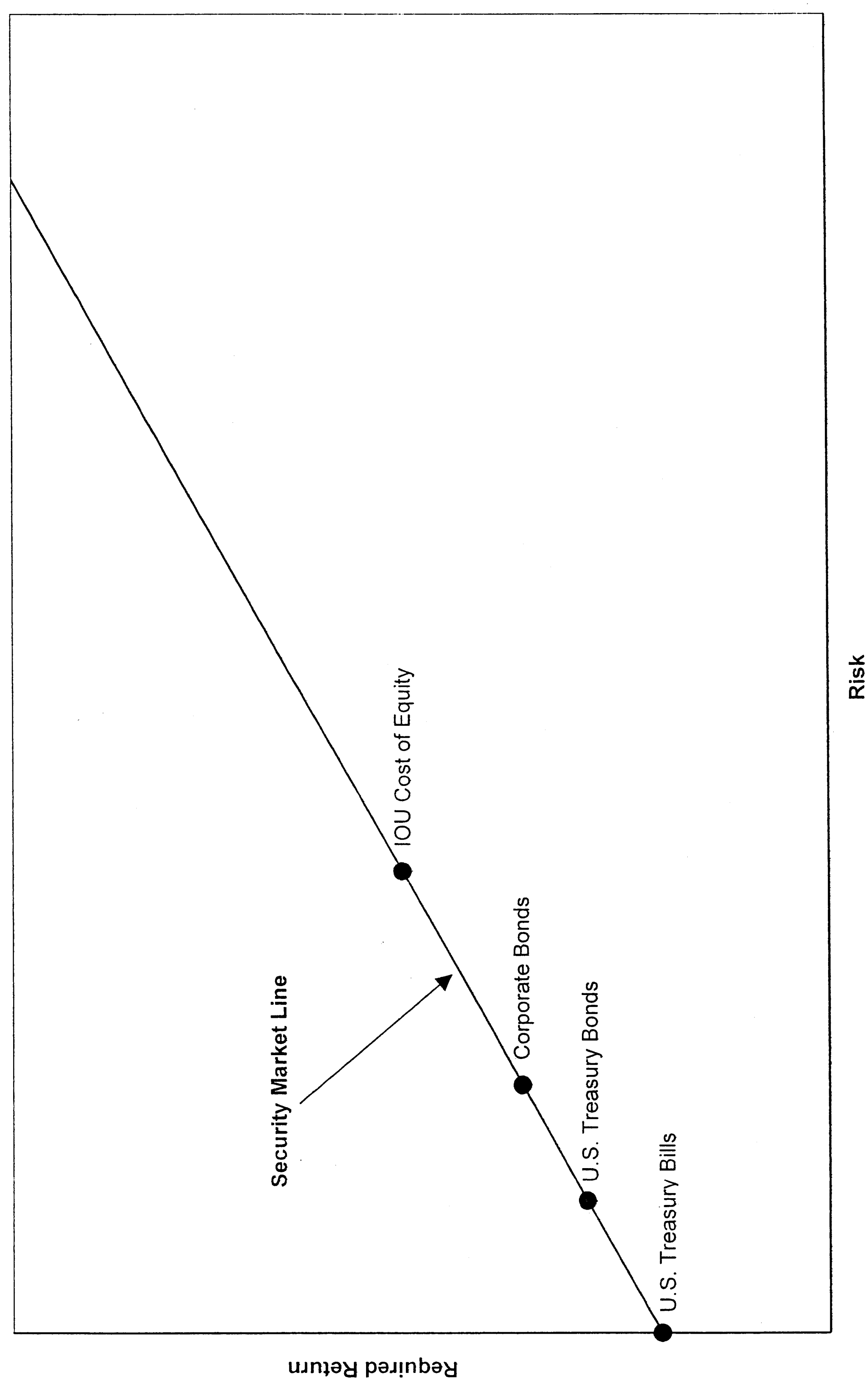
TESTIMONY WITHIN PRIOR FOUR YEARS

Date	On Behalf Of	Before	Product
2005	Deloitte & Touche LLP	The American Arbitration Association Case No. 1340004477	Deposition and Expert Report
2004	Deloitte & Touche LLP	The American Arbitration Association Case No. 11 Y 136002122	Deposition and Expert Report
2004	Artemis S.A., Artemis Finance S.N.C., Artemis America, and Francois Pinault ("Artemis")	U.S. District Court – Central District of California Case No. CV-99-02829 AHM (CWx)	Deposition and Expert Report
2004	Deloitte & Touche LLP	The American Arbitration Association File No.51Y 168 00590 01	Expert Testimony, Deposition and Report
2004	Central Texas Airborne Systems	U.S. District Court – Northern District of California	Deposition and Expert Report
2004	Aquila Inc.	In the Court of Chancery of the State of Delaware Civil Action File no 19610	Deposition and Expert Report
2003	Attala Energy Company,LLC	The American Arbitration Association Case No. 16Y 198 002803	Expert Testimony, Deposition and Report

Date	On Behalf Of	Before	Product
2003	Madison Gas and Electric Company	The Public Service Commission of Wisconsin Docket 3270-UR-112	Expert Testimony and Report
2003	Wisconsin Energy	The Public Service Commission of Wisconsin Docket 05-CE-130	Expert Testimony and Report
2003	DPL Inc.	Court of Common Pleas – Hamilton County, Ohio	Deposition
2003	Otto Candies LLC et.al.	U.S. District Court – Eastern District of Louisiana Civil Action 99-CV-3692	Expert Testimony and Report
2002	Wisconsin Energy	The PUC/Wisconsin Electricity Commission	Expert Testimony and Reports
2002	B/E Aerospace	International Chamber of Commerce – International Court of Arbitration ICC Case No. 11 326/BWD	Affidavit and Testimony
2002	Scott Peltz as Liquidating Trustee of USN	United District Court – District of Delaware Case No. 00-CV-996 (RRM)	Expert Testimony and Report
2001	Virginia Electric and Power Company	Commonwealth of Virginia – State Corporation Commission Case No. PUE000584	Direct and Rebuttal Testimony
2001	Scott Peltz as Liquidating Trustee of USN	American Arbitrators Association	Exhibits and Testimony

Date	On Behalf Of	Before	Product
2001	GATX Corporation	US District Court – No. District of CA Case No. C96-2494 CW	Affidavit and Testimony

Risk Comparison of Alternative Investments



Summary of Estimated Cost of Equity for Investor Owned Utilities

Companies Used in Oregon Public Utility Commission Staff Analysis

	CG-VL	CG-IBES	CG-SG	VG-Q920	VG-IBES	VG-SG
ALLEGHENY POWER SYSTEM, INC	12.2%	9.9%	10.7%	9.8%	10.1%	10.8%
AMERICAN ELECTRIC POWER, INC	12.6%	10.5%	10.7%	10.6%	10.6%	10.8%
ATLANTIC ENERGY, INC.	13.3%	10.9%	11.8%	12.9%	10.9%	11.6%
BALTIMORE GAS AND ELECTRIC CO.	13.4%	10.7%	10.2%	10.9%	10.8%	10.4%
BOSTON EDISON CO	11.7%	10.6%	10.1%	6.0%	10.8%	10.3%
CAROLINA POWER AND LIGHT	9.7%	9.7%	9.0%	7.8%	9.9%	9.2%
CENTERIOR ENERGY CORP.	44.8%	10.6%	12.6%	8.2%	11.1%	12.8%
CENTRAL & SOUTH WEST CORP.	18.4%	11.7%	10.8%	11.3%	11.8%	10.9%
CENTRAL HUDSON GAS & ELECTRIC CORP.	11.0%	10.9%	10.9%	12.7%	11.0%	11.0%
CENTRAL LOUISIANA ELECTRIC CO., INC.	11.6%	9.8%	9.4%	17.0%	9.8%	9.4%
CENTRAL MAINE POWER CO.	6.4%	11.3%	10.7%	24.9%	11.4%	10.8%
CENTRAL VERMONT PUBLIC SERVICE CORP.	13.6%	13.5%	12.8%	17.7%	14.0%	13.5%
CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	13.8%	11.5%	10.8%	10.7%	11.6%	11.1%
CINCINNATI GAS & ELECTRIC CO.	14.1%	11.1%	12.1%	12.1%	11.2%	12.0%
CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	9.5%	12.1%	10.1%	16.1%	12.0%	10.3%
CMS ENERGY CORP.	14.4%	9.4%	11.2%	7.4%	9.5%	11.1%
COMMONWEALTH EDISON CO.	15.5%	13.5%	9.8%	9.3%	15.1%	11.9%
COMMONWEALTH ENERGY SYSTEM	8.6%	11.0%	11.4%	13.8%	10.9%	11.2%
CONSOLIDATED EDISON CO. OF NEW YORK, INC.	10.4%	9.9%	10.7%	10.5%	9.7%	10.4%
DELMARVA POWER & LIGHT CO.	9.8%	11.7%	10.0%	14.6%	11.6%	10.1%
DOMINION RESOURCES	10.1%	10.2%	10.2%	10.8%	10.3%	10.3%
DPL INC. (DAYTON POWER & LIGHT CO.)	10.9%	10.2%	9.6%	8.6%	10.3%	9.8%
DQE, INC. (DUQUESNE LIGHT CO.)	9.7%	9.6%	9.8%	8.8%	9.6%	9.8%
DUKE POWER CO.	10.4%	9.2%	9.5%	9.2%	9.2%	9.4%
EASTERN UTILITIES ASSOCIATES	9.8%	10.8%	11.2%	13.5%	10.8%	11.1%
EMPIRE DISTRICT ELECTRIC	16.9%	12.2%	10.5%	10.0%	12.6%	11.2%
ENTERGY CORP.	12.2%	11.4%	10.0%	16.2%	11.5%	10.3%
FLORIDA PROGRESS CORP.	13.0%	10.5%	10.5%	9.8%	10.7%	10.7%
FPL GROUP, INC	11.9%	9.7%	9.5%	9.5%	9.7%	9.6%
GENERAL PUBLIC UTILITIES CORP.	10.6%	10.3%	10.5%	9.7%	10.4%	10.6%
GREEN MOUNTAIN POWER CORP.	12.2%	10.3%	10.7%	10.9%	10.5%	10.9%
HAWAIIAN ELECTRIC INDUSTRIES, INC.	13.9%	11.8%	10.3%	10.5%	12.2%	10.8%
HOUSTON INDUSTRIES, INC.	15.1%	11.1%	12.5%	11.6%	11.1%	12.3%
IDAHO POWER CO.	11.0%	11.3%	9.8%	12.5%	11.9%	10.5%
IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	13.2%	11.3%	11.6%	12.2%	11.4%	11.7%
INTERSTATE POWER CO.	20.0%		11.6%			
IOWA-ILLINOIS GAS & ELECTRIC CO.	13.8%	11.8%	11.3%	11.4%	12.1%	11.7%
IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	21.1%	11.1%	10.8%	12.4%	11.2%	10.9%
KANSAS CITY POWER & LIGHT CO.	13.8%	10.2%	10.1%	8.1%	10.4%	10.3%
KU ENERGY CO.	10.9%	9.5%	9.9%	11.3%	9.6%	10.0%
LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	13.3%	9.5%	9.5%	9.1%	9.7%	9.6%
LONG ISLAND LIGHTING CO.	11.8%	12.2%	11.7%	14.1%	12.4%	12.0%
MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	15.8%	10.9%	11.8%	11.3%	11.0%	11.8%
MINNESOTA POWER & LIGHT CO.	14.0%	11.1%	10.4%	11.1%	11.6%	11.1%
NEVADA POWER CO.	9.4%	11.4%	11.7%	12.6%	11.5%	11.7%
NEW ENGLAND ELECTRIC SYSTEM	8.8%	10.3%	10.3%	8.4%	10.4%	10.4%
NEW YORK STATE ELECTRIC & GAS CORP.	13.2%	13.8%	12.9%	15.3%	14.2%	13.5%
NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	16.7%	10.2%	10.7%	10.1%	10.2%	10.7%
NORTHEAST UTILITIES	23.0%	11.6%	12.2%	8.1%	11.7%	12.1%
NORTHERN STATES POWER CO.	19.2%	17.0%	16.4%	14.9%	17.3%	16.8%
OHIO EDISON CO.	14.0%	11.1%	11.2%	11.8%	11.3%	11.4%
OKLAHOMA GAS & ELECTRIC CO.	12.5%	9.5%	10.6%	11.7%	9.7%	10.7%
ORANGE & ROCKLAND INDUSTRIES, INC.	11.6%	11.6%	11.0%	11.4%	11.9%	11.4%
PACIFIC GAS & ELECTRIC CO.	14.1%	10.5%	11.9%	7.9%	11.1%	12.2%
PECO ENERGY	11.4%	10.0%	10.7%	10.3%	10.1%	10.7%
PENNSYLVANIA POWER & LIGHT CO.	10.0%	10.0%	11.4%	12.3%	10.0%	11.2%
PORTLAND GENERAL CORP.	10.7%	10.1%	10.4%	14.8%	9.9%	10.2%
POTOMAC ELECTRIC POWER CO.	10.6%	10.3%	10.8%	12.2%	10.4%	10.9%
PUBLIC SERVICE ENTERPRISE GROUP, INC.	10.5%	11.1%	10.9%	9.2%	11.3%	11.1%
PUBLIC SERVICE OF COLORADO	9.9%	9.9%	11.0%	10.4%	10.2%	11.1%
PUGET SOUND POWER & LIGHT	9.7%	11.6%	12.9%	14.6%	12.0%	13.0%
ROCHESTER GAS & ELECTRIC CORP.	14.4%	10.5%	10.9%	7.7%	10.7%	11.0%
SAN DIEGO GAS & ELECTRIC CO.	14.0%	10.5%	12.1%	10.5%	10.7%	12.1%
SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	8.4%	9.8%	11.7%	12.0%	9.8%	11.5%
SCE CORP (SOUTHERN CALIF. EDISON CORP.)	9.9%	9.5%	11.3%	10.7%	9.7%	11.2%
SIERRA PACIFIC RESOURCES	7.8%	9.9%	8.5%	9.7%	10.0%	8.8%
SOUTHERN CO	11.6%	10.0%	9.7%	10.2%	10.1%	9.9%
SOUTHERN INDIANA GAS & ELECTRIC CO.	7.7%	9.6%	9.7%	11.9%	9.6%	9.7%
SOUTHWESTERN PUBLIC SERVICE CO.	10.9%	10.2%	11.5%	12.4%	10.5%	11.5%
ST. JOSEPH LIGHT & POWER CO.	12.4%	8.7%	7.6%	9.1%	9.3%	8.4%
TECO ENERGY INC. (TAMPA ELECTRIC)	14.9%	10.0%	12.4%	9.6%	10.0%	12.2%
TEXAS UTILITIES CO.	11.0%	12.1%	10.6%	15.2%	12.8%	11.6%
THE DETROIT EDISON CO	5.2%	10.1%	11.0%	18.8%	10.3%	11.0%
THE MONTANA POWER CO.	10.5%	11.3%	10.7%	12.1%	11.3%	10.8%
TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	20.4%	11.5%	1.8%	4.0%	13.7%	5.3%
UNION ELECTRIC CO.	10.0%	10.4%	9.1%	10.4%	10.3%	9.1%
UNITED ILLUMINATING CO	13.1%	12.8%	11.0%	12.6%	13.0%	11.5%
UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	17.2%	12.0%	12.2%	13.7%	12.1%	12.3%
WASHINGTON WATER POWER CO	13.9%	10.9%	11.5%	13.2%	11.2%	11.7%
WESTERN RESOURCES, INC	8.0%	10.5%	9.8%	14.3%	10.7%	10.0%
WISCONSIN ENERGY CORP.	11.5%	10.2%	10.4%	8.8%	10.3%	10.5%
WISCONSIN PUBLIC SERVICE CORP.	7.3%	9.3%	9.5%	11.3%	9.4%	9.6%
WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	12.6%	9.8%	10.5%	8.6%	9.9%	10.5%
Mean	**12.75%**	**10.81%**	**10.71%**	**11.46%**	**11.00%**	**10.92%**
Standard Deviation	4.83%	1.22%	1.54%	3.02%	1.36%	1.34%
Mean + 1 Standard Deviation	17.57%	12.02%	12.25%	14.49%	12.36%	12.26%
Median	**11.94%**	**10.56%**	**10.72%**	**11.17%**	**10.73%**	**10.90%**
60th Percentile	13.04%	10.93%	10.89%	11.76%	11.08%	11.12%
66th Percentile	13.32%	11.08%	11.02%	12.11%	11.24%	11.21%
70th Percentile	13.80%	11.24%	11.25%	12.36%	11.36%	11.40%
75th Percentile	13.94%	11.35%	11.45%	12.63%	11.55%	11.59%
Min	5.18%	8.75%	1.79%	3.97%	9.18%	5.28%
Max	44.81%	16.96%	16.40%	24.86%	17.28%	16.84%

Summary of Estimated Cost of Equity for Investor Owned Utilities

	CG-VL	CG-IBES	CG-SG	VG-Q920	VG-IBES	VG-SG
Mean	12.7%	10.8%	10.7%	11.5%	11.0%	10.9%
Median	11.9%	10.6%	10.7%	11.2%	10.7%	10.9%
Min	5.2%	8.7%	1.8%	4.0%	9.2%	5.3%
Max	44.8%	17.0%	16.4%	24.9%	17.3%	16.8%

60th Percentile	13.04%	10.93%	10.89%	11.76%	11.08%	11.12%
66th Percentile	13.32%	11.08%	11.02%	12.11%	11.24%	11.21%
70th Percentile	13.80%	11.24%	11.25%	12.36%	11.36%	11.40%
75th Percentile	13.94%	11.35%	11.45%	12.63%	11.55%	11.59%

Notes:

CG-VL = Constant-Growth DGM Model with Value Line Forecast
CG-IBES = Constant-Growth DGM Model with Thomson Financial Forecast
CG-SG = Constant-Growth Sustainable-Growth DGM Model with Value Line Forecast
VG-Q920 = Variable-Growth DGM Model with Thomson Financial Qtrs. 9 to 20 Earnings Growth Rate
VG-IBES = Variable-Growth DGM Model with Thomson Financial Mean 5 Year Earnings Growth Forecast
VG-SG = Variable-Growth Sustainable-Growth DGM Model with Thomson Financial Forecasts and Value Line Forecasts

These models are described in detail by Stewart C. Myers and Lynda S. Borucki in "Discounted Cash Flow Estimates of the Cost of Equity Capital--A Case Study," Financial Markets, Institutions & Instruments, V. 3, N. 3, August 1994, pp. 9-45.

Investor Owned Utilities
Constant-Growth DGM Model with Value Line Forecast (CG-VL DGM)+

Source: CRSP; *Value Line*

	Company	[1] Q3 1994 Dividend	[2] Q4 1994 Projected Dividend	[3] Q3 1994 Stock Price	[4] Current EPS	[5] Projected EPS	[6] Quarterly Dividend Yield	[7] Annual Growth Rate	[8] Qtrly Growth Rate	[9] CG-VL DGM ROE
1	ALLEGHENY POWER SYSTEM, INC.	0.410	0.414	21.417	1.88	2.20	1.93%	4.01%	0.99%	12.20%
2	AMERICAN ELECTRIC POWER, INC.	0.600	0.606	31.125	2.70	3.20	1.95%	4.34%	1.07%	12.62%
3	ATLANTIC ENERGY, INC.	0.385	0.389	17.625	1.80	2.10	2.21%	3.93%	0.97%	13.31%
4	BALTIMORE GAS AND ELECTRIC CO.	0.380	0.386	22.958	1.85	2.35	1.68%	6.16%	1.51%	13.37%
5	BOSTON EDISON CO.	0.440	0.445	25.667	2.28	2.70	1.73%	4.32%	1.06%	11.66%
6	CAROLINA POWER AND LIGHT	0.425	0.428	26.458	2.23	2.50	1.62%	2.90%	0.72%	9.67%
7	CENTERIOR ENERGY CORP.	0.200	0.215	9.792	0.55	1.75	2.20%	33.56%	7.50%	44.81%
8	CENTRAL & SOUTH WEST CORP.	0.425	0.435	22.458	1.72	2.50	1.94%	9.80%	2.36%	18.35%
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.520	0.523	25.500	2.68	2.95	2.05%	2.43%	0.60%	11.04%
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.365	0.369	23.000	1.78	2.15	1.61%	4.83%	1.19%	11.65%
11	CENTRAL MAINE POWER CO.	0.225	0.224	11.500	1.65	1.55	1.95%	-1.55%	-0.39%	6.38%
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.355	0.357	13.417	1.64	1.80	2.66%	2.35%	0.58%	13.63%
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.615	0.622	29.833	2.60	3.15	2.09%	4.91%	1.21%	13.84%
14	CINCINNATI GAS & ELECTRIC CO.	0.430	0.436	22.417	2.16	2.70	1.95%	5.74%	1.40%	14.09%
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.500	0.502	27.375	2.51	2.70	1.83%	1.84%	0.46%	9.49%
16	CMS ENERGY CORP.	0.210	0.215	22.208	1.90	2.80	0.97%	10.18%	2.45%	14.41%
17	COMMONWEALTH EDISON CO.	0.400	0.408	23.333	1.88	2.55	1.75%	7.92%	1.92%	15.51%
18	COMMONWEALTH ENERGY SYSTEM	0.750	0.751	39.667	4.37	4.50	1.89%	0.74%	0.18%	8.57%
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.500	0.503	26.958	2.66	2.95	1.87%	2.62%	0.65%	10.45%
20	DELMARVA POWER & LIGHT CO.	0.385	0.386	18.875	1.76	1.85	2.05%	1.25%	0.31%	9.77%
21	DOMINION RESOURCES	0.635	0.640	37.083	3.12	3.50	1.72%	2.91%	0.72%	10.15%
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.295	0.298	20.042	1.42	1.70	1.49%	4.60%	1.13%	10.90%
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.420	0.424	29.917	2.72	3.15	1.42%	3.74%	0.92%	9.69%
24	DUKE POWER CO.	0.490	0.496	38.667	2.80	3.40	1.28%	4.97%	1.22%	10.40%
25	EASTERN UTILITIES ASSOCIATES	0.385	0.388	24.083	2.44	2.75	1.61%	3.04%	0.75%	9.78%
26	EMPIRE DISTRICT ELECTRIC	0.320	0.326	16.792	1.16	1.60	1.94%	8.37%	2.03%	16.87%
27	ENTERGY CORP.	0.450	0.455	24.542	2.62	3.10	1.85%	4.30%	1.06%	12.16%
28	FLORIDA PROGRESS CORP.	0.495	0.502	28.500	2.26	2.80	1.76%	5.50%	1.35%	13.03%
29	FPL GROUP, INC.	0.420	0.426	31.792	2.75	3.50	1.34%	6.21%	1.52%	11.94%
30	GENERAL PUBLIC UTILITIES CORP.	0.450	0.454	25.542	2.65	3.00	1.78%	3.15%	0.78%	10.61%
31	GREEN MOUNTAIN POWER CORP.	0.530	0.534	25.292	2.20	2.50	2.11%	3.25%	0.80%	12.18%
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.580	0.588	31.875	2.38	3.00	1.85%	5.96%	1.46%	13.88%
33	HOUSTON INDUSTRIES, INC.	0.750	0.761	35.042	3.20	4.00	2.17%	5.74%	1.40%	15.08%
34	IDAHO POWER CO.	0.465	0.468	24.083	1.97	2.20	1.94%	2.80%	0.69%	10.97%
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.525	0.531	26.958	2.45	2.95	1.97%	4.75%	1.17%	13.15%
36	INTERSTATE POWER CO.	0.520	0.532	22.875	1.73	2.50	2.33%	9.64%	2.33%	19.96%
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.433	0.438	21.208	1.85	2.25	2.06%	5.02%	1.23%	13.85%
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.530	0.546	30.042	2.00	3.25	1.82%	12.91%	3.08%	21.09%
39	KANSAS CITY POWER & LIGHT CO.	0.380	0.386	21.417	1.66	2.10	1.80%	6.05%	1.48%	13.78%
40	KU ENERGY CO.	0.410	0.414	26.708	2.11	2.50	1.55%	4.33%	1.07%	10.89%
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.538	0.547	38.042	2.47	3.25	1.44%	7.10%	1.73%	13.28%
42	LONG ISLAND LIGHTING CO.	0.445	0.446	17.583	2.15	2.25	2.54%	1.14%	0.28%	11.78%
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.400	0.409	27.375	2.00	2.85	1.49%	9.26%	2.24%	15.79%
44	MINNESOTA POWER & LIGHT CO.	0.505	0.512	26.583	2.20	2.75	1.93%	5.74%	1.40%	14.00%
45	NEVADA POWER CO.	0.400	0.401	20.500	1.76	1.85	1.96%	1.25%	0.31%	9.39%
46	NEW ENGLAND ELECTRIC SYSTEM	0.575	0.577	32.083	3.13	3.30	1.80%	1.33%	0.33%	8.79%
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.550	0.553	21.417	2.33	2.55	2.58%	2.28%	0.57%	13.20%
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.360	0.369	28.500	2.31	3.50	1.30%	10.95%	2.63%	16.66%
49	NORTHEAST UTILITIES	0.440	0.455	22.875	1.60	2.70	1.99%	13.98%	3.32%	23.00%
50	NORTHERN STATES POWER CO.	1.320	1.338	42.750	3.02	3.75	3.13%	5.56%	1.36%	19.22%

Investor Owned Utilities

Constant-Growth DGM Model with Value Line Forecast (CG-VL DGM)+

Source: *CRSP; Value Line*

	Company	[1] Q3 1994 Dividend	[2] Q4 1994 Projected Dividend	[3] Q3 1994 Stock Price	[4] Current EPS	[5] Projected EPS	[6] Quarterly Dividend Yield	[7] Annual Growth Rate	[8] Qtrly Growth Rate	[9] CG-VL DGM ROE
51	OHIO EDISON CO.	0.375	0.380	19.125	1.82	2.25	1.99%	5.45%	1.33%	13.96%
52	OKLAHOMA GAS & ELECTRIC CO.	0.665	0.672	33.292	2.78	3.25	2.02%	3.98%	0.98%	12.54%
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.640	0.644	30.458	3.06	3.40	2.12%	2.67%	0.66%	11.57%
54	PACIFIC GAS & ELECTRIC CO.	0.490	0.496	23.833	2.33	2.85	2.08%	5.17%	1.27%	14.08%
55	PECO ENERGY	0.380	0.385	26.250	2.45	3.00	1.47%	5.19%	1.27%	11.42%
56	PENNSYLVANIA POWER & LIGHT CO.	0.418	0.419	20.542	2.07	2.20	2.04%	1.53%	0.38%	10.04%
57	PORTLAND GENERAL CORP.	0.300	0.303	17.500	1.88	2.15	1.73%	3.41%	0.84%	10.69%
58	POTOMAC ELECTRIC POWER CO.	0.415	0.417	20.042	1.95	2.10	2.08%	1.87%	0.46%	10.57%
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.540	0.543	27.250	2.71	2.95	1.99%	2.14%	0.53%	10.48%
60	PUBLIC SERVICE OF COLORADO	0.500	0.503	27.042	2.48	2.70	1.86%	2.15%	0.53%	9.91%
61	PUGET SOUND POWER & LIGHT	0.460	0.460	19.667	2.00	2.00	2.34%	0.00%	0.00%	9.69%
62	ROCHESTER GAS & ELECTRIC CORP.	0.440	0.446	22.125	2.00	2.50	2.02%	5.74%	1.40%	14.40%
63	SAN DIEGO GAS & ELECTRIC CO.	0.380	0.385	19.625	1.81	2.25	1.96%	5.59%	1.37%	14.01%
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.705	0.708	44.833	3.72	4.00	1.58%	1.83%	0.45%	8.39%
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.250	0.251	13.333	1.57	1.70	1.88%	2.01%	0.50%	9.88%
66	SIERRA PACIFIC RESOURCES	0.280	0.281	19.708	1.67	1.80	1.43%	1.89%	0.47%	7.81%
67	SOUTHERN CO.	0.295	0.299	18.958	1.57	1.90	1.57%	4.89%	1.20%	11.57%
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.413	0.414	27.500	2.45	2.60	1.51%	1.50%	0.37%	7.72%
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.550	0.553	26.500	2.43	2.65	2.09%	2.19%	0.54%	10.94%
70	ST. JOSEPH LIGHT & POWER CO.	0.450	0.456	28.083	1.98	2.45	1.62%	5.47%	1.34%	12.39%
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.253	0.258	19.708	1.30	1.85	1.31%	9.22%	2.23%	14.93%
72	TEXAS UTILITIES CO.	0.770	0.772	33.000	3.19	3.35	2.34%	1.23%	0.31%	11.02%
73	THE DETROIT EDISON CO.	0.515	0.512	26.375	3.34	3.00	1.94%	-2.65%	-0.67%	5.18%
74	THE MONTANA POWER CO.	0.400	0.403	23.417	1.98	2.25	1.72%	3.25%	0.80%	10.48%
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.200	0.207	14.417	1.01	1.70	1.43%	13.90%	3.31%	20.36%
76	UNION ELECTRIC CO.	0.595	0.599	35.083	2.77	3.10	1.71%	2.85%	0.71%	10.01%
77	UNITED ILLUMINATING CO.	0.690	0.697	32.250	3.13	3.65	2.16%	3.92%	0.97%	13.10%
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.430	0.441	28.583	1.85	2.75	1.54%	10.42%	2.51%	17.21%
79	WASHINGTON WATER POWER CO.	0.310	0.314	15.042	1.44	1.75	2.09%	5.00%	1.23%	13.92%
80	WESTERN RESOURCES, INC.	0.495	0.496	28.417	2.76	2.85	1.75%	0.81%	0.20%	8.01%
81	WISCONSIN ENERGY CORP.	0.353	0.357	25.792	1.81	2.25	1.39%	5.59%	1.37%	11.48%
82	WISCONSIN PUBLIC SERVICE CORP.	0.455	0.456	28.833	2.47	2.55	1.58%	0.80%	0.20%	7.31%
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.480	0.486	28.750	2.11	2.60	1.69%	5.36%	1.31%	12.57%

Summary Statistics:		
	Mean =	12.75%
	Median =	11.94%
	Min =	5.18%
	Max =	44.81%

Constant-Growth DGM Model with Value Line Forecast (CG-VL DGM)+

Notes:

+ The CG-VL DGM model is discussed in Stewart Myers and Lynda S. Borucki, "Discounted Cash Flow Estimates of the Cost of Equity Capital--A Case Study," Financial Markets, Institutions & Instruments, V. 3, N. 3, August 1994, pp. 9-45.

[1] The dividend paid to shareholders during Q3 1994.
  Source: CRSP
[2] The dividend projected to be paid to shareholders during Q4 1994.
  Formula: $[1] * (1 + [7])^{1/4}$
[3] The average of the end-of-month stock prices reported for Q3 1994.
  Source: CRSP.
[4] The earnings per share for FY 1993.
  Source: Value Line.
[5] The forecasted long-run earnings per share (given for FY 1997-99).
  Source: Value Line.
[6] The implied quarterly dividend yield.
  Formula: $[2] / [3]$
[7] The projected annual rate of growth of earnings per share.
  Formula: $([5] / [4])^{1/4} - 1$
[8] The projected quarterly rate of growth of earnings per share.
  Formula: $(1 + [7])^{1/4} - 1$
[9] The cost of equity, at an annual rate, as predicted by the CG-VL DGM model.
  Formula: $(1 + ([6] + [8]))^{4} - 1$

Investor Owned Utilities
Constant-Growth DGM Model with Thomson Financial Forecast (CG-IBES DGM)+

Source: *CRSP; Thomson Financial*

	Company	[1] Q3 1994 Dividend	[2] Q4 1994 Projected Dividend	[3] Q3 1994 Stock Price	[4] Qtrly Dividend Yield	[5] IBES 5-Yr EPS Forecast Annual Rate	[6] IBES 5-Yr EPS Forecast Qtrly Rate	[7] CG-IBES DGM ROE
1	ALLEGHENY POWER SYSTEM, INC.	0.410	0.412	21.417	1.92%	1.83%	0.45%	9.85%
2	AMERICAN ELECTRIC POWER, INC.	0.600	0.604	31.125	1.94%	2.41%	0.60%	10.54%
3	ATLANTIC ENERGY, INC.	0.385	0.387	17.625	2.19%	1.75%	0.43%	10.94%
4	BALTIMORE GAS AND ELECTRIC CO.	0.380	0.383	22.958	1.67%	3.63%	0.89%	10.66%
5	BOSTON EDISON CO.	0.440	0.444	25.667	1.73%	3.33%	0.82%	10.60%
6	CAROLINA POWER AND LIGHT	0.425	0.428	26.458	1.62%	2.94%	0.73%	9.71%
7	CENTERIOR ENERGY CORP.	0.200	0.201	9.792	2.05%	1.98%	0.49%	10.57%
8	CENTRAL & SOUTH WEST CORP.	0.425	0.429	22.458	1.91%	3.64%	0.90%	11.72%
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.520	0.523	25.500	2.05%	2.32%	0.58%	10.92%
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.365	0.368	23.000	1.60%	3.13%	0.77%	9.83%
11	CENTRAL MAINE POWER CO.	0.225	0.227	11.500	1.97%	3.00%	0.74%	11.30%
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.355	0.357	13.417	2.66%	2.25%	0.56%	13.51%
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.615	0.619	29.833	2.08%	2.75%	0.68%	11.49%
14	CINCINNATI GAS & ELECTRIC CO.	0.430	0.433	22.417	1.93%	2.95%	0.73%	11.08%
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.500	0.505	27.375	1.85%	4.30%	1.06%	12.13%
16	CMS ENERGY CORP.	0.210	0.213	22.208	0.96%	5.39%	1.32%	9.43%
17	COMMONWEALTH EDISON CO.	0.400	0.406	23.333	1.74%	6.04%	1.48%	13.50%
18	COMMONWEALTH ENERGY SYSTEM	0.750	0.756	39.667	1.90%	3.00%	0.74%	11.01%
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.500	0.503	26.958	1.86%	2.15%	0.53%	9.94%
20	DELMARVA POWER & LIGHT CO.	0.385	0.388	18.875	2.06%	3.03%	0.75%	11.70%
21	DOMINION RESOURCES	0.635	0.640	37.083	1.72%	2.94%	0.73%	10.17%
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.295	0.298	20.042	1.49%	3.97%	0.98%	10.22%
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.420	0.424	29.917	1.42%	3.63%	0.90%	9.57%
24	DUKE POWER CO.	0.490	0.495	38.667	1.28%	3.80%	0.94%	9.16%
25	EASTERN UTILITIES ASSOCIATES	0.385	0.389	24.083	1.61%	4.00%	0.99%	10.81%
26	EMPIRE DISTRICT ELECTRIC	0.320	0.323	16.792	1.92%	4.00%	0.99%	12.16%
27	ENTERGY CORP.	0.450	0.454	24.542	1.85%	3.55%	0.88%	11.36%
28	FLORIDA PROGRESS CORP.	0.495	0.499	28.500	1.75%	3.19%	0.79%	10.55%
29	FPL GROUP, INC.	0.420	0.424	31.792	1.33%	4.05%	1.00%	9.66%
30	GENERAL PUBLIC UTILITIES CORP.	0.450	0.453	25.542	1.77%	2.88%	0.71%	10.32%
31	GREEN MOUNTAIN POWER CORP.	0.530	0.532	25.292	2.10%	1.50%	0.37%	10.28%
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.580	0.586	31.875	1.84%	4.05%	1.00%	11.83%
33	HOUSTON INDUSTRIES, INC.	0.750	0.754	35.042	2.15%	2.05%	0.51%	11.07%
34	IDAHO POWER CO.	0.465	0.469	24.083	1.95%	3.12%	0.77%	11.31%
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.525	0.529	26.958	1.96%	3.02%	0.75%	11.28%
36	INTERSTATE POWER CO.							
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.433	0.436	21.208	2.06%	3.17%	0.78%	11.84%
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.530	0.535	30.042	1.78%	3.59%	0.88%	11.09%
39	KANSAS CITY POWER & LIGHT CO.	0.380	0.383	21.417	1.79%	2.69%	0.66%	10.17%
40	KU ENERGY CO.	0.410	0.413	26.708	1.55%	3.06%	0.76%	9.54%
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.538	0.542	38.042	1.43%	3.57%	0.88%	9.55%
42	LONG ISLAND LIGHTING CO.	0.445	0.447	17.583	2.54%	1.54%	0.38%	12.21%
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.400	0.405	27.375	1.48%	4.64%	1.14%	10.89%
44	MINNESOTA POWER & LIGHT CO.	0.505	0.509	26.583	1.91%	3.02%	0.75%	11.07%
45	NEVADA POWER CO.	0.400	0.403	20.500	1.97%	3.10%	0.77%	11.39%
46	NEW ENGLAND ELECTRIC SYSTEM	0.575	0.579	32.083	1.80%	2.73%	0.67%	10.29%
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.550	0.554	21.417	2.59%	2.81%	0.70%	13.79%
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.360	0.364	28.500	1.28%	4.77%	1.17%	10.17%
49	NORTHEAST UTILITIES	0.440	0.444	22.875	1.94%	3.45%	0.85%	11.64%
50	NORTHERN STATES POWER CO.	1.320	1.332	42.750	3.11%	3.56%	0.88%	16.96%
51	OHIO EDISON CO.	0.375	0.378	19.125	1.97%	2.83%	0.70%	11.14%
52	OKLAHOMA GAS & ELECTRIC CO.	0.665	0.667	33.292	2.00%	1.20%	0.30%	9.53%
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.640	0.644	30.458	2.12%	2.67%	0.66%	11.57%
54	PACIFIC GAS & ELECTRIC CO.	0.490	0.492	23.833	2.07%	1.89%	0.47%	10.53%
55	PECO ENERGY	0.380	0.384	26.250	1.46%	3.82%	0.94%	9.97%

Investor Owned Utilities

Constant-Growth DGM Model with Thomson Financial Forecast (CG-IBES DGM)+

Source: *CRSP; Thomson Financial*

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
	Company	Q3 1994 Dividend	Q4 1994 Projected Dividend	Q3 1994 Stock Price	Qtrly Dividend Yield	IBES 5-Yr EPS Forecast Annual Rate	IBES 5-Yr EPS Forecast Qtrly Rate	CG-IBES DGM ROE
56	PENNSYLVANIA POWER & LIGHT CO.	0.418	0.419	20.542	2.04%	1.47%	0.37%	9.98%
57	PORTLAND GENERAL CORP.	0.300	0.302	17.500	1.73%	2.86%	0.71%	10.09%
58	POTOMAC ELECTRIC POWER CO.	0.415	0.417	20.042	2.08%	1.61%	0.40%	10.29%
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.540	0.544	27.250	2.00%	2.75%	0.68%	11.13%
60	PUBLIC SERVICE OF COLORADO	0.500	0.503	27.042	1.86%	2.13%	0.53%	9.90%
61	PUGET SOUND POWER & LIGHT	0.460	0.462	19.667	2.35%	1.76%	0.44%	11.62%
62	ROCHESTER GAS & ELECTRIC CORP.	0.440	0.442	22.125	2.00%	2.16%	0.54%	10.53%
63	SAN DIEGO GAS & ELECTRIC CO.	0.380	0.382	19.625	1.95%	2.31%	0.57%	10.47%
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.705	0.711	44.833	1.58%	3.17%	0.78%	9.81%
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.250	0.251	13.333	1.88%	1.62%	0.40%	9.46%
66	SIERRA PACIFIC RESOURCES	0.280	0.283	19.708	1.43%	3.83%	0.94%	9.86%
67	SOUTHERN CO.	0.295	0.297	18.958	1.57%	3.40%	0.84%	9.99%
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.413	0.416	27.500	1.51%	3.25%	0.80%	9.59%
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.550	0.552	26.500	2.08%	1.55%	0.39%	10.25%
70	ST. JOSEPH LIGHT & POWER CO.	0.450	0.452	28.083	1.61%	2.05%	0.51%	8.75%
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.253	0.255	19.708	1.30%	4.53%	1.11%	9.99%
72	TEXAS UTILITIES CO.	0.770	0.774	33.000	2.35%	2.23%	0.55%	12.11%
73	THE DETROIT EDISON CO.	0.515	0.517	26.375	1.96%	1.94%	0.48%	10.14%
74	THE MONTANA POWER CO.	0.400	0.404	23.417	1.72%	3.99%	0.98%	11.28%
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.200	0.203	14.417	1.41%	5.50%	1.35%	11.48%
76	UNION ELECTRIC CO.	0.595	0.600	35.083	1.71%	3.20%	0.79%	10.38%
77	UNITED ILLUMINATING CO.	0.690	0.696	32.250	2.16%	3.60%	0.89%	12.75%
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.430	0.436	28.583	1.52%	5.50%	1.35%	11.99%
79	WASHINGTON WATER POWER CO.	0.310	0.312	15.042	2.07%	2.17%	0.54%	10.85%
80	WESTERN RESOURCES, INC.	0.495	0.499	28.417	1.76%	3.20%	0.79%	10.58%
81	WISCONSIN ENERGY CORP.	0.353	0.356	25.792	1.38%	4.38%	1.08%	10.20%
82	WISCONSIN PUBLIC SERVICE CORP.	0.455	0.458	28.833	1.59%	2.62%	0.65%	9.25%
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.480	0.483	28.750	1.68%	2.79%	0.69%	9.82%

Summary Statistics:		
	Mean =	10.81%
	Median =	10.56%
	Min =	8.75%
	Max =	16.96%

Constant-Growth DGM Model with Thomson Financial Forecast (CG-IBES DGM)+

Notes:

+ The CG-IBES DGM model is discussed in Stewart Myers and Lynda S. Borucki, "Discounted Cash Flow Estimates of the Cost of Equity Capital--A Case Study," Financial Markets, Institutions & Instruments, V. 3, N. 3, August 1994, pp. 9-45.

[1] The dividend paid to shareholders during Q3 1994.
Source: CRSP.
[2] The dividend projected to be paid to shareholders during Q4 1994.
*Formula: [1] * (1 + [6])*
[3] The average of the end-of-month stock prices reported for Q3 1994.
Source: CRSP.
[4] The implied quarterly dividend yield.
Formula: [2] / [3]
[5] The forecasted average annual growth in earnings per share over the next 5 years.
Source: Thomson Financial.
[6] The forecasted average growth in earnings per share, at a quarterly rate.
Formula: $(1 + [5])^{1/4} - 1$
[7] The cost of equity, at an annual rate, as predicted by the CG-IBES DGM model.
Formula: $(1 + ([4] + [6]))^{4} - 1$

Investor Owned Utilities
Constant-Growth Sustainable-Growth DGM with Value Line Data (CG-SG DGM)+

Source: CRSP; *Value Line*

	Company	[1] Q3 1994 Dividend	[2] Q4 1994 Projected Dividend	[3] Q3 1994 Stock Price	[4] Book Value Per Share	[5] Projected Annual ROE	[6] Projected Payout-Ratio	[7] Projected Annual Share Growth	[8] Projected Qtrly ROE
1	ALLEGHENY POWER SYSTEM, INC.	0.410	0.413	21.417	17.05	11.50%	80.00%	1.52%	2.76%
2	AMERICAN ELECTRIC POWER, INC.	0.600	0.604	31.125	23.00	12.50%	80.00%	0.47%	2.99%
3	ATLANTIC ENERGY, INC	0.385	0.387	17.625	16.25	11.50%	78.00%	0.69%	2.76%
4	BALTIMORE GAS AND ELECTRIC CO.	0.380	0.383	22.958	18.60	11.00%	75.00%	2.25%	2.64%
5	BOSTON EDISON CO.	0.440	0.443	25.667	20.35	11.50%	79.00%	1.82%	2.76%
6	CAROLINA POWER AND LIGHT	0.425	0.427	26.458	16.75	13.50%	76.00%	-1.55%	3.22%
7	CENTERIOR ENERGY CORP.	0.200	0.202	9.792	12.90	11.00%	61.00%	1.65%	2.64%
8	CENTRAL & SOUTH WEST CORP.	0.425	0.428	22.458	15.80	14.50%	81.00%	0.21%	3.44%
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.520	0.523	25.500	25.00	10.50%	78.00%	1.51%	2.53%
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.365	0.367	23.000	15.20	12.50%	76.00%	-0.43%	2.99%
11	CENTRAL MAINE POWER CO.	0.225	0.226	11.500	17.20	8.00%	69.00%	0.02%	1.94%
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.355	0.356	13.417	15.20	11.00%	82.00%	2.38%	2.64%
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.615	0.618	29.833	26.30	11.50%	82.00%	1.01%	2.76%
14	CINCINNATI GAS & ELECTRIC CO.	0.430	0.434	22.417	17.90	12.50%	72.00%	1.70%	2.99%
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.500	0.503	27.375	19.05	13.00%	81.00%	0.00%	3.10%
16	CMS ENERGY CORP.	0.210	0.214	22.208	12.55	15.50%	55.00%	0.23%	3.67%
17	COMMONWEALTH EDISON CO.	0.400	0.403	23.333	25.45	9.00%	71.00%	0.30%	2.18%
18	COMMONWEALTH ENERGY SYSTEM	0.750	0.756	39.667	34.45	11.00%	73.00%	3.02%	2.64%
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.500	0.504	26.958	22.55	11.50%	75.00%	0.26%	2.76%
20	DELMARVA POWER & LIGHT CO.	0.385	0.386	18.875	15.05	11.50%	88.00%	0.49%	2.76%
21	DOMINION RESOURCES	0.635	0.640	37.083	27.20	11.00%	80.00%	2.28%	2.64%
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.295	0.297	20.042	10.55	14.50%	81.00%	0.83%	3.44%
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.420	0.424	29.917	24.45	11.00%	65.00%	0.04%	2.64%
24	DUKE POWER CO.	0.490	0.495	38.667	22.05	13.00%	68.00%	0.02%	3.10%
25	EASTERN UTILITIES ASSOCIATES	0.385	0.389	24.083	18.40	12.50%	68.00%	1.38%	2.99%
26	EMPIRE DISTRICT ELECTRIC	0.320	0.322	16.792	12.35	12.00%	82.00%	0.96%	2.87%
27	ENTERGY CORP.	0.450	0.453	24.542	29.10	9.50%	76.00%	-0.13%	2.29%
28	FLORIDA PROGRESS CORP.	0.495	0.499	28.500	21.30	11.50%	78.00%	2.10%	2.76%
29	FPL GROUP, INC.	0.420	0.424	31.792	22.50	12.00%	61.00%	-1.63%	2.87%
30	GENERAL PUBLIC UTILITIES CORP.	0.450	0.453	25.542	23.20	11.50%	73.00%	0.01%	2.76%
31	GREEN MOUNTAIN POWER CORP.	0.530	0.533	25.292	21.70	10.50%	89.00%	4.91%	2.53%
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.580	0.584	31.875	23.75	11.00%	85.00%	2.87%	2.64%
33	HOUSTON INDUSTRIES, INC.	0.750	0.756	35.042	26.65	14.50%	78.00%	0.82%	3.44%
34	IDAHO POWER CO.	0.465	0.467	24.083	18.05	11.50%	88.00%	1.07%	2.76%
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.525	0.529	26.958	20.80	12.50%	77.00%	1.72%	2.99%
36	INTERSTATE POWER CO.	0.520	0.523	22.875	20.35	11.00%	87.00%	5.20%	2.64%
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.433	0.435	21.208	17.25	12.00%	80.00%	1.58%	2.87%
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.530	0.534	30.042	21.45	13.00%	76.00%	0.73%	3.10%
39	KANSAS CITY POWER & LIGHT CO.	0.380	0.382	21.417	14.00	13.50%	80.00%	0.00%	3.22%
40	KU ENERGY CO.	0.410	0.413	26.708	16.45	13.00%	73.00%	0.00%	3.10%
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.538	0.542	38.042	23.00	11.50%	78.00%	1.62%	2.76%
42	LONG ISLAND LIGHTING CO.	0.445	0.446	17.583	20.30	10.00%	85.00%	2.99%	2.41%
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.400	0.405	27.375	17.20	14.00%	60.00%	0.00%	3.33%
44	MINNESOTA POWER & LIGHT CO.	0.505	0.508	26.583	18.20	12.00%	80.00%	0.23%	2.87%
45	NEVADA POWER CO.	0.400	0.403	20.500	16.00	10.00%	89.00%	8.35%	2.41%
46	NEW ENGLAND ELECTRIC SYSTEM	0.575	0.579	32.083	25.25	11.50%	76.00%	0.01%	2.76%
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.550	0.553	21.417	23.25	9.50%	77.00%	1.52%	2.29%
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.360	0.365	28.500	17.40	16.00%	61.00%	-1.29%	3.78%
49	NORTHEAST UTILITIES	0.440	0.444	22.875	18.50	13.00%	70.00%	0.46%	3.10%
50	NORTHERN STATES POWER CO.	1.320	1.330	42.750	28.00	12.00%	74.00%	0.04%	2.87%
51	OHIO EDISON CO.	0.375	0.378	19.125	15.10	13.00%	77.00%	0.07%	3.10%
52	OKLAHOMA GAS & ELECTRIC CO.	0.665	0.669	33.292	22.35	13.00%	83.00%	0.09%	3.10%
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.640	0.643	30.458	27.65	11.50%	81.00%	0.13%	2.76%
54	PACIFIC GAS & ELECTRIC CO.	0.490	0.494	23.833	20.65	12.00%	76.00%	1.98%	2.87%
55	PECO ENERGY	0.380	0.384	26.250	19.85	13.50%	67.00%	0.50%	3.22%
56	PENNSYLVANIA POWER & LIGHT CO.	0.418	0.420	20.542	15.95	11.50%	81.00%	2.36%	2.76%

Investor Owned Utilities
Constant-Growth Sustainable-Growth DGM with Value Line Data (CG-SG DGM)+

Source: *CRSP; Value Line*

	Company	[1] Q3 1994 Dividend	[2] Q4 1994 Projected Dividend	[3] Q3 1994 Stock Price	[4] Book Value Per Share	[5] Projected Annual ROE	[6] Projected Payout-Ratio	[7] Projected Annual Share Growth	[8] Projected Qtrly ROE
57	PORTLAND GENERAL CORP.	0.300	0.302	17.500	16.85	11.00%	72.00%	2.59%	2.64%
58	POTOMAC ELECTRIC POWER CO.	0.415	0.417	20.042	16.80	11.50%	85.00%	2.20%	2.76%
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.540	0.543	27.250	21.75	12.00%	79.00%	0.19%	2.87%
60	PUBLIC SERVICE OF COLORADO	0.500	0.504	27.042	20.05	12.00%	82.00%	2.91%	2.87%
61	PUGET SOUND POWER & LIGHT	0.460	0.463	19.667	18.65	9.50%	69.00%	0.26%	2.29%
62	ROCHESTER GAS & ELECTRIC CORP.	0.440	0.443	22.125	19.40	10.50%	80.00%	3.28%	2.53%
63	SAN DIEGO GAS & ELECTRIC CO.	0.380	0.384	19.625	12.65	15.00%	77.00%	0.84%	3.56%
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.705	0.714	44.833	30.20	12.00%	78.00%	4.92%	2.87%
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.250	0.252	13.333	13.75	10.50%	68.00%	0.06%	2.53%
66	SIERRA PACIFIC RESOURCES	0.280	0.282	19.708	17.55	8.50%	74.00%	3.27%	2.06%
67	SOUTHERN CO.	0.295	0.297	18.958	12.50	13.00%	77.00%	0.48%	3.10%
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.413	0.416	27.500	18.75	12.00%	72.00%	0.14%	2.87%
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.550	0.554	26.500	16.95	14.00%	85.00%	1.19%	3.33%
70	ST. JOSEPH LIGHT & POWER CO.	0.450	0.451	28.083	19.80	11.00%	80.00%	-2.66%	2.64%
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.253	0.257	19.708	8.95	16.50%	65.00%	0.93%	3.89%
72	TEXAS UTILITIES CO.	0.770	0.772	33.000	28.90	11.50%	93.00%	0.84%	2.76%
73	THE DETROIT EDISON CO.	0.515	0.518	26.375	22.95	11.50%	76.00%	0.04%	2.76%
74	THE MONTANA POWER CO.	0.400	0.403	23.417	17.95	11.00%	77.00%	3.05%	2.64%
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.200	0.198	14.417	19.15	9.00%	96.00%	17.51%	2.18%
76	UNION ELECTRIC CO.	0.595	0.598	35.083	22.10	13.00%	84.00%	0.00%	3.10%
77	UNITED ILLUMINATING CO.	0.690	0.693	32.250	30.55	11.00%	82.00%	0.39%	2.64%
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.430	0.436	28.583	20.30	11.00%	68.00%	5.32%	2.64%
79	WASHINGTON WATER POWER CO.	0.310	0.312	15.042	12.25	12.00%	80.00%	1.73%	2.87%
80	WESTERN RESOURCES, INC.	0.495	0.498	28.417	23.35	11.00%	77.00%	0.03%	2.64%
81	WISCONSIN ENERGY CORP.	0.353	0.356	25.792	15.85	12.00%	72.00%	2.00%	2.87%
82	WISCONSIN PUBLIC SERVICE CORP.	0.455	0.458	28.833	18.65	12.50%	78.00%	0.31%	2.99%
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.480	0.484	28.750	19.80	12.00%	79.00%	2.04%	2.87%

Investor Owned Utilities

CG-SG DGM +

Source: CRSP; Value Line

	Company	[9] Projected Qtrly Share Growth	[10] Qtrly Dividend Yield	[11] Qtrly Unadjusted Retention Growth Rate	[12] Qtrly Adjusted Retention Growth Rate	[13] Qtrly SV Adjustment	[14] Qtrly Sustainable Growth Rate	[15] Qtrly Cost of Equity	[16] CG-SG DGM ROE
1	ALLEGHENY POWER SYSTEM, INC.	0.38%	1.93%	0.5517%	0.5548%	0.0970%	0.6519%	2.58%	10.72%
2	AMERICAN ELECTRIC POWER, INC.	0.12%	1.94%	0.5977%	0.6013%	0.0410%	0.6423%	2.58%	10.74%
3	ATLANTIC ENERGY, INC.	0.17%	2.20%	0.6069%	0.6106%	0.0145%	0.6252%	2.82%	11.78%
4	BALTIMORE GAS AND ELECTRIC CO.	0.56%	1.67%	0.6608%	0.6652%	0.1309%	0.7961%	2.46%	10.23%
5	BOSTON EDISON CO.	0.45%	1.73%	0.5793%	0.5827%	0.1179%	0.7006%	2.43%	10.07%
6	CAROLINA POWER AND LIGHT	-0.39%	1.62%	0.7720%	0.7780%	-0.2260%	0.5520%	2.17%	8.95%
7	CENTERIOR ENERGY CORP.	0.41%	2.06%	1.0309%	1.0416%	-0.0989%	0.9427%	3.00%	12.57%
8	CENTRAL & SOUTH WEST CORP.	0.05%	1.91%	0.6542%	0.6585%	0.0221%	0.6806%	2.59%	10.75%
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.38%	2.05%	0.5561%	0.5592%	0.0075%	0.5667%	2.62%	10.89%
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	-0.11%	1.60%	0.7172%	0.7224%	-0.0549%	0.6675%	2.27%	9.37%
11	CENTRAL MAINE POWER CO.	0.00%	1.97%	0.6022%	0.6059%	-0.0013%	0.6046%	2.57%	10.70%
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.59%	2.66%	0.4758%	0.4781%	-0.0692%	0.4089%	3.07%	12.84%
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.25%	2.07%	0.4966%	0.4990%	0.0337%	0.5327%	2.61%	10.83%
14	CINCINNATI GAS & ELECTRIC CO.	0.42%	1.94%	0.8367%	0.8438%	0.1065%	0.9503%	2.89%	12.06%
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.00%	1.84%	0.5895%	0.5930%	0.0000%	0.5930%	2.43%	10.08%
16	CMS ENERGY CORP.	0.06%	0.96%	1.6507%	1.6784%	0.0450%	1.7234%	2.69%	11.18%
17	COMMONWEALTH EDISON CO.	0.07%	1.73%	0.6316%	0.6356%	-0.0062%	0.6294%	2.35%	9.76%
18	COMMONWEALTH ENERGY SYSTEM	0.75%	1.91%	0.7137%	0.7188%	0.1129%	0.8317%	2.74%	11.41%
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.06%	1.87%	0.6897%	0.6945%	0.0126%	0.7071%	2.57%	10.70%
20	DELMARVA POWER & LIGHT CO.	0.12%	2.05%	0.3310%	0.3321%	0.0313%	0.3634%	2.41%	10.00%
21	DOMINION RESOURCES	0.57%	1.72%	0.5287%	0.5315%	0.2056%	0.7370%	2.46%	10.22%
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.21%	1.48%	0.6542%	0.6585%	0.1867%	0.8451%	2.33%	9.65%
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.01%	1.42%	0.9252%	0.9338%	0.0024%	0.9362%	2.35%	9.75%
24	DUKE POWER CO.	0.00%	1.28%	0.9928%	1.0028%	0.0032%	1.0060%	2.29%	9.46%
25	EASTERN UTILITIES ASSOCIATES	0.34%	1.62%	0.9563%	0.9655%	0.1058%	1.0713%	2.69%	11.19%
26	EMPIRE DISTRICT ELECTRIC	0.24%	1.92%	0.5173%	0.5200%	0.0862%	0.6062%	2.52%	10.48%
27	ENTERGY CORP.	-0.03%	1.84%	0.5508%	0.5538%	0.0052%	0.5590%	2.40%	9.96%
28	FLORIDA PROGRESS CORP.	0.52%	1.75%	0.6069%	0.6106%	0.1761%	0.7868%	2.54%	10.54%
29	FPL GROUP, INC.	-0.41%	1.33%	1.1208%	1.1335%	-0.1690%	0.9645%	2.30%	9.52%
30	GENERAL PUBLIC UTILITIES CORP.	0.00%	1.78%	0.7449%	0.7504%	0.0002%	0.7506%	2.53%	10.49%
31	GREEN MOUNTAIN POWER CORP.	1.21%	2.11%	0.2780%	0.2788%	0.1996%	0.4784%	2.58%	10.74%
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.71%	1.83%	0.3965%	0.3981%	0.2431%	0.6411%	2.47%	10.26%
33	HOUSTON INDUSTRIES, INC.	0.20%	2.16%	0.7575%	0.7633%	0.0644%	0.8276%	2.99%	12.49%
34	IDAHO POWER CO.	0.27%	1.94%	0.3310%	0.3321%	0.0889%	0.4210%	2.36%	9.78%
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.43%	1.96%	0.6873%	0.6921%	0.1266%	0.8187%	2.78%	11.60%
36	INTERSTATE POWER CO.	1.27%	2.28%	0.3436%	0.3448%	0.1582%	0.5030%	2.79%	11.63%
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.39%	2.05%	0.5747%	0.5781%	0.0901%	0.6682%	2.72%	11.34%
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.18%	1.78%	0.7446%	0.7502%	0.0727%	0.8229%	2.60%	10.82%
39	KANSAS CITY POWER & LIGHT CO.	0.00%	1.79%	0.6433%	0.6475%	0.0000%	0.6475%	2.43%	10.09%
40	KU ENERGY CO.	0.00%	1.55%	0.8377%	0.8448%	0.0000%	0.8448%	2.39%	9.92%
41	LG&E ENERGY CORP (LOUISVILLE GAS & ELECTRIC CO.)	0.40%	1.43%	0.6069%	0.6106%	0.2635%	0.8741%	2.30%	9.52%
42	LONG ISLAND LIGHTING CO.	0.74%	2.54%	0.3617%	0.3630%	-0.0991%	0.2639%	2.80%	11.69%
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.00%	1.48%	1.3320%	1.3500%	0.0000%	1.3500%	2.83%	11.81%
44	MINNESOTA POWER & LIGHT CO.	0.06%	1.91%	0.5747%	0.5781%	0.0266%	0.6047%	2.52%	10.45%
45	NEVADA POWER CO.	2.02%	1.97%	0.2653%	0.2660%	0.5693%	0.8352%	2.80%	11.69%
46	NEW ENGLAND ELECTRIC SYSTEM	0.00%	1.80%	0.6621%	0.6665%	0.0008%	0.6673%	2.47%	10.26%
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.38%	2.58%	0.5278%	0.5306%	-0.0299%	0.5008%	3.08%	12.91%
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	-0.32%	1.28%	1.4743%	1.4963%	-0.2066%	1.2897%	2.57%	10.68%
49	NORTHEAST UTILITIES	0.12%	1.94%	0.9308%	0.9395%	0.0273%	0.9669%	2.91%	12.15%
50	NORTHERN STATES POWER CO.	0.01%	3.11%	0.7472%	0.7528%	0.0059%	0.7587%	3.87%	16.40%
51	OHIO EDISON CO.	0.02%	1.97%	0.7136%	0.7187%	0.0047%	0.7234%	2.70%	11.24%
52	OKLAHOMA GAS & ELECTRIC CO.	0.02%	2.01%	0.5274%	0.5302%	0.0114%	0.5416%	2.55%	10.60%
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.03%	2.11%	0.5242%	0.5269%	0.0033%	0.5302%	2.64%	11.00%
54	PACIFIC GAS & ELECTRIC CO.	0.49%	2.07%	0.6897%	0.6945%	0.0756%	0.7701%	2.84%	11.86%
55	PECO ENERGY	0.13%	1.46%	1.0614%	1.0728%	0.0404%	1.1132%	2.58%	10.71%
56	PENNSYLVANIA POWER & LIGHT CO.	0.58%	2.05%	0.5242%	0.5269%	0.1683%	0.6952%	2.74%	11.43%

Investor Owned Utilities

CG-SG DGM +

Source: CRSP; Value Line

	Company	[9] Projected Qtrly Share Growth	[10] Qtrly Dividend Yield	[11] Qtrly Unadjusted Retention Growth Rate	[12] Qtrly Adjusted Retention Growth Rate	[13] Qtrly SV Adjustment	[14] Qtrly Sustainable Growth Rate	[15] Qtrly Cost of Equity	[16] CG-SG DGM ROE
57	PORTLAND GENERAL CORP.	0.64%	1.73%	0.7401%	0.7457%	0.0247%	0.7703%	2.50%	10.37%
58	POTOMAC ELECTRIC POWER CO.	0.54%	2.08%	0.4138%	0.4155%	0.1051%	0.5207%	2.60%	10.82%
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.05%	1.99%	0.6035%	0.6071%	0.0117%	0.6188%	2.61%	10.87%
60	PUBLIC SERVICE OF COLORADO	0.72%	1.86%	0.5173%	0.5200%	0.2506%	0.7706%	2.63%	10.96%
61	PUGET SOUND POWER & LIGHT	0.07%	2.36%	0.7114%	0.7165%	0.0036%	0.7201%	3.08%	12.88%
62	ROCHESTER GAS & ELECTRIC CORP.	0.81%	2.00%	0.5055%	0.5081%	0.1139%	0.6220%	2.62%	10.91%
63	SAN DIEGO GAS & ELECTRIC CO.	0.21%	1.95%	0.8178%	0.8246%	0.1159%	0.9404%	2.89%	12.09%
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	1.21%	1.59%	0.6322%	0.6362%	0.5856%	1.2219%	2.81%	11.74%
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.01%	1.89%	0.8088%	0.8154%	-0.0004%	0.8150%	2.71%	11.27%
66	SIERRA PACIFIC RESOURCES	0.81%	1.43%	0.5357%	0.5386%	0.0995%	0.6381%	2.07%	8.53%
67	SOUTHERN CO.	0.12%	1.57%	0.7136%	0.7187%	0.0615%	0.7802%	2.35%	9.73%
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.04%	1.51%	0.8046%	0.8112%	0.0167%	0.8278%	2.34%	9.69%
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.30%	2.09%	0.4995%	0.5020%	0.1666%	0.6686%	2.76%	11.50%
70	ST. JOSEPH LIGHT & POWER CO.	-0.67%	1.61%	0.5287%	0.5315%	-0.2811%	0.2504%	1.86%	7.64%
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.23%	1.30%	1.3621%	1.3810%	0.2797%	1.6606%	2.96%	12.39%
72	TEXAS UTILITIES CO.	0.21%	2.34%	0.1931%	0.1935%	0.0298%	0.2232%	2.56%	10.65%
73	THE DETROIT EDISON CO.	0.01%	1.97%	0.6621%	0.6665%	0.0016%	0.6681%	2.63%	10.96%
74	THE MONTANA POWER CO.	0.75%	1.72%	0.6080%	0.6117%	0.2295%	0.8412%	2.56%	10.66%
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	4.12%	1.37%	0.0871%	0.0872%	-1.0172%	-0.9300%	0.44%	1.79%
76	UNION ELECTRIC CO.	0.00%	1.70%	0.4964%	0.4989%	-0.0007%	0.4982%	2.20%	9.11%
77	UNITED ILLUMINATING CO.	0.10%	2.15%	0.4758%	0.4781%	0.0054%	0.4835%	2.63%	10.96%
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	1.30%	1.53%	0.8459%	0.8531%	0.5321%	1.3852%	2.91%	12.16%
79	WASHINGTON WATER POWER CO.	0.43%	2.07%	0.5747%	0.5781%	0.0978%	0.6758%	2.75%	11.47%
80	WESTERN RESOURCES, INC.	0.01%	1.75%	0.6080%	0.6117%	0.0018%	0.6134%	2.37%	9.81%
81	WISCONSIN ENERGY CORP.	0.50%	1.38%	0.8046%	0.8112%	0.3112%	1.1224%	2.50%	10.40%
82	WISCONSIN PUBLIC SERVICE CORP.	0.08%	1.59%	0.6574%	0.6618%	0.0426%	0.7044%	2.29%	9.49%
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.51%	1.68%	0.6035%	0.6071%	0.2287%	0.8359%	2.52%	10.46%

Summary Statistics:		
	Mean =	10.71%
	Median =	10.72%
	Min =	1.79%
	Max =	16.40%

Investor Owned Utilities

Constant-Growth Sustainable-Growth DGM Model with Value Line Forecast (CG-SG DGM)+

Notes:

+ The CG-SG DGM model is discussed in Stewart Myers and Lynda S. Borucki, "Discounted Cash Flow Estimates of the Cost of Equity Capital--A Case Study," Financial Markets, Institutions & Instruments, V. 3, N. 3, August 1994, pp. 9-45.

[1] The dividend paid to shareholders during Q3 1994.
Source: CRSP.
[2] The dividend projected to be paid to shareholders during Q4 1994.
*Formula: [1] * (1 + [14])*
[3] The average of the end-of-month stock prices reported for Q3 1994.
Source: CRSP.
[4] The predicted FY 1994 book value per share. (Uses forecast figures.)
Source: Value Line.
[5] The projected annual rate of return on equity for FY 1997-99.
Source: Value Line.
[6] The projected payout-to-earnings ratio for FY 1997-99.
Source: Value Line.
[7] The projected average annual growth rate of common shares outstanding for the FY 1993 to FY 1997 period.
Source: Value Line.
[8] The projected quarterly rate of return on equity for FY 1997.
Formula: $(1 + [5])^{1/4} - 1$
[9] The projected quarterly growth rate of common shares outstanding for the FY 1993 to FY 1997 period.
Formula: $(1 + [7])^{1/4} - 1$
[10] The implied quarterly dividend yield.
Formula: [2] / [3]
[11] The quarterly unadjusted retention growth rate (projected quarterly return on equity times the retention ratio).
*Formula: [8] * (1 - [6])*
[12] The quarterly adjusted retention growth rate. (The projected quarterly return on equity is divided by one minus the quarterly unadjusted retention growth rate. This quantity is then multiplied by the retention ratio.) This adjustment methodology is recommended by Myers and Borucki, p. 38, fn.2.
*Formula: ([8] / (1 - [11])) * (1 - [6])*
[13] The quarterly SV adjustment, as explained by Myers and Borucki, p. 40.
*Formula: (([9] * [3]) / [4]) * (([3] - [4]) / [3])*
[14] The quarterly sustainable growth rate of earnings per share.
Formula: [12] + [13]
[15] The projected quarterly cost of equity.
Formula: [10] + [14]
[16] The cost of equity, at an annual rate, as predicted by the CG-SG DGM model.
Formula: $(1 + [15])^{4} - 1$

Investor Owned Utilities

Variable-Growth DGM Model with Thomson Financial Qtrs. 9 to 20 Earnings Growth Rate (VG-Q920 DGM)$^+$

Source: *CRSP; Thomson Financial*

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
								Nominal Projected Dividends		
	Company	Q3 1994 Stock Price	Thomson Financial 1994 EPS Growth Forecast	Thomson Financial 1995 EPS Growth Forecast	Thomson Financial 1996 -1998 EPS Growth Forecast	Q3 1994 Dividend (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)
1	ALLEGHENY POWER SYSTEM, INC.	21.417	1.53%	3.07%	1.52%	0.4100	0.4116	0.4147	0.4178	0.4210
2	AMERICAN ELECTRIC POWER, INC.	31.125	4.12%	0.57%	2.47%	0.6000	0.6061	0.6069	0.6078	0.6087
3	ATLANTIC ENERGY, INC.	17.625	-1.30%	-1.69%	3.97%	0.3850	0.3837	0.3821	0.3805	0.3789
4	BALTIMORE GAS AND ELECTRIC CO.	22.958	3.87%	3.02%	3.75%	0.3800	0.3836	0.3865	0.3894	0.3923
5	BOSTON EDISON CO.	25.667	20.41%	3.44%	-1.84%	0.4400	0.4609	0.4648	0.4688	0.4728
6	CAROLINA POWER AND LIGHT	26.458	8.42%	4.40%	0.70%	0.4250	0.4337	0.4384	0.4431	0.4479
7	CENTERIOR ENERGY CORP.	9.792	6.77%	7.11%	-1.21%	0.2000	0.2033	0.2068	0.2104	0.2141
8	CENTRAL & SOUTH WEST CORP.	22.458	7.27%	1.65%	3.13%	0.4250	0.4325	0.4343	0.4361	0.4379
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	25.500	-2.18%	1.47%	4.15%	0.5200	0.5171	0.5190	0.5209	0.5228
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	23.000	-14.74%	0.66%	10.77%	0.3650	0.3507	0.3513	0.3519	0.3525
11	CENTRAL MAINE POWER CO.	11.500	-30.35%	2.70%	17.46%	0.2250	0.2056	0.2069	0.2083	0.2097
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	13.417	-11.99%	5.54%	6.36%	0.3550	0.3438	0.3485	0.3532	0.3580
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	29.833	6.87%	1.75%	1.74%	0.6150	0.6253	0.6280	0.6307	0.6335
14	CINCINNATI GAS & ELECTRIC CO.	22.417	1.37%	1.69%	3.91%	0.4300	0.4315	0.4333	0.4351	0.4369
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	27.375	-3.95%	0.28%	8.62%	0.5000	0.4950	0.4953	0.4957	0.4960
16	CMS ENERGY CORP.	22.208	11.11%	6.54%	3.18%	0.2100	0.2156	0.2190	0.2225	0.2261
17	COMMONWEALTH EDISON CO.	23.333	0.67%	34.17%	-0.25%	0.4000	0.4007	0.4312	0.4641	0.4995
18	COMMONWEALTH ENERGY SYSTEM	39.667	-1.03%	-2.02%	6.13%	0.7500	0.7481	0.7442	0.7405	0.7367
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	26.958	6.21%	-3.97%	2.93%	0.5000	0.5076	0.5025	0.4974	0.4924
20	DELMARVA POWER & LIGHT CO.	18.875	-2.01%	-1.47%	6.33%	0.3850	0.3831	0.3816	0.3802	0.3788
21	DOMINION RESOURCES	37.083	1.67%	2.45%	3.53%	0.6350	0.6376	0.6415	0.6454	0.6493
22	DPL INC. (DAYTON POWER & LIGHT CO.)	20.042	10.05%	3.66%	2.12%	0.2950	0.3021	0.3049	0.3076	0.3104
23	DQE, INC. (DUQUESNE LIGHT CO.)	29.917	6.64%	3.32%	2.75%	0.4200	0.4268	0.4303	0.4338	0.4374
24	DUKE POWER CO.	38.667	5.30%	2.33%	3.79%	0.4900	0.4964	0.4992	0.5021	0.5050
25	EASTERN UTILITIES ASSOCIATES	24.083	-1.87%	1.43%	6.92%	0.3850	0.3832	0.3846	0.3859	0.3873
26	EMPIRE DISTRICT ELECTRIC	16.792	7.76%	9.00%	1.18%	0.3200	0.3260	0.3331	0.3404	0.3478
27	ENTERGY CORP.	24.542	-10.43%	3.72%	8.62%	0.4500	0.4378	0.4418	0.4459	0.4499
28	FLORIDA PROGRESS CORP.	28.500	6.35%	3.07%	2.20%	0.4950	0.5027	0.5065	0.5103	0.5142
29	FPL GROUP, INC.	31.792	4.85%	4.05%	3.79%	0.4200	0.4250	0.4292	0.4335	0.4379
30	GENERAL PUBLIC UTILITIES CORP.	25.542	6.34%	1.90%	2.08%	0.4500	0.4570	0.4591	0.4613	0.4635
31	GREEN MOUNTAIN POWER CORP.	25.292	-0.11%	1.71%	1.97%	0.5300	0.5298	0.5321	0,5344	0.5366
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	31.875	6.17%	7.55%	2.22%	0.5800	0.5888	0.5996	0.6106	0.6218
33	HOUSTON INDUSTRIES, INC.	35.042	3.12%	-0.59%	2.59%	0.7500	0.7558	0.7547	0.7535	0.7524
34	IDAHO POWER CO.	24.083	-5.08%	9.61%	3.87%	0.4650	0.4590	0.4696	0.4805	0.4917
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	26.958	0.66%	2.84%	3.88%	0.5250	0.5259	0.5296	0.5333	0.5370
36	INTERSTATE POWER CO.									
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	21.208	4.45%	4.33%	2.36%	0.4325	0.4372	0.4419	0.4466	0.4513
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	30.042	0.85%	2.37%	4.92%	0.5300	0.5311	0.5343	0.5374	0.5405
39	KANSAS CITY POWER & LIGHT CO.	21.417	9.60%	3.27%	0.29%	0.3800	0.3888	0.3919	0.3951	0.3983
40	KU ENERGY CO.	26.708	-2.11%	2.95%	4.88%	0.4100	0.4078	0.4108	0.4138	0.4168
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	38.042	5.02%	4.00%	2.94%	0.5375	0.5441	0.5495	0.5549	0.5604
42	LONG ISLAND LIGHTING CO.	17.583	-3.43%	1.09%	3.40%	0.4450	0.4411	0.4423	0.4435	0.4447
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	27.375	3.89%	4.32%	5.00%	0.4000	0.4038	0.4081	0.4125	0.4169
44	MINNESOTA POWER & LIGHT CO.	26.583	-1.79%	10.12%	2.38%	0.5050	0.5027	0.5150	0.5275	0.5404
45	NEVADA POWER CO.	20.500	0.99%	1.59%	4.33%	0.4000	0.4010	0.4026	0.4041	0.4057
46	NEW ENGLAND ELECTRIC SYSTEM	32.083	9.42%	2.75%	0.57%	0.5750	0.5881	0.5921	0.5961	0.6002
47	NEW YORK STATE ELECTRIC & GAS CORP.	21.417	-2.15%	4.09%	4.09%	0.5500	0.5470	0.5525	0.5581	0.5637
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	28.500	6.03%	3.69%	4.72%	0.3600	0.3653	0.3686	0.3720	0.3754
49	NORTHEAST UTILITIES	22.875	18.87%	0.82%	-0.38%	0.4400	0.4594	0.4604	0.4613	0.4623
50	NORTHERN STATES POWER CO.	42.750	14.24%	1.71%	0.83%	1.3200	1.3647	1.3705	1.3763	1.3821
51	OHIO EDISON CO.	19.125	1.15%	3.07%	3.32%	0.3750	0.3761	0.3789	0.3818	0.3847
52	OKLAHOMA GAS & ELECTRIC CO.	33.292	-5.87%	2.10%	3.36%	0.6650	0.6550	0.6584	0.6619	0.6653
53	ORANGE & ROCKLAND INDUSTRIES, INC.	30.458	2.78%	4.17%	2.13%	0.6400	0.6444	0.6510	0.6577	0.6645

Investor Owned Utilities

Variable-Growth DGM Model with Thomson Financial Qtrs. 9 to 20 Earnings Growth Rate (VG-Q920 DGM)+

Source: *CRSP; Thomson Financial*

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
							Nominal Projected Dividends			
	Company	Q3 1994 Stock Price	Thomson Financial 1994 EPS Growth Forecast	Thomson Financial 1995 EPS Growth Forecast	Thomson Financial 1996 -1998 EPS Growth Forecast	Q3 1994 Dividend (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)
54	PACIFIC GAS & ELECTRIC CO.	23.833	7.57%	6.99%	-1.55%	0.4900	0.4990	0.5075	0.5162	0.5250
55	PECO ENERGY	26.250	3.05%	3.66%	4.14%	0.3800	0.3829	0.3863	0.3898	0.3933
56	PENNSYLVANIA POWER & LIGHT CO.	20.542	-3.02%	-1.25%	3.95%	0.4175	0.4143	0.4130	0.4117	0.4104
57	PORTLAND GENERAL CORP.	17.500	-7.05%	-1.87%	8.07%	0.3000	0.2946	0.2932	0.2918	0.2904
58	POTOMAC ELECTRIC POWER CO.	20.042	-2.95%	0.60%	3.52%	0.4150	0.4119	0.4125	0.4131	0.4138
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	27.250	9.93%	2.80%	0.44%	0.5400	0.5529	0.5568	0.5606	0.5645
60	PUBLIC SERVICE OF COLORADO	27.042	-1.30%	5.20%	2.29%	0.5000	0.4984	0.5047	0.5112	0.5177
61	PUGET SOUND POWER & LIGHT	19.667	-8.11%	3.54%	4.67%	0.4600	0.4504	0.4543	0.4583	0.4623
62	ROCHESTER GAS & ELECTRIC CORP.	22.125	13.25%	1.61%	-1.11%	0.4400	0.4539	0.4557	0.4575	0.4594
63	SAN DIEGO GAS & ELECTRIC CO.	19.625	2.32%	2.73%	2.17%	0.3800	0.3822	0.3848	0.3874	0.3900
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	44.833	-2.05%	1.73%	5.46%	0.7050	0.7014	0.7044	0.7074	0.7105
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	13.333	-2.74%	2.56%	2.80%	0.2500	0.2483	0.2498	0.2514	0.2530
66	SIERRA PACIFIC RESOURCES	19.708	4.36%	4.17%	3.55%	0.2800	0.2830	0.2859	0.2888	0.2918
67	SOUTHERN CO.	18.958	2.60%	3.80%	3.53%	0.2950	0.2969	0.2997	0.3025	0.3053
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	27.500	-1.72%	1.01%	5.73%	0.4125	0.4107	0.4118	0.4128	0.4138
69	SOUTHWESTERN PUBLIC SERVICE CO.	26.500	-5.14%	2.13%	3.69%	0.5500	0.5428	0.5457	0.5485	0.5514
70	ST. JOSEPH LIGHT & POWER CO.	28.083	-6.57%	12.16%	1.84%	0.4500	0.4424	0.4553	0.4686	0.4822
71	TECO ENERGY INC. (TAMPA ELECTRIC)	19.708	6.14%	4.22%	4.10%	0.2525	0.2563	0.2590	0.2616	0.2644
72	TEXAS UTILITIES CO.	33.000	-11.30%	9.22%	4.84%	0.7700	0.7473	0.7639	0.7810	0.7984
73	THE DETROIT EDISON CO.	26.375	-22.08%	3.13%	11.06%	0.5150	0.4839	0.4876	0.4914	0.4952
74	THE MONTANA POWER CO.	23.417	2.77%	2.93%	4.76%	0.4000	0.4027	0.4057	0.4086	0.4116
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	14.417	-3.79%	58.93%	-5.10%	0.2000	0.1981	0.2224	0.2497	0.2804
76	UNION ELECTRIC CO.	35.083	7.79%	-1.59%	3.33%	0.5950	0.6063	0.6039	0.6014	0.5990
77	UNITED ILLUMINATING CO.	32.250	3.73%	4.77%	3.17%	0.6900	0.6963	0.7045	0.7128	0.7211
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	28.583	0.20%	5.96%	7.17%	0.4300	0.4302	0.4365	0.4428	0.4493
79	WASHINGTON WATER POWER CO.	15.042	-6.33%	4.61%	4.34%	0.3100	0.3050	0.3084	0.3119	0.3155
80	WESTERN RESOURCES, INC.	28.417	-7.73%	3.33%	7.08%	0.4950	0.4851	0.4891	0.4932	0.4972
81	WISCONSIN ENERGY CORP.	25.792	8.77%	4.79%	2.82%	0.3525	0.3600	0.3642	0.3685	0.3728
82	WISCONSIN PUBLIC SERVICE CORP.	28.833	-4.08%	3.38%	4.70%	0.4550	0.4503	0.4540	0.4578	0.4616
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	28.750	8.46%	1.58%	1.36%	0.4800	0.4898	0.4918	0.4937	0.4956

Investor Owned Utilities

VG-Q920 DGM^{+}

Source: CRSP; Thomson Financial

	Company	[10] Q4 1995 (DIV6)	[11] Nominal Projected Dividends Q1 1996 (DIV7)	[12] Q2 1996 (DIVT)	[13] Q3 1996 (DIVT+1)	[14] Long-term Quarterly Growth Rate (GTERM)	[15] Terminal Price (PTERM)	[16] Quarterly Cost of Equity	[17] VG-Q920 DGM ROE	[18] Discoun Q3 1994 (DIV1)
1	ALLEGHENY POWER SYSTEM, INC.	0.4242	0.4258	0.4274	0.4290	0.3777%	21.5839	2.37%	9.80%	0.4100
2	AMERICAN ELECTRIC POWER, INC.	0.6095	0.6132	0.6170	0.6208	0.6108%	31.8262	2.56%	10.65%	0.6000
3	ATLANTIC ENERGY, INC.	0.3773	0.3810	0.3847	0.3884	0.9782%	18.4030	3.09%	12.94%	0.3850
4	BALTIMORE GAS AND ELECTRIC CO.	0.3952	0.3989	0.4025	0.4063	0.9250%	24.0745	2.61%	10.87%	0.3800
5	BOSTON EDISON CO.	0.4768	0.4746	0.4724	0.4702	-0.4642%	24.4765	1.46%	5.96%	0.4400
6	CAROLINA POWER AND LIGHT	0.4527	0.4535	0.4543	0.4551	0.1745%	26.3920	1.90%	7.81%	0.4250
7	CENTERIOR ENERGY CORP.	0.2178	0.2171	0.2164	0.2158	-0.3033%	9.4304	1.98%	8.18%	0.2000
8	CENTRAL & SOUTH WEST CORP.	0.4397	0.4431	0.4465	0.4499	0.7733%	23.2381	2.71%	11.29%	0.4250
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.5248	0.5301	0.5355	0.5410	1.0228%	26.7903	3.04%	12.74%	0.5200
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.3530	0.3622	0.3716	0.3812	2.5898%	26.9816	4.00%	17.00%	0.3650
11	CENTRAL MAINE POWER CO.	0.2111	0.2198	0.2288	0.2382	4.1050%	14.8639	5.71%	24.86%	0.2250
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.3629	0.3685	0.3743	0.3801	1.5540%	14.5437	4.17%	17.74%	0.3550
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.6362	0.6390	0.6418	0.6445	0.4333%	30.1163	2.57%	10.70%	0.6150
14	CINCINNATI GAS & ELECTRIC CO	0.4388	0.4430	0.4472	0.4516	0.9633%	23.4893	2.89%	12.05%	0.4300
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.4964	0.5067	0.5173	0.5281	2.0886%	30.9563	3.79%	16.06%	0.5000
16	CMS ENERGY CORP.	0.2297	0.2315	0.2333	0.2351	0.7852%	23.2542	1.80%	7.38%	0.2100
17	COMMONWEALTH EDISON CO.	0.5376	0.5373	0.5369	0.5366	-0.0627%	23.1739	2.25%	9.32%	0.4000
18	COMMONWEALTH ENERGY SYSTEM	0.7329	0.7439	0.7551	0.7664	1.4993%	43.0392	3.28%	13.78%	0.7500
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.4874	0.4910	0.4945	0.4981	0.7245%	27.7445	2.52%	10.47%	0.5000
20	DELMARVA POWER & LIGHT CO.	0.3774	0.3833	0.3892	0.3952	1.5470%	20.5141	3.47%	14.64%	0.3850
21	DOMINION RESOURCES	0.6532	0.6589	0.6647	0.6705	0.8720%	38.7145	2.60%	10.83%	0.6350
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.3132	0.3149	0.3165	0.3182	0.5246%	20.4949	2.08%	8.57%	0.2950
23	DQE, INC. (DUQUESNE LIGHT CO)	0.4410	0.4440	0.4470	0.4500	0.6800%	30.9365	2.13%	8.82%	0.4200
24	DUKE POWER CO.	0.5080	0.5127	0.5175	0.5223	0.9355%	40.7298	2.22%	9.17%	0.4900
25	EASTERN UTILITIES ASSOCIATES	0.3887	0.3952	0.4019	0.4087	1.6872%	26.5905	3.22%	13.53%	0.3850
26	EMPIRE DISTRICT ELECTRIC	0.3554	0.3564	0.3575	0.3585	0.2938%	16.8746	2.42%	10.03%	0.3200
27	ENTERGY CORP.	0.4541	0.4636	0.4732	0.4831	2.0880%	27.7879	3.83%	16.21%	0.4500
28	FLORIDA PROGRESS CORP.	0.5181	0.5209	0.5238	0.5266	0.5449%	29.1016	2.35%	9.76%	0.4950
29	FPL GROUP, INC.	0.4422	0.4464	0.4505	0.4547	0.9339%	33.4836	2.29%	9.49%	0.4200
30	GENERAL PUBLIC UTILITIES CORP.	0.4656	0.4680	0.4705	0.4729	0.5154%	26.0091	2.33%	9.67%	0.4500
31	GREEN MOUNTAIN POWER CORP.	0.5389	0.5415	0.5442	0.5469	0.4900%	25.6202	2.62%	10.92%	0.5300
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.6332	0.6367	0.6402	0.6437	0.5500%	32.5966	2.52%	10.49%	0.5800
33	HOUSTON INDUSTRIES, INC.	0.7513	0.7561	0.7610	0.7658	0.6413%	35.8027	2.78%	11.59%	0.7500
34	IDAHO POWER CO.	0.5031	0.5079	0.5127	0.5176	0.9529%	25.3048	3.00%	12.54%	0.4650
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.5408	0.5460	0.5512	0.5565	0.9559%	28.2395	2.93%	12.23%	0.5250
36	INTERSTATE POWER CO.									
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.4562	0.4588	0.4615	0.4642	0.5850%	21.6625	2.73%	11.37%	0.4325
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.5437	0.5503	0.5570	0.5637	1.2089%	32.0679	2.97%	12.41%	0.5300
39	KANSAS CITY POWER & LIGHT CO.	0.4015	0.4018	0.4021	0.4024	0.0724%	21.1714	1.97%	8.13%	0.3800
40	KU ENERGY CO.	0.4198	0.4249	0.4300	0.4351	1.1986%	28.5653	2.72%	11.34%	0.4100
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.5659	0.5700	0.5741	0.5783	0.7281%	39.4721	2.19%	9.07%	0.5375
42	LONG ISLAND LIGHTING CO.	0.4459	0.4497	0.4535	0.4573	0.8395%	18.1466	3.36%	14.13%	0.4450
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.4213	0.4265	0.4317	0.4370	1.2263%	29.3708	2.71%	11.31%	0.4000
44	MINNESOTA POWER & LIGHT CO	0.5536	0.5568	0.5601	0.5634	0.5893%	27.2677	2.66%	11.05%	0.5050
45	NEVADA POWER CO.	0.4073	0.4117	0.4161	0.4205	1.0649%	21.6207	3.01%	12.59%	0.4000
46	NEW ENGLAND ELECTRIC SYSTEM	0.6043	0.6052	0.6060	0.6069	0.1434%	31.8571	2.05%	8.45%	0.5750
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.5694	0.5751	0.5809	0.5868	1.0072%	22.3830	3.63%	15.32%	0.5500
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.3788	0.3832	0.3876	0.3921	1.1593%	30.4953	2.45%	10.15%	0.3600
49	NORTHEAST UTILITIES	0.4632	0.4628	0.4623	0.4619	-0.0950%	22.2993	1.98%	8.14%	0.4400
50	NORTHERN STATES POWER CO.	1.3880	1.3908	1.3937	1.3966	0.2072%	42.0636	3.53%	14.87%	1.3200
51	OHIO EDISON CO.	0.3876	0.3908	0.3940	0.3972	0.8202%	19.8510	2.82%	11.77%	0.3750
52	OKLAHOMA GAS & ELECTRIC CO	0.6688	0.6744	0.6800	0.6856	0.8308%	34.5518	2.82%	11.74%	0.6650
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.6713	0.6748	0.6784	0.6820	0.5289%	30.9718	2.73%	11.38%	0.6400

Investor Owned Utilities

VG-Q920 DGM+

Source: CRSP; Thomson Financial

		[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
		Nominal Projected Dividends				Long-term Quarterly	Terminal Price	Quarterly Cost	VG-Q920	Discoun
	Company	Q4 1995 (DIV6)	Q1 1996 (DIV7)	Q2 1996 (DIVT)	Q3 1996 (DIVT+1)	Growth Rate (GTERM)	(PTERM)	of Equity	DGM ROE	Q3 1994 (DIV1)
54	PACIFIC GAS & ELECTRIC CO.	0.5339	0.5318	0.5298	0.5277	-0.3908%	22.8140	1.92%	7.91%	0.4900
55	PECO ENERGY	0.3969	0.4009	0.4050	0.4091	1.0190%	27.7681	2.49%	10.35%	0.3800
56	PENNSYLVANIA POWER & LIGHT CO.	0.4091	0.4131	0.4171	0.4212	0.9740%	21.4839	2.93%	12.26%	0.4175
57	PORTLAND GENERAL CORP.	0.2890	0.2947	0.3005	0.3064	1.9600%	19.6304	3.52%	14.84%	0.3000
58	POTOMAC ELECTRIC POWER CO.	0.4144	0.4180	0.4216	0.4253	0.8688%	20.8218	2.91%	12.16%	0.4150
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.5684	0.5690	0.5696	0.5703	0.1100%	26.9479	2.23%	9.21%	0.5400
60	PUBLIC SERVICE OF COLORADO	0.5243	0.5272	0.5302	0.5332	0.5679%	27.6499	2.50%	10.37%	0.5000
61	PUGET SOUND POWER & LIGHT	0.4663	0.4717	0.4771	0.4826	1.1484%	20.7924	3.47%	14.62%	0.4600
62	ROCHESTER GAS & ELECTRIC CORP.	0.4612	0.4599	0.4587	0.4574	-0.2793%	21.2941	1.87%	7.69%	0.4400
63	SAN DIEGO GAS & ELECTRIC CO.	0.3926	0.3947	0.3968	0.3990	0.5381%	19.9868	2.53%	10.53%	0.3800
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.7135	0.7231	0.7327	0.7425	1.3374%	48.3634	2.87%	12.00%	0.7050
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.2546	0.2564	0.2582	0.2600	0.6916%	13.7278	2.59%	10.75%	0.2500
66	SIERRA PACIFIC RESOURCES	0.2948	0.2974	0.3000	0.3026	0.8752%	20.6547	2.34%	9.70%	0.2800
67	SOUTHERN CO.	0.3082	0.3109	0.3136	0.3163	0.8720%	19.8348	2.47%	10.24%	0.2950
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.4149	0.4207	0.4266	0.4326	1.4028%	29.8138	2.85%	11.91%	0.4125
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.5544	0.5594	0.5645	0.5696	0.9092%	27.6267	2.97%	12.42%	0.5500
70	ST. JOSEPH LIGHT & POWER CO.	0.4962	0.4985	0.5008	0.5031	0.4560%	28.6403	2.21%	9.15%	0.4500
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.2671	0.2698	0.2725	0.2753	1.0087%	20.8726	2.33%	9.64%	0.2525
72	TEXAS UTILITIES CO.	0.8162	0.8259	0.8357	0.8456	1.1880%	35.0881	3.60%	15.19%	0.7700
73	THE DETROIT EDISON CO.	0.4990	0.5122	0.5259	0.5398	2.6566%	30.9728	4.40%	18.79%	0.5150
74	THE MONTANA POWER CO.	0.4145	0.4194	0.4243	0.4292	1.1682%	24.9480	2.89%	12.07%	0.4000
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.3148	0.3107	0.3067	0.3027	-1.2992%	13.2871	0.98%	3.97%	0.2000
76	UNION ELECTRIC CO.	0.5967	0.6016	0.6065	0.6115	0.8235%	36.4525	2.50%	10.39%	0.5950
77	UNITED ILLUMINATING CO.	0.7296	0.7353	0.7411	0.7469	0.7831%	33.3583	3.02%	12.65%	0.6900
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.4558	0.4638	0.4719	0.4802	1.7471%	31.7691	3.26%	13.68%	0.4300
79	WASHINGTON WATER POWER CO.	0.3190	0.3224	0.3259	0.3294	1.0677%	15.8708	3.14%	13.18%	0.3100
80	WESTERN RESOURCES, INC.	0.5013	0.5099	0.5187	0.5277	1.7246%	31.4264	3.40%	14.33%	0.4950
81	WISCONSIN ENERGY CORP.	0.3772	0.3799	0.3825	0.3852	0.6969%	26.7246	2.14%	8.83%	0.3525
82	WISCONSIN PUBLIC SERVICE CORP.	0.4655	0.4709	0.4763	0.4818	1.1546%	30.7372	2.72%	11.34%	0.4550
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.4976	0.4993	0.5010	0.5027	0.3379%	28.9482	2.07%	8.56%	0.4800

Summary Statistics:		
	Mean =	11.46%
	Median =	11.17%
	Min =	3.97%
	Max =	24.86%

Investor Owned Utilities
VG-Q920 DGM+
Source: CRSP; Thomson Financial

		[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
		ted Projected Dividends			Discounted Projected Dividends				Terminal Price	Q3 1994
	Company	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)	Q2 1996 (DIVT)	(PTERM)	Stock Price
1	ALLEGHENY POWER SYSTEM, INC.	0.4020	0.3957	0.3895	0.3834	0.3774	0.3701	0.3629	18.3256	21.4167
2	AMERICAN ELECTRIC POWER, INC.	0.5910	0.5770	0.5634	0.5501	0.5371	0.5269	0.5169	26.6626	31.1250
3	ATLANTIC ENERGY, INC.	0.3722	0.3596	0.3473	0.3355	0.3240	0.3174	0.3109	14.8731	17.6250
4	BALTIMORE GAS AND ELECTRIC CO.	0.3739	0.3671	0.3604	0.3538	0.3474	0.3417	0.3361	20.0980	22.9582
5	BOSTON EDISON CO.	0.4543	0.4516	0.4489	0.4462	0.4435	0.4351	0.4269	22.1199	25.6664
6	CAROLINA POWER AND LIGHT	0.4256	0.4222	0.4188	0.4154	0.4121	0.4051	0.3983	23.1358	26.4583
7	CENTERIOR ENERGY CORP.	0.1993	0.1989	0.1984	0.1979	0.1974	0.1930	0.1886	8.2183	9.7916
8	CENTRAL & SOUTH WEST CORP.	0.4211	0.4117	0.4025	0.3935	0.3846	0.3774	0.3703	19.2720	22.4580
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.5019	0.4888	0.4761	0.4638	0.4517	0.4429	0.4342	21.7206	25.5000
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.3372	0.3248	0.3128	0.3013	0.2901	0.2862	0.2823	20.5003	23.0000
11	CENTRAL MAINE POWER CO.	0.1945	0.1852	0.1764	0.1680	0.1599	0.1575	0.1551	10.0785	11.5000
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.3301	0.3212	0.3125	0.3041	0.2959	0.2885	0.2812	10.9283	13.4168
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.6096	0.5969	0.5844	0.5723	0.5603	0.5486	0.5372	25.2090	29.8333
14	CINCINNATI GAS & ELECTRIC CO.	0.4194	0.4093	0.3995	0.3899	0.3806	0.3735	0.3665	19.2480	22.4166
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.4769	0.4598	0.4433	0.4274	0.4120	0.4053	0.3986	23.8519	27.3751
16	CMS ENERGY CORP.	0.2118	0.2114	0.2110	0.2105	0.2101	0.2080	0.2060	20.5293	22.2082
17	COMMONWEALTH EDISON CO.	0.3918	0.4124	0.4341	0.4569	0.4809	0.4700	0.4594	19.8278	23.3334
18	COMMONWEALTH ENERGY SYSTEM	0.7243	0.6977	0.6721	0.6475	0.6237	0.6130	0.6024	34.3361	39.6667
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.4951	0.4781	0.4616	0.4457	0.4304	0.4229	0.4155	23.3088	26.9581
20	DELMARVA POWER & LIGHT CO.	0.3702	0.3564	0.3432	0.3305	0.3182	0.3123	0.3065	16.1528	18.8750
21	DOMINION RESOURCES	0.6214	0.6093	0.5975	0.5859	0.5744	0.5647	0.5552	32.3392	37.0827
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.2960	0.2926	0.2892	0.2859	0.2826	0.2783	0.2741	17.7479	20.0417
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.4179	0.4125	0.4072	0.4019	0.3968	0.3911	0.3856	26.6844	29.9174
24	DUKE POWER CO.	0.4856	0.4778	0.4701	0.4626	0.4552	0.4495	0.4438	34.9320	38.6666
25	EASTERN UTILITIES ASSOCIATES	0.3712	0.3609	0.3509	0.3411	0.3316	0.3267	0.3218	21.2941	24.0834
26	EMPIRE DISTRICT ELECTRIC	0.3183	0.3176	0.3168	0.3161	0.3154	0.3088	0.3024	14.2754	16.7908
27	ENTERGY CORP.	0.4216	0.4098	0.3984	0.3872	0.3763	0.3700	0.3638	21.3646	24.5418
28	FLORIDA PROGRESS CORP.	0.4911	0.4835	0.4759	0.4685	0.4612	0.4530	0.4450	24.7268	28.5001
29	FPL GROUP, INC.	0.4155	0.4102	0.4050	0.3999	0.3949	0.3896	0.3844	28.5721	31.7917
30	GENERAL PUBLIC UTILITIES CORP.	0.4465	0.4384	0.4304	0.4226	0.4149	0.4075	0.4003	22.1310	25.5418
31	GREEN MOUNTAIN POWER CORP.	0.5163	0.5052	0.4944	0.4838	0.4734	0.4636	0.4539	21.3710	25.2917
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.5743	0.5704	0.5666	0.5628	0.5590	0.5482	0.5377	27.3760	31.8749
33	HOUSTON INDUSTRIES, INC.	0.7353	0.7144	0.6940	0.6742	0.6550	0.6414	0.6280	29.5492	35.0416
34	IDAHO POWER CO.	0.4456	0.4427	0.4398	0.4369	0.4340	0.4254	0.4169	20.5774	24.0836
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.5109	0.4999	0.4891	0.4785	0.4682	0.4592	0.4504	23.0764	26.9576
36	INTERSTATE POWER CO.									
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.4256	0.4187	0.4120	0.4053	0.3987	0.3904	0.3823	17.9427	21.2082
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.5158	0.5039	0.4923	0.4809	0.4698	0.4618	0.4539	26.1334	30.0417
39	KANSAS CITY POWER & LIGHT CO.	0.3813	0.3769	0.3726	0.3684	0.3641	0.3574	0.3507	18.4651	21.4165
40	KU ENERGY CO.	0.3970	0.3893	0.3818	0.3744	0.3671	0.3616	0.3563	23.6700	26.7074
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.5324	0.5261	0.5199	0.5138	0.5077	0.5004	0.4932	33.9105	38.0417
42	LONG ISLAND LIGHTING CO	0.4268	0.4140	0.4017	0.3897	0.3780	0.3688	0.3598	14.3995	17.5834
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.3932	0.3868	0.3806	0.3745	0.3685	0.3632	0.3579	24.3503	27.3750
44	MINNESOTA POWER & LIGHT CO.	0.4897	0.4887	0.4876	0.4866	0.4856	0.4758	0.4662	22.6972	26.5824
45	NEVADA POWER CO.	0.3893	0.3794	0.3697	0.3604	0.3512	0.3446	0.3381	17.5680	20.5006
46	NEW ENGLAND ELECTRIC SYSTEM	0.5763	0.5686	0.5610	0.5534	0.5460	0.5358	0.5258	27.6414	32.0833
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.5279	0.5145	0.5015	0.4888	0.4764	0.4644	0.4526	17.4406	21.4167
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.3566	0.3512	0.3460	0.3408	0.3357	0.3315	0.3273	25.7510	28.5001
49	NORTHEAST UTILITIES	0.4505	0.4427	0.4350	0.4274	0.4200	0.4115	0.4031	19.4446	22.8749
50	NORTHERN STATES POWER CO.	1.3182	1.2787	1.2403	1.2032	1.1671	1.1297	1.0934	33.0004	42.7509
51	OHIO EDISON CO.	0.3658	0.3584	0.3512	0.3442	0.3373	0.3307	0.3243	16.3382	19.1250
52	OKLAHOMA GAS & ELECTRIC CO.	0.6371	0.6229	0.6090	0.5954	0.5821	0.5709	0.5599	28.4494	33.2917
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.6273	0.6169	0.6066	0.5966	0.5867	0.5741	0.5618	25.6482	30.4582

Investor Owned Utilities

VG-Q920 DGM+

Source: CRSP; Thomson Financial

		[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
		ted Projected Dividends			Discounted Projected Dividends				Terminal Price	Q3 1994
	Company	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)	Q2 1996 (DIVT)	(PTERM)	Stock Price
54	PACIFIC GAS & ELECTRIC CO.	0.4896	0.4886	0.4875	0.4865	0.4854	0.4744	0.4637	19.9672	23.8329
55	PECO ENERGY	0.3736	0.3678	0.3620	0.3564	0.3509	0.3459	0.3409	23.3726	26.2500
56	PENNSYLVANIA POWER & LIGHT CO.	0.4025	0.3898	0.3775	0.3656	0.3540	0.3473	0.3407	17.5463	20.5412
57	PORTLAND GENERAL CORP.	0.2845	0.2736	0.2630	0.2529	0.2431	0.2395	0.2358	15.4077	17.5002
58	POTOMAC ELECTRIC POWER CO.	0.4002	0.3895	0.3791	0.3689	0.3590	0.3519	0.3449	17.0324	20.0409
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.5409	0.5328	0.5248	0.5169	0.5091	0.4986	0.4883	23.0989	27.2503
60	PUBLIC SERVICE OF COLORADO	0.4862	0.4804	0.4747	0.4690	0.4635	0.4547	0.4462	23.2665	27.0413
61	PUGET SOUND POWER & LIGHT	0.4353	0.4244	0.4137	0.4033	0.3932	0.3844	0.3758	16.3767	19.6667
62	ROCHESTER GAS & ELECTRIC CORP.	0.4456	0.4392	0.4328	0.4266	0.4204	0.4116	0.4029	18.7059	22.1250
63	SAN DIEGO GAS & ELECTRIC CO.	0.3727	0.3660	0.3593	0.3528	0.3464	0.3397	0.3331	16.7749	19.6249
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.6818	0.6656	0.6498	0.6344	0.6193	0.6101	0.6010	39.6658	44.8327
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.2420	0.2374	0.2329	0.2285	0.2241	0.2200	0.2159	11.4817	13.3325
66	SIERRA PACIFIC RESOURCES	0.2765	0.2730	0.2695	0.2660	0.2626	0.2588	0.2551	17.5667	19.7083
67	SOUTHERN CO.	0.2898	0.2854	0.2812	0.2770	0.2728	0.2686	0.2644	16.7242	18.9583
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.3993	0.3892	0.3794	0.3698	0.3604	0.3553	0.3503	24.4837	27.5000
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.5271	0.5146	0.5024	0.4905	0.4789	0.4693	0.4599	22.5073	26.5000
70	ST. JOSEPH LIGHT & POWER CO.	0.4328	0.4358	0.4388	0.4418	0.4448	0.4372	0.4296	24.5725	28.0833
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.2505	0.2473	0.2442	0.2411	0.2381	0.2350	0.2320	17.7677	19.7083
72	TEXAS UTILITIES CO.	0.7213	0.7118	0.7024	0.6931	0.6840	0.6680	0.6525	27.3970	33.0001
73	THE DETROIT EDISON CO.	0.4635	0.4474	0.4318	0.4168	0.4023	0.3956	0.3890	22.9135	26.3750
74	THE MONTANA POWER CO.	0.3914	0.3832	0.3751	0.3672	0.3595	0.3535	0.3476	20.4390	23.4166
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.1962	0.2181	0.2425	0.2697	0.2998	0.2931	0.2865	12.4112	14.4170
76	UNION ELECTRIC CO.	0.5915	0.5747	0.5585	0.5427	0.5273	0.5187	0.5102	30.6639	35.0825
77	UNITED ILLUMINATING CO.	0.6759	0.6638	0.6519	0.6402	0.6287	0.6150	0.6016	27.0829	32.2500
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.4166	0.4094	0.4022	0.3952	0.3883	0.3826	0.3770	25.3820	28.5834
79	WASHINGTON WATER POWER CO.	0.2957	0.2899	0.2843	0.2787	0.2733	0.2678	0.2624	12.7796	15.0418
80	WESTERN RESOURCES, INC.	0.4692	0.4575	0.4460	0.4349	0.4240	0.4172	0.4104	24.8625	28.4167
81	WISCONSIN ENERGY CORP.	0.3525	0.3491	0.3458	0.3426	0.3394	0.3346	0.3299	23.0461	25.7924
82	WISCONSIN PUBLIC SERVICE CORP.	0.4384	0.4303	0.4224	0.4146	0.4070	0.4008	0.3947	25.4694	28.8325
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.4799	0.4720	0.4642	0.4566	0.4491	0.4414	0.4339	25.0730	28.7500

Investor Owned Utilities

Variable-Growth DGM Model with Thomson Financial Qtrs. 9 to 20 Earnings Growth Rate (VG-Q920 DGM)+

Notes:

+ The VG-Q920 DGM model is discussed in Stewart Myers and Lynda S. Borucki, "Discounted Cash Flow Estimates of the Cost of Equity Capital--A Case Study," Financial Markets, Institutions & Instruments, V. 3, N. 3, August 1994, pp. 9-45.

[1] The average of the end-of-month stock prices reported for Q3 1994.
  Source: CRSP.
[2] The projected annual growth in earnings per share for FY 1994.
  Source: Thomson Financial
[3] The projected annual growth in earnings per share for FY 1995.
  Source: Thomson Financial
[4] The implied average annual growth in earnings per share for FY 1996-1998.
  Source: Thomson Financial
[5] The actual dividend paid to shareholders during Q3 1994.
  Source: CRSP.
[6] The projected dividends to be paid to shareholders for Q4 1994.
  Formula: $(\text{Previous dividend}) * (1 + [2])^{1/4}$
[7]-[10] The projected dividends to be paid to shareholders for Q1 1995 through Q4 1995.
  Formula: $(\text{Previous dividend}) * (1 + [3])^{1/4}$
[11]-[13] The projected divided to be paid to shareholder for Q1 1996 through Q3 1996.
  Formula: $(\text{Previous dividend}) * (1 + [4])^{1/4}$
[14] The long-term average quarterly growth rate of earnings per share.
  Formula: $(1 + [4])^{1/4} - 1$
[15] The terminal price, or present value of all future dividend streams, at time T.
  Formula: $[13] / ([16] - [14])$
[16] The derived quarterly cost of equity.
  Formula: $(1 + [17])^{1/4} - 1$
[17] The cost of equity, at an annual rate, as predicted by the VG-Q920 DGM model.
  This is given as the r that solves the following formula.
  Formula: $[18] + [19] + [20] + [21] + [22] + [23] + [24] + [25] + [26] = [27] = [1]$
[18]-[25] The present value of the quarterly dividends paid to shareholders for Q3 1994 through Q2 1996.
  The Q3 1994 dividend is paid in the first period, with time (t) = 0.
  Note that t=T is the final period.
  Formula: $(\text{Dividend Paid in Period } t) / (1 + [17])^{t/4}$
[26] The present value of the terminal stock price.
  Formula: $[15] / (1 + [17])^{T/4}$
[27] The Q3 1994 stock price, given as the sum of the present value of the current and future dividend streams and the present value of the terminal stock price.
  This should be equivalent to the reported stock price for Q3 1994, given at [1].
  Formula: $[18] + [19] + [20] + [21] + [22] + [23] + [24] + [25] + [26]$

Investor Owned Utilities

Variable-Growth DGM Model with Thomson Long-Run Earnings Growth Forecast (VG-IBES DGM)+

Source: *CRSP; Thomson Financial*

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
									Nominal Projected Dividends			
	Company	Q3 1994 Stock Price	Thomson Financial 1994 EPS Growth Forecast	Thomson Financial 1995 EPS Growth Forecast	Thomson Financial 1996 -1998 EPS Growth Forecast	Q3 1994 Dividend (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)
1	ALLEGHENY POWER SYSTEM, INC.	21.417	1.53%	3.07%	1.52%	0.4100	0.4116	0.4147	0.4178	0.4210	0.4242	0.4258
2	AMERICAN ELECTRIC POWER, INC.	31 125	4.12%	0.57%	2.47%	0.6000	0.6061	0.6069	0.6078	0.6087	0.6095	0.6132
3	ATLANTIC ENERGY, INC.	17.625	-1.30%	-1.69%	3.97%	0.3850	0.3837	0.3821	0.3805	0.3789	0.3773	0.3810
4	BALTIMORE GAS AND ELECTRIC CO.	22.958	3.87%	3.02%	3.75%	0.3800	0.3836	0.3865	0.3894	0.3923	0.3952	0.3989
5	BOSTON EDISON CO.	25.667	20.41%	3.44%	-1.84%	0.4400	0.4609	0.4648	0.4688	0.4728	0.4768	0.4746
6	CAROLINA POWER AND LIGHT	26.458	8.42%	4.40%	0.70%	0.4250	0.4337	0.4384	0.4431	0.4479	0 4527	0 4535
7	CENTERIOR ENERGY CORP.	9.792	6.77%	7.11%	-1.21%	0.2000	0.2033	0.2068	0.2104	0.2141	0.2178	0.2171
8	CENTRAL & SOUTH WEST CORP	22.458	7.27%	1.65%	3.13%	0.4250	0.4325	0.4343	0.4361	0 4379	0.4397	0.4431
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	25.500	-2.18%	1.47%	4.15%	0.5200	0.5171	0.5190	0.5209	0.5228	0.5248	0.5301
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	23.000	-14.74%	0.66%	10.77%	0.3650	0.3507	0.3513	0.3519	0.3525	0.3530	0.3622
11	CENTRAL MAINE POWER CO.	11.500	-30 35%	2.70%	17.46%	0.2250	0.2056	0.2069	0.2083	0.2097	0.2111	0.2198
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	13.417	-11.99%	5.54%	6.36%	0.3550	0.3438	0.3485	0.3532	0.3580	0.3629	0.3685
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	29.833	6.87%	1.75%	1.74%	0.6150	0.6253	0.6280	0.6307	0.6335	0.6362	0.6390
14	CINCINNATI GAS & ELECTRIC CO.	22.417	1.37%	1.69%	3.91%	0.4300	0.4315	0.4333	0.4351	0.4369	0.4388	0.4430
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	27.375	-3.95%	0.28%	8.62%	0.5000	0.4950	0.4953	0.4957	0.4960	0.4964	0.5067
16	CMS ENERGY CORP.	22.208	11.11%	6.54%	3.18%	0.2100	0.2156	0.2190	0.2225	0.2261	0.2297	0.2315
17	COMMONWEALTH EDISON CO.	23.333	0.67%	34.17%	-0.25%	0.4000	0.4007	0.4312	0.4641	0.4995	0.5376	0.5373
18	COMMONWEALTH ENERGY SYSTEM	39.667	-1.03%	-2.02%	6.13%	0.7500	0.7481	0.7442	0.7405	0.7367	0.7329	0.7439
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	26.958	6.21%	-3.97%	2.93%	0.5000	0.5076	0.5025	0.4974	0.4924	0.4874	0.4910
20	DELMARVA POWER & LIGHT CO.	18.875	-2.01%	-1.47%	6.33%	0.3850	0.3831	0.3816	0.3802	0.3788	0.3774	0.3833
21	DOMINION RESOURCES	37.083	1.67%	2.45%	3.53%	0.6350	0.6376	0.6415	0.6454	0.6493	0.6532	0.6589
22	DPL INC. (DAYTON POWER & LIGHT CO.)	20.042	10.05%	3.66%	2.12%	0.2950	0.3021	0.3049	0.3076	0.3104	0.3132	0.3149
23	DQE, INC. (DUQUESNE LIGHT CO.)	29.917	6.64%	3.32%	2.75%	0.4200	0.4268	0.4303	0.4338	0.4374	0.4410	0.4440
24	DUKE POWER CO.	38.667	5.30%	2.33%	3.79%	0.4900	0.4964	0.4992	0.5021	0.5050	0.5080	0.5127
25	EASTERN UTILITIES ASSOCIATES	24.083	-1.87%	1.43%	6.92%	0.3850	0.3832	0.3846	0.3859	0.3873	0.3887	0.3952
26	EMPIRE DISTRICT ELECTRIC	16.792	7.76%	9.00%	1.18%	0.3200	0.3260	0.3331	0.3404	0.3478	0.3554	0.3564
27	ENTERGY CORP	24.542	-10.43%	3.72%	8.62%	0.4500	0.4378	0.4418	0.4459	0.4499	0.4541	0.4636
28	FLORIDA PROGRESS CORP.	28.500	6.35%	3.07%	2.20%	0.4950	0.5027	0.5065	0.5103	0.5142	0.5181	0.5209
29	FPL GROUP, INC.	31.792	4.85%	4.05%	3.79%	0.4200	0.4250	0.4292	0.4335	0.4379	0.4422	0.4464
30	GENERAL PUBLIC UTILITIES CORP.	25.542	6.34%	1.90%	2.08%	0.4500	0.4570	0.4591	0.4613	0.4635	0.4656	0.4680
31	GREEN MOUNTAIN POWER CORP.	25.292	-0.11%	1.71%	1.97%	0.5300	0.5298	0.5321	0.5344	0.5366	0.5389	0.5415
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	31.875	6.17%	7.55%	2.22%	0.5800	0.5888	0.5996	0.6106	0.6218	0.6332	0.6367
33	HOUSTON INDUSTRIES, INC.	35.042	3.12%	-0.59%	2.59%	0.7500	0.7558	0.7547	0.7535	0.7524	0.7513	0.7561
34	IDAHO POWER CO.	24.083	-5.08%	9.61%	3.87%	0.4650	0.4590	0.4696	0.4805	0.4917	0.5031	0.5079
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	26.958	0.66%	2.84%	3.88%	0.5250	0.5259	0.5296	0.5333	0.5370	0.5408	0.5460
36	INTERSTATE POWER CO.											
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	21.208	4.45%	4.33%	2.36%	0.4325	0.4372	0.4419	0.4466	0.4513	0.4562	0.4588
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	30.042	0.85%	2.37%	4.92%	0.5300	0.5311	0.5343	0.5374	0.5405	0.5437	0.5503
39	KANSAS CITY POWER & LIGHT CO.	21.417	9.60%	3.27%	0.29%	0.3800	0.3888	0.3919	0.3951	0.3983	0.4015	0.4018
40	KU ENERGY CO.	26.708	-2.11%	2.95%	4.88%	0.4100	0.4078	0.4108	0.4138	0.4168	0.4198	0.4249
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	38.042	5.02%	4.00%	2.94%	0.5375	0.5441	0.5495	0.5549	0.5604	0.5659	0.5700
42	LONG ISLAND LIGHTING CO.	17.583	-3.43%	1.09%	3.40%	0.4450	0.4411	0.4423	0.4435	0.4447	0.4459	0.4497
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	27.375	3.89%	4.32%	5.00%	0 4000	0.4038	0.4081	0.4125	0.4169	0.4213	0.4265
44	MINNESOTA POWER & LIGHT CO.	26.583	-1 79%	10.12%	2.38%	0.5050	0.5027	0.5150	0.5275	0.5404	0.5536	0.5568
45	NEVADA POWER CO	20.500	0.99%	1.59%	4.33%	0.4000	0.4010	0.4026	0.4041	0.4057	0.4073	0.4117
46	NEW ENGLAND ELECTRIC SYSTEM	32.083	9.42%	2.75%	0.57%	0.5750	0.5881	0.5921	0.5961	0.6002	0.6043	0.6052
47	NEW YORK STATE ELECTRIC & GAS CORP	21.417	-2.15%	4 09%	4 09%	0.5500	0.5470	0 5525	0.5581	0.5637	0.5694	0.5751
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO)	28.500	6.03%	3.69%	4.72%	0 3600	0.3653	0.3686	0.3720	0.3754	0.3788	0 3832
49	NORTHEAST UTILITIES	22.875	18.87%	0.82%	-0.38%	0 4400	0.4594	0.4604	0.4613	0.4623	0.4632	0.4628
50	NORTHERN STATES POWER CO.	42.750	14.24%	1.71%	0.83%	1.3200	1.3647	1.3705	1.3763	1.3821	1.3880	1.3908
51	OHIO EDISON CO	19.125	1.15%	3.07%	3.32%	0.3750	0.3761	0.3789	0.3818	0.3847	0.3876	0.3908
52	OKLAHOMA GAS & ELECTRIC CO	33.292	-5.87%	2.10%	3.36%	0.6650	0.6550	0.6584	0.6619	0.6653	0.6688	0.6744
53	ORANGE & ROCKLAND INDUSTRIES, INC	30.458	2.78%	4.17%	2.13%	0.6400	0.6444	0.6510	0.6577	0.6645	0.6713	0.6748
54	PACIFIC GAS & ELECTRIC CO.	23.833	7.57%	6.99%	-1.55%	0.4900	0.4990	0.5075	0.5162	0.5250	0.5339	0.5318
55	PECO ENERGY	26.250	3.05%	3.66%	4.14%	0.3800	0.3829	0.3863	0.3898	0.3933	0.3969	0.4009
56	PENNSYLVANIA POWER & LIGHT CO.	20.542	-3.02%	-1.25%	3.95%	0.4175	0.4143	0.4130	0.4117	0.4104	0.4091	0.4131
57	PORTLAND GENERAL CORP.	17.500	-7.05%	-1.87%	8.07%	0.3000	0.2946	0.2932	0.2918	0.2904	0.2890	0.2947
58	POTOMAC ELECTRIC POWER CO.	20.042	-2.95%	0.60%	3.52%	0.4150	0.4119	0.4125	0.4131	0.4138	0.4144	0.4180
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	27.250	9.93%	2.80%	0.44%	0.5400	0.5529	0.5568	0.5606	0.5645	0.5684	0.5690
60	PUBLIC SERVICE OF COLORADO	27.042	-1.30%	5.20%	2.29%	0.5000	0.4984	0.5047	0.5112	0.5177	0.5243	0.5272
61	PUGET SOUND POWER & LIGHT	19.667	-8.11%	3.54%	4.67%	0.4600	0.4504	0.4543	0.4583	0.4623	0.4663	0.4717
62	ROCHESTER GAS & ELECTRIC CORP.	22.125	13.25%	1.61%	-1.11%	0.4400	0.4539	0.4557	0.4575	0.4594	0.4612	0.4599
63	SAN DIEGO GAS & ELECTRIC CO.	19.625	2.32%	2.73%	2.17%	0.3800	0.3822	0.3848	0.3874	0.3900	0.3926	0.3947
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	44.833	-2.05%	1.73%	5.46%	0.7050	0.7014	0.7044	0.7074	0.7105	0.7135	0.7231
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	13.333	-2.74%	2.56%	2.80%	0.2500	0.2483	0.2498	0.2514	0.2530	0.2546	0.2564
66	SIERRA PACIFIC RESOURCES	19.708	4.36%	4.17%	3.55%	0.2800	0.2830	0.2859	0.2888	0.2918	0.2948	0.2974

Investor Owned Utilities

Variable-Growth DGM Model with Thomson Long-Run Earnings Growth Forecast (VG-IBES DGM)[+]

Source: *CRSP; Thomson Financial*

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
			Thomson Financial	Thomson Financial	Thomson Financial							
		Q3 1994	1994 EPS	1995 EPS	1996 -1998 EPS	Q3 1994			Nominal Projected Dividends			
	Company	Stock Price	Growth Forecast	Growth Forecast	Growth Forecast	Dividend (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)
67	SOUTHERN CO.	18.958	2.60%	3.80%	3.53%	0.2950	0.2969	0.2997	0.3025	0.3053	0.3082	0.3109
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	27.500	-1.72%	1.01%	5.73%	0.4125	0.4107	0.4118	0.4128	0.4138	0.4149	0.4207
69	SOUTHWESTERN PUBLIC SERVICE CO.	26.500	-5.14%	2.13%	3.69%	0.5500	0.5428	0.5457	0.5485	0.5514	0.5544	0.5594
70	ST JOSEPH LIGHT & POWER CO.	28.083	-6.57%	12.16%	1.84%	0.4500	0.4424	0.4553	0.4686	0.4822	0.4962	0.4985
71	TECO ENERGY INC. (TAMPA ELECTRIC)	19.708	6.14%	4.22%	4.10%	0.2525	0.2563	0.2590	0.2616	0.2644	0.2671	0.2698
72	TEXAS UTILITIES CO.	33.000	-11.30%	9.22%	4.84%	0.7700	0.7473	0.7639	0.7810	0.7984	0.8162	0.8259
73	THE DETROIT EDISON CO.	26.375	-22.08%	3.13%	11.06%	0.5150	0.4839	0.4876	0.4914	0.4952	0.4990	0.5122
74	THE MONTANA POWER CO.	23.417	2.77%	2.93%	4.76%	0.4000	0.4027	0.4057	0.4086	0.4116	0.4145	0.4194
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	14.417	-3.79%	58.93%	-5.10%	0.2000	0.1981	0.2224	0.2497	0.2804	0.3148	0.3107
76	UNION ELECTRIC CO.	35.083	7.79%	-1.59%	3.33%	0.5950	0.6063	0.6039	0.6014	0.5990	0.5967	0.6016
77	UNITED ILLUMINATING CO.	32.250	3.73%	4.77%	3.17%	0.6900	0.6963	0.7045	0.7128	0.7211	0.7296	0.7353
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	28.583	0.20%	5.96%	7.17%	0.4300	0.4302	0.4365	0.4428	0.4493	0.4558	0.4638
79	WASHINGTON WATER POWER CO.	15.042	-6.33%	4.61%	4.34%	0.3100	0.3050	0.3084	0.3119	0.3155	0.3190	0.3224
80	WESTERN RESOURCES, INC.	28.417	-7.73%	3.33%	7.08%	0.4950	0.4851	0.4891	0.4932	0.4972	0.5013	0.5099
81	WISCONSIN ENERGY CORP.	25.792	8.77%	4.79%	2.82%	0.3525	0.3600	0.3642	0.3685	0.3728	0.3772	0.3799
82	WISCONSIN PUBLIC SERVICE CORP.	28.833	-4.08%	3.38%	4.70%	0.4550	0.4503	0.4540	0.4578	0.4616	0.4655	0.4709
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	28.750	8.46%	1.58%	1.36%	0.4800	0.4898	0.4918	0.4937	0.4956	0.4976	0.4993

Investor Owned Utilities

VG-IBES DGM^{+}

Source: *CRSP; Thomson Financial*

		[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]
		Nominal Projected Dividends		Mean 5 Yr EPS Growth Forecast	Long-Run Growth Forecast	Terminal Price	Quarterly Cost	VG-VL	Discounted Projected Dividends		
	Company	Q2 1996 (DIVT)	Q3 1996 (DIVT+1)	Annual	Qtrly (GTERM)	(PTERM)	of Equity	DGM ROE	Q3 1994 (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)
1	ALLEGHENY POWER SYSTEM, INC.	0.4274	0.4290	1.83%	0.4544%	21.6910	2.43%	10.09%	0.4100	0.4018	0.3952
2	AMERICAN ELECTRIC POWER, INC.	0.6170	0.6208	2.41%	0.5974%	31.7984	2.55%	10.60%	0.6000	0.5910	0.5771
3	ATLANTIC ENERGY, INC.	0.3847	0.3884	1.75%	0.4347%	17.7742	2.62%	10.90%	0.3850	0.3739	0.3629
4	BALTIMORE GAS AND ELECTRIC CO	0.4025	0.4063	3.63%	0.8947%	24.0270	2.59%	10.75%	0.3800	0.3740	0.3672
5	BOSTON EDISON CO.	0.4724	0.4702	3.33%	0.8223%	26.6132	2.59%	10.77%	0.4400	0.4493	0.4417
6	CAROLINA POWER AND LIGHT	0.4543	0.4551	2.94%	0.7267%	27.3601	2.39%	9.91%	0.4250	0.4236	0.4181
7	CENTERIOR ENERGY CORP.	0.2164	0.2158	1.98%	0.4901%	9.9221	2.66%	11.09%	0.2000	0.1980	0.1962
8	CENTRAL & SOUTH WEST CORP.	0.4465	0.4499	3.64%	0.8989%	23.4272	2.82%	11.76%	0.4250	0.4207	0.4108
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.5355	0.5410	2.32%	0.5750%	26.0319	2.65%	11.04%	0.5200	0.5038	0.4925
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.3716	0.3812	3.13%	0.7723%	23.9784	2.36%	9.79%	0.3650	0.3426	0.3353
11	CENTRAL MAINE POWER CO.	0.2288	0.2382	3.00%	0.7417%	11.9968	2.73%	11.36%	0.2250	0.2001	0.1961
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.3743	0.3801	2.25%	0.5578%	13.6675	3.34%	14.04%	0.3550	0.3327	0.3264
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.6418	0.6445	2.75%	0.6805%	30.5973	2.79%	11.62%	0.6150	0.6083	0.5944
14	CINCINNATI GAS & ELECTRIC CO.	0.4472	0.4516	2.95%	0.7295%	23.1384	2.68%	11.16%	0.4300	0.4202	0.4109
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.5173	0.5281	4.30%	1.0581%	28.9694	2.88%	12.03%	0.5000	0.4811	0.4680
16	CMS ENERGY CORP.	0.2333	0.2351	5.39%	1.3211%	24.0995	2.30%	9.51%	0.2100	0.2108	0.2093
17	COMMONWEALTH EDISON CO.	0.5369	0.5366	6.04%	1.4764%	25.5593	3.58%	15.09%	0.4000	0.3868	0.4020
18	COMMONWEALTH ENERGY SYSTEM	0.7551	0.7664	3.00%	0.7417%	40.9864	2.61%	10.86%	0.7500	0.7290	0.7068
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.4945	0.4981	2.15%	0.5332%	27.4028	2.35%	9.74%	0.5000	0.4959	0.4797
20	DELMARVA POWER & LIGHT CO.	0.3892	0.3952	3.03%	0.7487%	19.4906	2.78%	11.58%	0.3850	0.3727	0.3613
21	DOMINION RESOURCES	0.6647	0.6705	2.94%	0.7270%	38.3527	2.48%	10.27%	0.6350	0.6222	0.6109
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.3165	0.3182	3.97%	0.9772%	21.1110	2.48%	10.31%	0.2950	0.2948	0.2903
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.4470	0.4500	3.63%	0.8954%	31.3761	2.33%	9.65%	0.4200	0.4171	0.4109
24	DUKE POWER CO.	0.5175	0.5223	3.80%	0.9368%	40.7333	2.22%	9.18%	0.4900	0.4856	0.4778
25	EASTERN UTILITIES ASSOCIATES	0.4019	0.4087	4.00%	0.9853%	25.4049	2.59%	10.79%	0.3850	0.3735	0.3654
26	EMPIRE DISTRICT ELECTRIC	0.3575	0.3585	4.00%	0.9853%	17.6408	3.02%	12.63%	0.3200	0.3165	0.3139
27	ENTERGY CORP.	0.4732	0.4831	3.55%	0.8759%	25.7048	2.76%	11.49%	0.4500	0.4260	0.4184
28	FLORIDA PROGRESS CORP.	0.5238	0.5266	3.19%	0.7881%	29.5641	2.57%	10.68%	0.4950	0.4901	0.4814
29	FPL GROUP, INC.	0.4505	0.4547	4.05%	0.9983%	33.6258	2.35%	9.74%	0.4200	0.4152	0.4098
30	GENERAL PUBLIC UTILITIES CORP.	0.4705	0.4729	2.88%	0.7124%	26.3433	2.51%	10.41%	0.4500	0.4458	0.4369
31	GREEN MOUNTAIN POWER CORP.	0.5442	0.5469	1.50%	0.3729%	25.4287	2.52%	10.48%	0.5300	0.5168	0.5062
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.6402	0.6437	4.05%	0.9975%	33.5495	2.92%	12.18%	0.5800	0.5721	0.5661
33	HOUSTON INDUSTRIES, INC.	0.7610	0.7658	2.05%	0.5086%	35.4999	2.67%	11.10%	0.7500	0.7362	0.7160
34	IDAHO POWER CO.	0.5127	0.5176	3.12%	0.7702%	25.0102	2.84%	11.85%	0.4650	0.4463	0.4441
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.5512	0.5565	3.02%	0.7466%	27.8629	2.74%	11.43%	0.5250	0.5118	0.5017
36	INTERSTATE POWER CO.										
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.4615	0.4642	3.17%	0.7824%	21.9380	2.90%	12.11%	0.4325	0.4249	0.4173
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.5570	0.5637	3.59%	0.8846%	31.4027	2.68%	11.16%	0.5300	0.5173	0.5067
39	KANSAS CITY POWER & LIGHT CO.	0.4021	0.4024	2.69%	0.6648%	21.9999	2.49%	10.35%	0.3800	0.3794	0.3731
40	KU ENERGY CO.	0.4300	0.4351	3.06%	0.7564%	27.7537	2.32%	9.63%	0.4100	0.3986	0.3923
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.5741	0.5783	3.57%	0.8800%	39.8672	2.33%	9.65%	0.5375	0.5317	0.5247
42	LONG ISLAND LIGHTING CO.	0.4535	0.4573	1.54%	0.3822%	17.6313	2.98%	12.44%	0.4450	0.4284	0.4171
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.4317	0.4370	4.64%	1.1403%	29.2064	2.64%	10.97%	0.4000	0.3935	0.3874
44	MINNESOTA POWER & LIGHT CO.	0.5601	0.5634	3.02%	0.7466%	27.5451	2.79%	11.64%	0.5050	0.4891	0.4874
45	NEVADA POWER CO.	0.4161	0.4205	3.10%	0.7662%	21.2096	2.75%	11.46%	0.4000	0.3903	0.3813
46	NEW ENGLAND ELECTRIC SYSTEM	0.6060	0.6069	2.73%	0.6744%	32.9724	2.51%	10.45%	0.5750	0.5737	0.5634
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.5809	0.5868	2.81%	0.6955%	21.9511	3.37%	14.17%	0.5500	0.5292	0.5171
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.3876	0.3921	4.77%	1.1724%	30.5214	2.46%	10.20%	0.3600	0.3566	0.3512
49	NORTHEAST UTILITIES	0.4623	0.4619	3.45%	0.8516%	23.7038	2.80%	11.68%	0.4400	0.4469	0.4356
50	NORTHERN STATES POWER CO.	1.3937	1.3966	3.56%	0.8784%	43.8345	4.06%	17.28%	1.3200	1.3114	1.2655
51	OHIO EDISON CO.	0.3940	0.3972	2.83%	0.7009%	19.6995	2.72%	11.32%	0.3750	0.3661	0.3591
52	OKLAHOMA GAS & ELECTRIC CO.	0.6800	0.6856	1.20%	0.2987%	33.3891	2.35%	9.75%	0.6650	0.6400	0.6285
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.6784	0.6820	2.67%	0.6601%	31.2317	2.84%	11.87%	0.6400	0.6266	0.6155
54	PACIFIC GAS & ELECTRIC CO.	0.5298	0.5277	1.89%	0.4692%	24.1066	2.66%	11.06%	0.4900	0.4861	0.4816
55	PECO ENERGY	0.4050	0.4091	3.82%	0.9424%	27.6296	2.42%	10.05%	0.3800	0.3738	0.3683
56	PENNSYLVANIA POWER & LIGHT CO.	0.4171	0.4212	1.47%	0.3658%	20.6601	2.40%	9.97%	0.4175	0.4046	0.3938
57	PORTLAND GENERAL CORP.	0.3005	0.3064	2.86%	0.7068%	18.0980	2.40%	9.95%	0.3000	0.2877	0.2796
58	POTOMAC ELECTRIC POWER CO	0.4216	0.4253	1.61%	0.3999%	20.2054	2.50%	10.40%	0.4150	0.4018	0.3926
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.5696	0.5703	2.75%	0.6794%	27.9527	2.72%	11.33%	0.5400	0.5383	0.5277
60	PUBLIC SERVICE OF COLORADO	0.5302	0.5332	2.13%	0.5291%	27.5820	2.46%	10.22%	0.5000	0.4864	0.4808
61	PUGET SOUND POWER & LIGHT	0.4771	0.4826	1.76%	0.4371%	19.8775	2.86%	11.96%	0.4600	0.4378	0.4294
62	ROCHESTER GAS & ELECTRIC CORP.	0.4587	0.4574	2.16%	0.5357%	22.4426	2.57%	10.70%	0.4400	0.4425	0.4331
63	SAN DIEGO GAS & ELECTRIC CO.	0.3968	0.3990	2.31%	0.5728%	20.0327	2.56%	10.66%	0.3800	0.3726	0.3658
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.7327	0.7425	3.17%	0.7824%	46.6463	2.37%	9.84%	0.7050	0.6851	0.6721
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.2582	0.2600	1.62%	0.4021%	13.4742	2.33%	9.66%	0.2500	0.2426	0.2386
66	SIERRA PACIFIC RESOURCES	0.3000	0.3026	3.83%	0.9449%	20.7492	2.40%	9.97%	0.2800	0.2764	0.2726

Investor Owned Utilities

VG-IBES DGM^{+}

Source: *CRSP; Thomson Financial*

		[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]
		Nominal Projected Dividends		Mean 5 Yr EPS Growth Forecast	Long-Run Growth Forecast	Terminal Price	Quarterly Cost	VG-VL	Discounted Projected Dividends		
	Company	Q2 1996 (DIVT)	Q3 1996 (DIVT+1)	Annual	Qtrly (GTERM)	(PTERM)	of Equity	DGM ROE	Q3 1994 (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)
67	SOUTHERN CO.	0.3136	0.3163	3.40%	0.8394%	19.7926	2.44%	10.11%	0.2950	0.2898	0.2856
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.4266	0.4326	3.25%	0.8028%	28.6673	2.31%	9.57%	0.4125	0.4014	0.3934
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.5645	0.5696	1.55%	0.3853%	26.7147	2.52%	10.46%	0.5500	0.5295	0.5192
70	ST. JOSEPH LIGHT & POWER CO.	0.5008	0.5031	2.05%	0.5086%	28.7382	2.26%	9.35%	0.4500	0.4327	0.4354
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.2725	0.2753	4.53%	1.1131%	21.0165	2.42%	10.05%	0.2525	0.2502	0.2468
72	TEXAS UTILITIES CO.	0.8357	0.8456	2.23%	0.5517%	33.7088	3.06%	12.81%	0.7700	0.7251	0.7192
73	THE DETROIT EDISON CO.	0.5259	0.5398	1.94%	0.4809%	26.9447	2.48%	10.31%	0.5150	0.4721	0.4642
74	THE MONTANA POWER CO	0.4243	0.4292	3.99%	0.9826%	24.6500	2.72%	11.35%	0.4000	0.3921	0.3844
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.3067	0.3027	5.50%	1.3475%	15.7498	3.27%	13.73%	0.2000	0.1918	0.2085
76	UNION ELECTRIC CO.	0.6065	0.6115	3.20%	0.7906%	36.3753	2.47%	10.26%	0.5950	0.5916	0.5751
77	UNITED ILLUMINATING CO.	0.7411	0.7469	3.60%	0.8881%	33.5821	3.11%	13.04%	0.6900	0.6753	0.6626
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.4719	0.4802	5.50%	1.3475%	30.9553	2.90%	12.11%	0.4300	0.4181	0.4122
79	WASHINGTON WATER POWER CO.	0.3259	0.3294	2.17%	0.5373%	15.3415	2.68%	11.18%	0.3100	0.2970	0.2925
80	WESTERN RESOURCES, INC.	0.5187	0.5277	3.20%	0.7906%	29.5862	2.57%	10.70%	0.4950	0.4730	0.4649
81	WISCONSIN ENERGY CORP.	0.3825	0.3852	4.38%	1.0767%	27.3985	2.48%	10.31%	0.3525	0.3513	0.3468
82	WISCONSIN PUBLIC SERVICE CORP.	0.4763	0.4818	2.62%	0.6487%	29.7412	2.27%	9.39%	0.4550	0.4403	0.4341
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.5010	0.5027	2.79%	0.6893%	29.6184	2.39%	9.89%	0.4800	0.4784	0.4691

Summary Statistics:	Mean =	11.00%
	Median =	10.73%
	Min =	9.18%
	Max =	17.28%

Investor Owned Utilities

VG-IBES DGM^{+}

Source: *CRSP; Thomson Financial*

		[22]	[23]	[24]	[25]	[26]	[27]	[28]
		Discounted Projected Dividends					Terminal Price	Q3 1994
	Company	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)	Q2 1996 (DIVT)	(PTERM)	Stock Price
1	ALLEGHENY POWER SYSTEM, INC.	0.3888	0.3824	0.3762	0.3686	0.3612	18.3324	21.4167
2	AMERICAN ELECTRIC POWER, INC.	0.5636	0.5504	0.5374	0.5273	0.5173	26.6604	31.1245
3	ATLANTIC ENERGY, INC.	0.3521	0.3416	0.3315	0.3262	0.3210	14.8308	17.6250
4	BALTIMORE GAS AND ELECTRIC CO.	0.3607	0.3542	0.3478	0.3422	0.3367	20.0953	22.9580
5	BOSTON EDISON CO.	0.4342	0.4268	0.4196	0.4071	0.3950	22.2531	25.6668
6	CAROLINA POWER AND LIGHT	0.4128	0.4075	0.4023	0.3936	0.3851	23.1905	26.4586
7	CENTERIOR ENERGY CORP.	0.1944	0.1927	0.1909	0.1854	0.1800	8.2537	9.7914
8	CENTRAL & SOUTH WEST CORP.	0.4012	0.3918	0.3826	0.3750	0.3675	19.2837	22.4583
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.4816	0.4708	0.4604	0.4530	0.4458	21.6718	25.4998
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.3281	0.3210	0.3141	0.3148	0.3155	20.3634	23.0000
11	CENTRAL MAINE POWER CO.	0.1922	0.1883	0.1845	0.1870	0.1895	9.9373	11.5000
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.3201	0.3140	0.3079	0.3026	0.2974	10.8605	13.4166
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.5808	0.5675	0.5545	0.5418	0.5294	25.2414	29.8333
14	CINCINNATI GAS & ELECTRIC CO.	0.4019	0.3930	0.3844	0.3780	0.3716	19.2266	22.4166
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.4552	0.4427	0.4306	0.4273	0.4240	23.7459	27.3750
16	CMS ENERGY CORP.	0.2079	0.2065	0.2050	0.2020	0.1990	20.5576	22.2081
17	COMMONWEALTH EDISON CO.	0.4177	0.4340	0.4510	0.4351	0.4199	19.9869	23.3333
18	COMMONWEALTH ENERGY SYSTEM	0.6853	0.6645	0.6443	0.6373	0.6304	34.2189	39.6666
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.4639	0.4487	0.4340	0.4271	0.4203	23.2890	26.9585
20	DELMARVA POWER & LIGHT CO.	0.3502	0.3395	0.3291	0.3252	0.3213	16.0905	18.8749
21	DOMINION RESOURCES	0.5997	0.5888	0.5781	0.5690	0.5601	32.3195	37.0833
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.2858	0.2814	0.2770	0.2718	0.2666	17.7789	20.0415
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.4049	0.3989	0.3930	0.3867	0.3804	26.7047	29.9166
24	DUKE POWER CO.	0.4701	0.4626	0.4552	0.4494	0.4438	34.9322	38.6667
25	EASTERN UTILITIES ASSOCIATES	0.3574	0.3496	0.3419	0.3389	0.3359	21.2356	24.0832
26	EMPIRE DISTRICT ELECTRIC	0.3113	0.3088	0.3063	0.2982	0.2903	14.3263	16.7917
27	ENTERGY CORP.	0.4109	0.4036	0.3964	0.3938	0.3912	21.2511	24.5415
28	FLORIDA PROGRESS CORP.	0.4729	0.4646	0.4564	0.4474	0.4385	24.7536	28.5000
29	FPL GROUP, INC.	0.4043	0.3990	0.3937	0.3883	0.3829	28.5785	31.7918
30	GENERAL PUBLIC UTILITIES CORP.	0.4283	0.4197	0.4114	0.4034	0.3956	22.1505	25.5416
31	GREEN MOUNTAIN POWER CORP.	0.4959	0.4857	0.4758	0.4663	0.4571	21.3581	25.2918
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.5601	0.5542	0.5484	0.5358	0.5235	27.4347	31.8750
33	HOUSTON INDUSTRIES, INC.	0.6963	0.6773	0.6587	0.6457	0.6330	29.5286	35.0417
34	IDAHO POWER CO.	0.4418	0.4396	0.4374	0.4293	0.4215	20.5584	24.0833
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.4917	0.4819	0.4723	0.4641	0.4560	23.0536	26.9582
36	INTERSTATE POWER CO.							
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.4099	0.4026	0.3954	0.3865	0.3778	17.9612	21.2083
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.4964	0.4863	0.4764	0.4696	0.4628	26.0962	30.0417
39	KANSAS CITY POWER & LIGHT CO.	0.3670	0.3609	0.3550	0.3466	0.3384	18.5156	21.4159
40	KU ENERGY CO.	0.3862	0.3802	0.3743	0.3702	0.3661	23.6305	26.7083
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.5178	0.5110	0.5043	0.4964	0.4886	33.9295	38.0416
42	LONG ISLAND LIGHTING CO.	0.4062	0.3955	0.3851	0.3771	0.3693	14.3596	17.5834
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.3815	0.3757	0.3699	0.3648	0.3598	24.3424	27.3750
44	MINNESOTA POWER & LIGHT CO.	0.4857	0.4840	0.4824	0.4720	0.4619	22.7158	26.5833
45	NEVADA POWER CO.	0.3726	0.3640	0.3557	0.3499	0.3441	17.5427	20.5006
46	NEW ENGLAND ELECTRIC SYSTEM	0.5533	0.5434	0.5337	0.5214	0.5093	27.7101	32.0833
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.5053	0.4937	0.4825	0.4714	0.4607	17.4076	21.4175
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.3459	0.3406	0.3355	0.3312	0.3270	25.7520	28.4999
49	NORTHEAST UTILITIES	0.4246	0.4139	0.4035	0.3921	0.3811	19.5373	22.8750
50	NORTHERN STATES POWER CO.	1.2212	1.1785	1.1373	1.0951	1.0545	33.1665	42.7500
51	OHIO EDISON CO.	0.3523	0.3456	0.3390	0.3327	0.3266	16.3286	19.1250
52	OKLAHOMA GAS & ELECTRIC CO.	0.6173	0.6062	0.5954	0.5866	0.5778	28.3746	33.2914
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.6046	0.5940	0.5835	0.5703	0.5575	25.6655	30.4575
54	PACIFIC GAS & ELECTRIC CO.	0.4771	0.4727	0.4683	0.4544	0.4409	20.0623	23.8333
55	PECO ENERGY	0.3628	0.3574	0.3521	0.3473	0.3425	23.3663	26.2504
56	PENNSYLVANIA POWER & LIGHT CO.	0.3834	0.3732	0.3633	0.3582	0.3532	17.4944	20.5417
57	PORTLAND GENERAL CORP.	0.2718	0.2641	0.2567	0.2556	0.2545	15.3300	17.5000
58	POTOMAC ELECTRIC POWER CO.	0.3836	0.3748	0.3662	0.3603	0.3546	16.9928	20.0416
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.5173	0.5070	0.4970	0.4844	0.4721	23.1660	27.2498
60	PUBLIC SERVICE OF COLORADO	0.4752	0.4697	0.4642	0.4556	0.4472	23.2634	27.0425
61	PUGET SOUND POWER & LIGHT	0.4210	0.4129	0.4049	0.3981	0.3915	16.3116	19.6672
62	ROCHESTER GAS & ELECTRIC CORP.	0.4240	0.4150	0.4062	0.3949	0.3839	18.7855	22.1251
63	SAN DIEGO GAS & ELECTRIC CO.	0.3590	0.3524	0.3459	0.3391	0.3324	16.7788	19.6260
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.6593	0.6468	0.6345	0.6281	0.6217	39.5806	44.8333
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.2346	0.2307	0.2269	0.2233	0.2197	11.4668	13.3333
66	SIERRA PACIFIC RESOURCES	0.2690	0.2654	0.2618	0.2579	0.2540	17.5712	19.7083

Investor Owned Utilities

VG-IBES DGM+

Source: *CRSP; Thomson Financial*

		[22]	[23]	[24]	[25]	[26]	[27]	[28]
		Discounted Projected Dividends					Terminal Price	Q3 1994
	Company	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)	Q2 1996 (DIVT)	(PTERM)	Stock Price
67	SOUTHERN CO	0.2814	0.2773	0.2732	0.2690	0.2649	16.7220	18.9583
68	SOUTHERN INDIANA GAS & ELECTRIC CO	0.3854	0.3777	0.3701	0.3668	0.3635	24.4291	27.4999
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.5091	0.4992	0.4896	0.4819	0.4743	22.4472	26.5000
70	ST. JOSEPH LIGHT & POWER CO	0.4382	0.4410	0.4438	0.4360	0.4283	24.5780	28.0833
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.2435	0.2402	0.2370	0.2337	0.2305	17.7738	19.7083
72	TEXAS UTILITIES CO.	0.7134	0.7077	0.7020	0.6892	0.6767	27.2964	32.9998
73	THE DETROIT EDISON CO.	0.4565	0.4489	0.4414	0.4421	0.4429	22.6919	26.3750
74	THE MONTANA POWER CO.	0.3769	0.3696	0.3624	0.3569	0.3515	20.4228	23.4167
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.2267	0.2465	0.2680	0.2562	0.2448	12.5740	14.4167
76	UNION ELECTRIC CO.	0.5590	0.5433	0.5281	0.5196	0.5112	30.6604	35.0833
77	UNITED ILLUMINATING CO.	0.6502	0.6379	0.6259	0.6118	0.5980	27.0982	32.2500
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.4065	0.4008	0.3952	0.3907	0.3864	25.3435	28.5833
79	WASHINGTON WATER POWER CO.	0.2881	0.2838	0.2795	0.2751	0.2707	12.7450	15.0417
80	WESTERN RESOURCES, INC.	0.4569	0.4491	0.4415	0.4378	0.4342	24.7643	28.4167
81	WISCONSIN ENERGY CORP.	0.3424	0.3380	0.3337	0.3279	0.3222	23.0770	25.7917
82	WISCONSIN PUBLIC SERVICE CORP.	0.4280	0.4220	0.4161	0.4116	0.4071	25.4191	28.8333
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.4600	0.4510	0.4423	0.4334	0.4247	25.1111	28.7500

Investor Owned Utilities

Variable-Growth DGM Model with Thomson Financial Mean 5 Year Earnings Growth Forecast (VG-IBES DGM)+

Notes:

+ The VG-IBES DGM model is discussed in Stewart Myers and Lynda S. Borucki, "Discounted Cash Flow Estimates of the Cost of Equity Capital--A Case Study," Financial Markets, Institutions & Instruments, V. 3, N. 3, August 1994, pp. 9-45.

[1] The average of the end-of-month stock prices reported for Q3 1994.
Source: CRSP.
[2] The projected annual growth in earnings per share for FY 1994.
Source: Thomson Financial.
[3] The projected annual growth in earnings per share for FY 1995.
Source: Thomson Financial.
[4] The implied average annual growth in earnings per share for FY 1996-1998.
Source: Thomson Financial.
[5] The actual dividend paid to shareholders during Q3 1994.
Source: CRSP.
[6] The projected dividends to be paid to shareholders for Q4 1994.
*Formula: (Previous dividend) * (1 + [2])* $^{1/4}$
[7]-[10] The projected dividends to be paid to shareholders for Q1 1995 through Q4 1995.
*Formula: (Previous dividend) * (1 + [3])* $^{1/4}$
[11]-[13] The projected dividend to be paid to shareholders for Q1 1996 through Q3 1996.
*Formula: (Previous dividend) * (1 + [4])* $^{1/4}$
[14] The mean annual forecasted growth rate in earnings per share for the next five years.
Source: Thomson Financial.
[15] The mean forecasted growth rate in earnings per share for the next five years, at a quarterly rate.
Formula: (1 + [14]) $^{1/4}$ *- 1*
[16] The terminal price, or present value of all future dividend streams, at time T.
Formula: [13] / ([17] - [15])
[17] The derived quarterly cost of equity.
Formula: (1 + [18]) $^{1/4}$ *- 1*
[18] The cost of equity, at an annual rate, as predicted by the VG-IBES DGM model.
This is given as the r that solves the following formula.
Formula: [19] + [20] + [21] + [22] + [23] + [24] + [25] + [26] + [27] = [28] = [1]
[19]-[26] The present value of the quarterly dividends paid to shareholders for Q3 1994 through Q2 1996.
The Q3 1994 dividend is paid in the first period, with time (t) = 0.
Note that t=T is the final period.
Formula: (Dividend Paid in Period t) / (1 + [18]) $^{t/4}$
[27] The present value of the terminal stock price.
Formula: [16] / (1 + [18]) $^{T/4}$
[28] The Q3 1994 stock price, given as the sum of the present value of the current and future dividend streams and the present value of the terminal stock price.
This should be equivalent to the reported stock price for the Q3 1994, given at [1].
Formula: [19] + [20] + [21] + [22] + [23] + [24] + [25] + [26] + [27]

Investor Owned Utilities

Variable-Growth Sustainable-Growth DGM Model with Thomson Forecasts (VG-SG DGM)+

Source: *CRSP; Thomson Financial; Value Line*

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
								Nominal Projected Dividends			
	Company	Q3 1994 Stock Price	Thomson Financial 1994 EPS Growth Forecast	Thomson Financial 1995 EPS Growth Forecast	Thomson Financial 1996 -1998 EPS Growth Forecast	Q3 1994 Dividend (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)
1	ALLEGHENY POWER SYSTEM, INC.	21.417	1.53%	3.07%	1.52%	0.4100	0.4116	0.4147	0.4178	0.4210	0.4242
2	AMERICAN ELECTRIC POWER, INC.	31.125	4.12%	0.57%	2.47%	0.6000	0.6061	0.6069	0.6078	0.6087	0.6095
3	ATLANTIC ENERGY, INC.	17.625	-1.30%	-1.69%	3.97%	0.3850	0.3837	0.3821	0.3805	0.3789	0.3773
4	BALTIMORE GAS AND ELECTRIC CO.	22.958	3.87%	3.02%	3.75%	0.3800	0.3836	0.3865	0.3894	0.3923	0.3952
5	BOSTON EDISON CO.	25.667	20.41%	3.44%	-1.84%	0.4400	0.4609	0.4648	0.4688	0.4728	0.4768
6	CAROLINA POWER AND LIGHT	26.458	8.42%	4.40%	0.70%	0.4250	0.4337	0.4384	0.4431	0.4479	0.4527
7	CENTERIOR ENERGY CORP.	9.792	6.77%	7.11%	-1.21%	0.2000	0.2033	0.2068	0.2104	0.2141	0.2178
8	CENTRAL & SOUTH WEST CORP.	22.458	7.27%	1.65%	3.13%	0.4250	0.4325	0.4343	0.4361	0.4379	0.4397
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	25.500	-2.18%	1.47%	4.15%	0.5200	0.5171	0.5190	0.5209	0.5228	0.5248
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	23.000	-14.74%	0.66%	10.77%	0.3650	0.3507	0.3513	0.3519	0.3525	0.3530
11	CENTRAL MAINE POWER CO.	11.500	-30.35%	2.70%	17.46%	0.2250	0.2056	0.2069	0.2083	0.2097	0.2111
12	CENTRAL VERMONT PUBLIC SERVICE CORP	13.417	-11.99%	5.54%	6.36%	0.3550	0.3438	0.3485	0.3532	0.3580	0.3629
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	29.833	6.87%	1.75%	1.74%	0.6150	0.6253	0.6280	0.6307	0.6335	0.6362
14	CINCINNATI GAS & ELECTRIC CO.	22.417	1.37%	1.69%	3.91%	0.4300	0.4315	0.4333	0.4351	0.4369	0.4388
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	27.375	-3.95%	0.28%	8.62%	0.5000	0.4950	0.4953	0.4957	0.4960	0.4964
16	CMS ENERGY CORP.	22.208	11.11%	6.54%	3.18%	0.2100	0.2156	0.2190	0.2225	0.2261	0.2297
17	COMMONWEALTH EDISON CO.	23.333	0.67%	34.17%	-0.25%	0.4000	0.4007	0.4312	0.4641	0.4995	0.5376
18	COMMONWEALTH ENERGY SYSTEM	39.667	-1.03%	-2.02%	6.13%	0.7500	0.7481	0.7442	0.7405	0.7367	0.7329
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	26.958	6.21%	-3.97%	2.93%	0.5000	0.5076	0.5025	0.4974	0.4924	0.4874
20	DELMARVA POWER & LIGHT CO.	18.875	-2.01%	-1.47%	6.33%	0.3850	0.3831	0.3816	0.3802	0.3788	0.3774
21	DOMINION RESOURCES	37.083	1.67%	2.45%	3.53%	0.6350	0.6376	0.6415	0.6454	0.6493	0.6532
22	DPL INC. (DAYTON POWER & LIGHT CO.)	20.042	10.05%	3.66%	2.12%	0.2950	0.3021	0.3049	0.3076	0.3104	0.3132
23	DQE, INC. (DUQUESNE LIGHT CO.)	29.917	6.64%	3.32%	2.75%	0.4200	0.4268	0.4303	0.4338	0.4374	0.4410
24	DUKE POWER CO.	38.667	5.30%	2.33%	3.79%	0.4900	0.4964	0.4992	0.5021	0.5050	0.5080
25	EASTERN UTILITIES ASSOCIATES	24.083	-1.87%	1.43%	6.92%	0.3850	0.3832	0.3846	0.3859	0.3873	0.3887
26	EMPIRE DISTRICT ELECTRIC	16.792	7.76%	9.00%	1.18%	0.3200	0.3260	0.3331	0.3404	0.3478	0.3554
27	ENTERGY CORP.	24.542	-10.43%	3.72%	8.62%	0.4500	0.4378	0.4418	0.4459	0.4499	0.4541
28	FLORIDA PROGRESS CORP.	28.500	6.35%	3.07%	2.20%	0.4950	0.5027	0.5065	0.5103	0.5142	0.5181
29	FPL GROUP, INC.	31.792	4.85%	4.05%	3.79%	0.4200	0.4250	0.4292	0.4335	0.4379	0.4422
30	GENERAL PUBLIC UTILITIES CORP.	25.542	6.34%	1.90%	2.08%	0.4500	0.4570	0.4591	0.4613	0.4635	0.4656
31	GREEN MOUNTAIN POWER CORP.	25.292	-0.11%	1.71%	1.97%	0.5300	0.5298	0.5321	0.5344	0.5366	0.5389
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	31.875	6.17%	7.55%	2.22%	0.5800	0.5888	0.5996	0.6106	0.6218	0.6332
33	HOUSTON INDUSTRIES, INC.	35.042	3.12%	-0.59%	2.59%	0.7500	0.7558	0.7547	0.7535	0.7524	0.7513
34	IDAHO POWER CO.	24.083	-5.08%	9.61%	3.87%	0.4650	0.4590	0.4696	0.4805	0.4917	0.5031
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	26.958	0.66%	2.84%	3.88%	0.5250	0.5259	0.5296	0.5333	0.5370	0.5408
36	INTERSTATE POWER CO.										
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	21.208	4.45%	4.33%	2.36%	0.4325	0.4372	0.4419	0.4466	0.4513	0.4562
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	30.042	0.85%	2.37%	4.92%	0.5300	0.5311	0.5343	0.5374	0.5405	0.5437
39	KANSAS CITY POWER & LIGHT CO.	21.417	9.60%	3.27%	0.29%	0.3800	0.3888	0.3919	0.3951	0.3983	0.4015
40	KU ENERGY CO.	26.708	-2.11%	2.95%	4.88%	0.4100	0.4078	0.4108	0.4138	0.4168	0.4198
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	38.042	5.02%	4.00%	2.94%	0.5375	0.5441	0.5495	0.5549	0.5604	0.5659
42	LONG ISLAND LIGHTING CO	17.583	-3.43%	1.09%	3.40%	0.4450	0.4411	0.4423	0.4435	0.4447	0.4459
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	27.375	3.89%	4.32%	5.00%	0.4000	0.4038	0.4081	0.4125	0.4169	0.4213
44	MINNESOTA POWER & LIGHT CO.	26.583	-1.79%	10.12%	2.38%	0.5050	0.5027	0.5150	0.5275	0.5404	0.5536
45	NEVADA POWER CO.	20.500	0.99%	1.59%	4.33%	0.4000	0.4010	0.4026	0.4041	0.4057	0.4073
46	NEW ENGLAND ELECTRIC SYSTEM	32.083	9.42%	2.75%	0.57%	0.5750	0.5881	0.5921	0.5961	0.6002	0.6043
47	NEW YORK STATE ELECTRIC & GAS CORP.	21.417	-2.15%	4.09%	4.09%	0.5500	0.5470	0.5525	0.5581	0.5637	0.5694
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	28.500	6.03%	3.69%	4.72%	0.3600	0.3653	0.3686	0.3720	0.3754	0.3788
49	NORTHEAST UTILITIES	22.875	18.87%	0.82%	-0.38%	0.4400	0.4594	0.4604	0.4613	0.4623	0.4632
50	NORTHERN STATES POWER CO.	42.750	14.24%	1.71%	0.83%	1.3200	1.3647	1.3705	1.3763	1.3821	1.3880
51	OHIO EDISON CO.	19.125	1.15%	3.07%	3.32%	0.3750	0.3761	0.3789	0.3818	0.3847	0.3876
52	OKLAHOMA GAS & ELECTRIC CO.	33.292	-5.87%	2.10%	3.36%	0.6650	0.6550	0.6584	0.6619	0.6653	0.6688
53	ORANGE & ROCKLAND INDUSTRIES, INC.	30.458	2.78%	4.17%	2.13%	0.6400	0.6444	0.6510	0.6577	0.6645	0.6713
54	PACIFIC GAS & ELECTRIC CO.	23.833	7.57%	6.99%	-1.55%	0.4900	0.4990	0.5075	0.5162	0.5250	0.5339
55	PECO ENERGY	26.250	3.05%	3.66%	4.14%	0.3800	0.3829	0.3863	0.3898	0.3933	0.3969
56	PENNSYLVANIA POWER & LIGHT CO.	20.542	-3.02%	-1.25%	3.95%	0.4175	0.4143	0.4130	0.4117	0.4104	0.4091
57	PORTLAND GENERAL CORP.	17.500	-7.05%	-1.87%	8.07%	0.3000	0.2946	0.2932	0.2918	0.2904	0.2890
58	POTOMAC ELECTRIC POWER CO.	20.042	-2.95%	0.60%	3.52%	0.4150	0.4119	0.4125	0.4131	0.4138	0.4144
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	27.250	9.93%	2.80%	0.44%	0.5400	0.5529	0.5568	0.5606	0.5645	0.5684
60	PUBLIC SERVICE OF COLORADO	27.042	-1.30%	5.20%	2.29%	0.5000	0.4984	0.5047	0.5112	0.5177	0.5243
61	PUGET SOUND POWER & LIGHT	19.667	-8.11%	3.54%	4.67%	0.4600	0.4504	0.4543	0.4583	0.4623	0.4663
62	ROCHESTER GAS & ELECTRIC CORP	22.125	13.25%	1.61%	-1.11%	0.4400	0.4539	0.4557	0.4575	0.4594	0.4612
63	SAN DIEGO GAS & ELECTRIC CO.	19.625	2.32%	2.73%	2.17%	0.3800	0.3822	0.3848	0.3874	0.3900	0.3926
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	44.833	-2.05%	1.73%	5.46%	0.7050	0.7014	0.7044	0.7074	0.7105	0.7135
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	13.333	-2.74%	2.56%	2.80%	0.2500	0.2483	0.2498	0.2514	0.2530	0.2546
66	SIERRA PACIFIC RESOURCES	19.708	4.36%	4.17%	3.55%	0.2800	0.2830	0.2859	0.2888	0.2918	0.2948
67	SOUTHERN CO.	18.958	2.60%	3.80%	3.53%	0.2950	0.2969	0.2997	0.3025	0.3053	0.3082
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	27.500	-1.72%	1.01%	5.73%	0.4125	0.4107	0.4118	0.4128	0.4138	0.4149
69	SOUTHWESTERN PUBLIC SERVICE CO.	26.500	-5.14%	2.13%	3.69%	0.5500	0.5428	0.5457	0.5485	0.5514	0.5544
70	ST. JOSEPH LIGHT & POWER CO.	28.083	-6.57%	12.16%	1.84%	0.4500	0.4424	0.4553	0.4686	0.4822	0.4962
71	TECO ENERGY INC. (TAMPA ELECTRIC)	19.708	6.14%	4.22%	4.10%	0.2525	0.2563	0.2590	0.2616	0.2644	0.2671

Investor Owned Utilities

Variable-Growth Sustainable-Growth DGM Model with Thomson Forecasts (VG-SG DGM)+

Source: *CRSP; Thomson Financial; Value Line*

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
								Nominal Projected Dividends			
	Company	Q3 1994 Stock Price	Thomson Financial 1994 EPS Growth Forecast	Thomson Financial 1995 EPS Growth Forecast	Thomson Financial 1996 -1998 EPS Growth Forecast	Q3 1994 Dividend (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)
72	TEXAS UTILITIES CO.	33.000	-11.30%	9.22%	4.84%	0.7700	0.7473	0.7639	0.7810	0.7984	0.8162
73	THE DETROIT EDISON CO.	26.375	-22.08%	3.13%	11.06%	0.5150	0.4839	0.4876	0.4914	0.4952	0.4990
74	THE MONTANA POWER CO.	23.417	2.77%	2.93%	4.76%	0.4000	0.4027	0.4057	0.4086	0.4116	0.4145
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	14.417	-3.79%	58.93%	-5.10%	0.2000	0.1981	0.2224	0.2497	0.2804	0.3148
76	UNION ELECTRIC CO.	35.083	7.79%	-1.59%	3.33%	0.5950	0.6063	0.6039	0.6014	0.5990	0.5967
77	UNITED ILLUMINATING CO.	32.250	3.73%	4.77%	3.17%	0.6900	0.6963	0.7045	0.7128	0.7211	0.7296
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	28.583	0.20%	5.96%	7.17%	0.4300	0.4302	0.4365	0.4428	0.4493	0.4558
79	WASHINGTON WATER POWER CO.	15.042	-6.33%	4.61%	4.34%	0.3100	0.3050	0.3084	0.3119	0.3155	0.3190
80	WESTERN RESOURCES, INC.	28.417	-7.73%	3.33%	7.08%	0.4950	0.4851	0.4891	0.4932	0.4972	0.5013
81	WISCONSIN ENERGY CORP.	25.792	8.77%	4.79%	2.82%	0.3525	0.3600	0.3642	0.3685	0.3728	0.3772
82	WISCONSIN PUBLIC SERVICE CORP	28.833	-4.08%	3.38%	4.70%	0.4550	0.4503	0.4540	0.4578	0.4616	0.4655
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	28.750	8.46%	1.58%	1.36%	0.4800	0.4898	0.4918	0.4937	0.4956	0.4976

Investor Owned Utilities

VG-SG DGM+

Source: CRSP; Thomson Financial; Value Line

		[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]
		Nominal Projected Dividends			Qtrly Sustainable Growth Rate	Terminal Price	Quarterly Cost	VG-SG	Discounted Projected Dividends		
	Company	Q1 1996 (DIV7)	Q2 1996 (DIVT)	Q3 1996 (DIVT+1)	(GTERM)	(PTERM)	of Equity	DGM ROE	Q3 1994 (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)
1	ALLEGHENY POWER SYSTEM, INC.	0.4258	0.4274	0.4290	0.6519%	21.9693	2.60%	10.83%	0.4100	0.4011	0.3939
2	AMERICAN ELECTRIC POWER, INC.	0.6132	0.6170	0.6208	0.6423%	31.8914	2.59%	10.76%	0.6000	0.5908	0.5767
3	ATLANTIC ENERGY. INC.	0.3810	0.3847	0.3884	0.6252%	17.9924	2.78%	11.61%	0.3850	0.3734	0.3617
4	BALTIMORE GAS AND ELECTRIC CO.	0.3989	0.4025	0.4063	0.7961%	23.8737	2.50%	10.37%	0.3800	0.3743	0.3679
5	BOSTON EDISON CO.	0.4746	0.4724	0.4702	0.7006%	26.4031	2.48%	10.30%	0.4400	0.4498	0.4426
6	CAROLINA POWER AND LIGHT	0.4535	0.4543	0.4551	0.5520%	27.0506	2.23%	9.24%	0.4250	0.4242	0.4194
7	CENTERIOR ENERGY CORP.	0.2171	0.2164	0.2158	0.9427%	10.2139	3.06%	12.79%	0.2000	0.1973	0.1947
8	CENTRAL & SOUTH WEST CORP.	0.4431	0.4465	0.4499	0.6806%	23.1008	2.63%	10.94%	0.4250	0.4214	0.4123
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.5301	0.5355	0.5410	0.5667%	26.0190	2.65%	11.01%	0.5200	0.5038	0.4926
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.3622	0.3716	0.3812	0.6675%	23.8156	2.27%	9.39%	0.3650	0.3430	0.3359
11	CENTRAL MAINE POWER CO.	0.2198	0.2288	0.2382	0.6046%	11.8921	2.61%	10.84%	0.2250	0.2003	0.1965
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.3685	0.3743	0.3801	0.4089%	13.5411	3.22%	13.50%	0.3550	0.3331	0.3271
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.6390	0.6418	0.6445	0.5327%	30.3098	2.66%	11.07%	0.6150	0.6091	0.5959
14	CINCINNATI GAS & ELECTRIC CO.	0.4430	0.4472	0.4516	0.9503%	23.4699	2.87%	12.00%	0.4300	0.4194	0.4094
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.5067	0.5173	0.5281	0.5930%	28.1132	2.47%	10.26%	0.5000	0.4830	0.4717
16	CMS ENERGY CORP.	0.2315	0.2333	0.2351	1.7234%	24.7515	2.67%	11.13%	0.2100	0.2100	0.2078
17	COMMONWEALTH EDISON CO.	0.5373	0.5369	0.5366	0.6294%	24.2185	2.84%	11.87%	0.4000	0.3896	0.4077
18	COMMONWEALTH ENERGY SYSTEM	0.7439	0.7551	0.7664	0.8317%	41.2255	2.69%	11.21%	0.7500	0.7285	0.7058
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.4910	0.4945	0.4981	0.7071%	27.7129	2.50%	10.40%	0.5000	0.4952	0.4782
20	DELMARVA POWER & LIGHT CO.	0.3833	0.3892	0.3952	0.3634%	19.0146	2.44%	10.13%	0.3850	0.3739	0.3637
21	DOMINION RESOURCES	0.6589	0.6647	0.6705	0.7370%	38.3772	2.48%	10.31%	0.6350	0.6222	0.6108
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.3149	0.3165	0.3182	0.8451%	20.9295	2.37%	9.80%	0.2950	0.2952	0.2909
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.4440	0.4470	0.4500	0.9362%	31.4603	2.37%	9.81%	0.4200	0.4169	0.4106
24	DUKE POWER CO.	0.5127	0.5175	0.5223	1.0060%	40.9198	2.28%	9.45%	0.4900	0.4853	0.4772
25	EASTERN UTILITIES ASSOCIATES	0.3952	0.4019	0.4087	1.0713%	25.5474	2.67%	11.12%	0.3850	0.3732	0.3648
26	EMPIRE DISTRICT ELECTRIC	0.3564	0.3575	0.3585	0.6062%	17.2180	2.69%	11.20%	0.3200	0.3175	0.3159
27	ENTERGY CORP.	0.4636	0.4732	0.4831	0.5590%	25.1849	2.48%	10.28%	0.4500	0.4272	0.4207
28	FLORIDA PROGRESS CORP.	0.5209	0.5238	0.5266	0.7868%	29.5618	2.57%	10.68%	0.4950	0.4901	0.4814
29	FPL GROUP, INC.	0.4464	0.4505	0.4547	0.9645%	33.5514	2.32%	9.61%	0.4200	0.4154	0.4100
30	GENERAL PUBLIC UTILITIES CORP.	0.4680	0.4705	0.4729	0.7506%	26.4088	2.54%	10.56%	0.4500	0.4456	0.4366
31	GREEN MOUNTAIN POWER CORP.	0.5415	0.5442	0.5469	0.4784%	25.6015	2.61%	10.88%	0.5300	0.5163	0.5053
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.6367	0.6402	0.6437	0.6411%	32.7892	2.60%	10.83%	0.5800	0.5738	0.5695
33	HOUSTON INDUSTRIES, INC.	0.7561	0.7610	0.7658	0.8276%	36.2324	2.94%	12.29%	0.7500	0.7342	0.7121
34	IDAHO POWER CO	0.5079	0.5127	0.5176	0.4210%	24.4572	2.54%	10.54%	0.4650	0.4476	0.4467
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.5460	0.5512	0.5565	0.8187%	27.9928	2.81%	11.71%	0.5250	0.5115	0.5010
36	INTERSTATE POWER CO.										
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.4588	0.4615	0.4642	0.6682%	21.7785	2.80%	11.68%	0.4325	0.4253	0.4181
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.5503	0.5570	0.5637	0.8229%	31.2777	2.63%	10.92%	0.5300	0.5175	0.5073
39	KANSAS CITY POWER & LIGHT CO.	0.4018	0.4021	0.4024	0.6475%	21.9754	2.48%	10.29%	0.3800	0.3794	0.3732
40	KU ENERGY CO.	0.4249	0.4300	0.4351	0.8448%	27.9143	2.40%	9.97%	0.4100	0.3982	0.3917
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.5700	0.5741	0.5783	0.8741%	39.8521	2.33%	9.63%	0.5375	0.5318	0.5248
42	LONG ISLAND LIGHTING CO.	0.4497	0.4535	0.4573	0.2639%	17.5004	2.88%	12.01%	0.4450	0.4288	0.4179
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.4265	0.4317	0.4370	1.3500%	29.6087	2.83%	11.79%	0.4000	0.3927	0.3860
44	MINNESOTA POWER & LIGHT CO.	0.5568	0.5601	0.5634	0.6047%	27.2956	2.67%	11.11%	0.5050	0.4897	0.4886
45	NEVADA POWER CO.	0.4117	0.4161	0.4205	0.8352%	21.3037	2.81%	11.72%	0.4000	0.3900	0.3809
46	NEW ENGLAND ELECTRIC SYSTEM	0.6052	0.6060	0.6069	0.6673%	32.9562	2.51%	10.42%	0.5750	0.5737	0.5635
47	NEW YORK STATE ELECTRIC & GAS CORP.	0.5751	0.5809	0.5868	0.5008%	21.6839	3.21%	13.46%	0.5500	0.5300	0.5187
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.3832	0.3876	0.3921	1.2897%	30.7580	2.56%	10.66%	0.3600	0.3562	0.3504
49	NORTHEAST UTILITIES	0.4628	0.4623	0.4619	0.9669%	23.8807	2.90%	12.12%	0.4400	0.4465	0.4348
50	NORTHERN STATES POWER CO.	1.3908	1.3937	1.3966	0.7587%	43.5131	3.97%	16.84%	1.3200	1.3126	1.2678
51	OHIO EDISON CO.	0.3908	0.3940	0.3972	0.7234%	19.7288	2.74%	11.41%	0.3750	0.3661	0.3590
52	OKLAHOMA GAS & ELECTRIC CO.	0.6744	0.6800	0.6856	0.5416%	33.9155	2.56%	10.65%	0.6650	0.6387	0.6259
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.6748	0.6784	0.6820	0.5302%	30.9751	2.73%	11.38%	0.6400	0.6273	0.6169
54	PACIFIC GAS & ELECTRIC CO.	0.5318	0.5298	0.5277	0.7701%	24.5754	2.92%	12.19%	0.4900	0.4849	0.4792
55	PECO ENERGY	0.4009	0.4050	0.4091	1.1132%	27.9407	2.58%	10.72%	0.3800	0.3732	0.3671
56	PENNSYLVANIA POWER & LIGHT CO.	0.4131	0.4171	0.4212	0.6952%	21.1027	2.69%	11.21%	0.4175	0.4035	0.3916
57	PORTLAND GENERAL CORP.	0.2947	0.3005	0.3064	0.7703%	18.1729	2.46%	10.19%	0.3000	0.2875	0.2793
58	POTOMAC ELECTRIC POWER CO.	0.4180	0.4216	0.4253	0.5207%	20.3630	2.61%	10.85%	0.4150	0.4014	0.3918
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.5690	0.5696	0.5703	0.6188%	27.8442	2.67%	11.10%	0.5400	0.5386	0.5282
60	PUBLIC SERVICE OF COLORADO	0.5272	0.5302	0.5332	0.7706%	28.0142	2.67%	11.13%	0.5000	0.4854	0.4788
61	PUGET SOUND POWER & LIGHT	0.4717	0.4771	0.4826	0.7201%	20.2362	3.10%	13.01%	0.4600	0.4368	0.4274
62	ROCHESTER GAS & ELECTRIC CORP.	0.4599	0.4587	0.4574	0.6220%	22.5683	2.65%	11.02%	0.4400	0.4422	0.4325
63	SAN DIEGO GAS & ELECTRIC CO.	0.3947	0.3968	0.3990	0.9404%	20.5114	2.89%	12.05%	0.3800	0.3715	0.3635
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.7231	0.7327	0.7425	1.2219%	48.0017	2.77%	11.54%	0.7050	0.6825	0.6669
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.2564	0.2582	0.2600	0.8150%	13.8384	2.69%	11.22%	0.2500	0.2418	0.2369
66	SIERRA PACIFIC RESOURCES	0.2974	0.3000	0.3026	0.6381%	20.3360	2.13%	8.78%	0.2800	0.2771	0.2741
67	SOUTHERN CO.	0.3109	0.3136	0.3163	0.7802%	19.7163	2.38%	9.88%	0.2950	0.2900	0.2859
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.4207	0.4266	0.4326	0.8278%	28.7145	2.33%	9.67%	0.4125	0.4013	0.3932
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.5594	0.5645	0.5696	0.6686%	27.2043	2.76%	11.52%	0.5500	0.5282	0.5167
70	ST. JOSEPH LIGHT & POWER CO	0.4985	0.5008	0.5031	0.2504%	28.2599	2.03%	8.37%	0.4500	0.4336	0.4374
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.2698	0.2725	0.2753	1.6606%	21.7873	2.92%	12.22%	0.2525	0.2490	0.2444

Investor Owned Utilities

VG-SG DGM+

Source. CRSP; Thomson Financial. Value Line

		[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]
		Nominal Projected Dividends			Qtrly Sustainable Growth Rate	Terminal Price	Quarterly Cost	VG-SG	Discounted Projected Dividends		
	Company	Q1 1996 (DIV7)	Q2 1996 (DIVT)	Q3 1996 (DIVT+1)	(GTERM)	(PTERM)	of Equity	DGM ROE	Q3 1994 (DIV1)	Q4 1994 (DIV2)	Q1 1995 (DIV3)
72	TEXAS UTILITIES CO.	0.8259	0.8357	0.8456	0.2232%	33.0186	2.78%	11.61%	0.7700	0.7270	0.7231
73	THE DETROIT EDISON CO.	0.5122	0.5259	0.5398	0.6681%	27.2705	2.65%	11.02%	0.5150	0.4714	0.4628
74	THE MONTANA POWER CO.	0.4194	0.4243	0.4292	0.8412%	24.4258	2.60%	10.81%	0.4000	0.3925	0.3854
75	TNP ENTERPRISES INC. (TEXAS-NEW MEXICO POWER CO.)	0.3107	0.3067	0.3027	-0.9300%	13.6063	1.29%	5.28%	0.2000	0.1955	0.2168
76	UNION ELECTRIC CO.	0.6016	0.6065	0.6115	0.4982%	35.6904	2.21%	9.14%	0.5950	0.5932	0.5780
77	UNITED ILLUMINATING CO.	0.7353	0.7411	0.7469	0.4835%	32.7283	2.77%	11.53%	0.6900	0.6776	0.6671
78	UTILICORP UNITED INC. (MISSOURI PUBLIC SERVICE)	0.4638	0.4719	0.4802	1.3852%	31.0314	2.93%	12.26%	0.4300	0.4180	0.4120
79	WASHINGTON WATER POWER CO.	0.3224	0.3259	0.3294	0.6758%	15.4781	2.80%	11.70%	0.3100	0.2967	0.2918
80	WESTERN RESOURCES, INC.	0.5099	0.5187	0.5277	0.6134%	29.2485	2.42%	10.03%	0.4950	0.4737	0.4663
81	WISCONSIN ENERGY CORP	0.3799	0.3825	0.3852	1.1224%	27.4808	2.52%	10.48%	0.3525	0.3511	0.3465
82	WISCONSIN PUBLIC SERVICE CORP.	0.4709	0.4763	0.4818	0.7044%	29.8495	2.32%	9.60%	0.4550	0.4401	0.4337
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.4993	0.5010	0.5027	0.8359%	29.9023	2.52%	10.45%	0.4800	0.4778	0.4679

Summary Statistics:	Mean =	10.92%
	Median =	10.90%
	Min =	5.28%
	Max =	16.84%

Investor Owned Utilities

VG-SG DGM+

Source: CRSP; Thomson Financial; Value Line

		[21]	[22]	[23]	[24]	[25]	[26]	[27]
		Discounted Projected Dividends					Terminal Price	Q3 1994
	Company	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)	Q2 1996 (DIVT)	(PTERM)	Stock Price
1	ALLEGHENY POWER SYSTEM, INC.	0.3868	0.3799	0.3730	0.3649	0.3570	18.3504	21.4171
2	AMERICAN ELECTRIC POWER, INC.	0.5629	0.5495	0.5364	0.5261	0.5159	26.6670	31.1254
3	ATLANTIC ENERGY, INC.	0.3504	0.3395	0.3289	0.3231	0.3174	14.8459	17.6252
4	BALTIMORE GAS AND ELECTRIC CO.	0.3616	0.3554	0.3493	0.3440	0.3387	20.0871	22.9582
5	BOSTON EDISON CO.	0.4356	0.4286	0.4218	0.4097	0.3979	22.2404	25.6662
6	CAROLINA POWER AND LIGHT	0.4147	0.4100	0.4054	0.3972	0.3892	23.1737	26.4588
7	CENTERIOR ENERGY CORP.	0.1922	0.1898	0.1873	0.1812	0.1753	8.2736	9.7916
8	CENTRAL & SOUTH WEST CORP.	0.4034	0.3947	0.3862	0.3792	0.3723	19.2644	22.4590
9	CENTRAL HUDSON GAS & ELECTRIC CORP.	0.4817	0.4710	0.4605	0.4532	0.4461	21.6719	25.5008
10	CENTRAL LOUISIANA ELECTRIC CO., INC.	0.3290	0.3222	0.3156	0.3166	0.3176	20.3555	23.0003
11	CENTRAL MAINE POWER CO.	0.1928	0.1892	0.1856	0.1883	0.1911	9.9313	11.5002
12	CENTRAL VERMONT PUBLIC SERVICE CORP.	0.3212	0.3155	0.3098	0.3048	0.2999	10.8500	13.4164
13	CILCORP INC. (CENTRAL ILLINOIS LIGHT CO.)	0.5830	0.5703	0.5580	0.5459	0.5341	25.2230	29.8343
14	CINCINNATI GAS & ELECTRIC CO.	0.3996	0.3901	0.3808	0.3737	0.3668	19.2470	22.4168
15	CIPSCO (CENTRAL ILLINOIS PUBLIC SERVICE CO.)	0.4607	0.4499	0.4393	0.4377	0.4360	23.6966	27.3750
16	CMS ENERGY CORP.	0.2056	0.2034	0.2013	0.1976	0.1940	20.5777	22.2074
17	COMMONWEALTH EDISON CO.	0.4266	0.4465	0.4672	0.4540	0.4412	19.9006	23.3334
18	COMMONWEALTH ENERGY SYSTEM	0.6838	0.6625	0.6418	0.6344	0.6270	34.2331	39.6667
19	CONSOLIDATED EDISON CO. OF NEW YORK, INC.	0.4618	0.4460	0.4307	0.4232	0.4159	23.3068	26.9579
20	DELMARVA POWER & LIGHT CO.	0.3537	0.3440	0.3345	0.3316	0.3287	16.0598	18.8750
21	DOMINION RESOURCES	0.5996	0.5886	0.5778	0.5687	0.5598	32.3205	37.0830
22	DPL INC. (DAYTON POWER & LIGHT CO.)	0.2868	0.2827	0.2787	0.2737	0.2687	17.7700	20.0417
23	DQE, INC. (DUQUESNE LIGHT CO.)	0.4044	0.3983	0.3923	0.3858	0.3795	26.7088	29.9167
24	DUKE POWER CO.	0.4693	0.4614	0.4537	0.4478	0.4419	34.9401	38.6667
25	EASTERN UTILITIES ASSOCIATES	0.3566	0.3485	0.3407	0.3374	0.3342	21.2430	24.0833
26	EMPIRE DISTRICT ELECTRIC	0.3143	0.3128	0.3112	0.3040	0.2969	14.2999	16.7925
27	ENTERGY CORP.	0.4143	0.4080	0.4018	0.4003	0.3987	21.2201	24.5410
28	FLORIDA PROGRESS CORP.	0.4730	0.4646	0.4564	0.4474	0.4386	24.7538	28.5003
29	FPL GROUP, INC.	0.4047	0.3995	0.3943	0.3890	0.3837	28.5754	31.7920
30	GENERAL PUBLIC UTILITIES CORP.	0.4278	0.4192	0.4107	0.4026	0.3947	22.1544	25.5417
31	GREEN MOUNTAIN POWER CORP.	0.4945	0.4840	0.4737	0.4638	0.4542	21.3701	25.2920
32	HAWAIIAN ELECTRIC INDUSTRIES, INC.	0.5652	0.5610	0.5568	0.5457	0.5347	27.3887	31.8756
33	HOUSTON INDUSTRIES, INC.	0.6908	0.6700	0.6499	0.6354	0.6212	29.5780	35.0417
34	IDAHO POWER CO.	0.4457	0.4448	0.4438	0.4370	0.4302	20.5225	24.0834
35	IES INDUSTRIES (IOWA ELECTRIC & IOWA SOUTHERN)	0.4908	0.4807	0.4709	0.4624	0.4541	23.0622	26.9587
36	INTERSTATE POWER CO.							
37	IOWA-ILLINOIS GAS & ELECTRIC CO.	0.4111	0.4042	0.3973	0.3888	0.3804	17.9508	21.2085
38	IPALCO ENTERPRISES, INC. (INDIANAPOLIS POWER & LIGHT)	0.4972	0.4873	0.4777	0.4711	0.4646	26.0891	30.0417
39	KANSAS CITY POWER & LIGHT CO.	0.3671	0.3611	0.3552	0.3469	0.3388	18.5143	21.4161
40	KU ENERGY CO.	0.3853	0.3790	0.3728	0.3684	0.3641	23.6386	26.7083
41	LG&E ENERGY CORP. (LOUISVILLE GAS & ELECTRIC CO.)	0.5179	0.5111	0.5044	0.4966	0.4888	33.9290	38.0419
42	LONG ISLAND LIGHTING CO.	0.4074	0.3970	0.3870	0.3793	0.3718	14.3491	17.5833
43	MDU RESOURCES GROUP (MONTANA-DAKOTA UTILITIES CO.)	0.3794	0.3729	0.3665	0.3608	0.3552	24.3615	27.3750
44	MINNESOTA POWER & LIGHT CO.	0.4875	0.4864	0.4853	0.4754	0.4658	22.6998	26.5833
45	NEVADA POWER CO.	0.3719	0.3632	0.3546	0.3486	0.3427	17.5483	20.5003
46	NEW ENGLAND ELECTRIC SYSTEM	0.5534	0.5436	0.5339	0.5216	0.5095	27.7083	32.0824
47	NEW YORK STATE ELECTRIC & GAS CORP	0.5077	0.4968	0.4863	0.4759	0.4657	17.3853	21.4165
48	NIPSCO INDUSTRIES (NORTHERN INDIANA PUBLIC SERVICE CO.)	0.3448	0.3392	0.3337	0.3292	0.3247	25.7618	28.5000
49	NORTHEAST UTILITIES	0.4234	0.4123	0.4015	0.3898	0.3784	19.5484	22.8751
50	NORTHERN STATES POWER CO.	1.2246	1.1829	1.1425	1.1012	1.0614	33.1370	42.7500
51	OHIO EDISON CO.	0.3521	0.3453	0.3387	0.3323	0.3261	16.3312	19.1258
52	OKLAHOMA GAS & ELECTRIC CO.	0.6135	0.6013	0.5893	0.5793	0.5696	28.4092	33.2918
53	ORANGE & ROCKLAND INDUSTRIES, INC.	0.6066	0.5966	0.5867	0.5741	0.5618	25.6492	30.4590
54	PACIFIC GAS & ELECTRIC CO.	0.4735	0.4679	0.4624	0.4476	0.4332	20.0947	23.8334
55	PECO ENERGY	0.3611	0.3552	0.3494	0.3441	0.3389	23.3817	26.2509
56	PENNSYLVANIA POWER & LIGHT CO.	0.3802	0.3690	0.3582	0.3523	0.3464	17.5230	20.5417
57	PORTLAND GENERAL CORP.	0.2713	0.2635	0.2560	0.2548	0.2535	15.3340	17.5000
58	POTOMAC ELECTRIC POWER CO.	0.3824	0.3732	0.3643	0.3581	0.3521	17.0036	20.0420
59	PUBLIC SERVICE ENTERPRISE GROUP, INC.	0.5180	0.5081	0.4983	0.4859	0.4738	23.1591	27.2500
60	PUBLIC SERVICE OF COLORADO	0.4722	0.4658	0.4595	0.4500	0.4408	23.2891	27.0417
61	PUGET SOUND POWER & LIGHT	0.4181	0.4091	0.4002	0.3926	0.3852	16.3373	19.6666
62	ROCHESTER GAS & ELECTRIC CORP.	0.4230	0.4138	0.4047	0.3932	0.3820	18.7944	22.1258
63	SAN DIEGO GAS & ELECTRIC CO.	0.3557	0.3480	0.3406	0.3328	0.3252	16.8079	19.6251
64	SCANA CORP. (SOUTH CAROLINA ELECTRIC & GAS CO.)	0.6518	0.6369	0.6224	0.6138	0.6052	39.6488	44.8333
65	SCE CORP (SOUTHERN CALIF. EDISON CORP.)	0.2322	0.2275	0.2229	0.2186	0.2143	11.4891	13.3333
66	SIERRA PACIFIC RESOURCES	0.2712	0.2683	0.2654	0.2621	0.2589	17.5512	19.7083
67	SOUTHERN CO.	0.2818	0.2779	0.2739	0.2699	0.2659	16.7180	18.9583
68	SOUTHERN INDIANA GAS & ELECTRIC CO.	0.3852	0.3773	0.3697	0.3663	0.3630	24.4316	27.5001
69	SOUTHWESTERN PUBLIC SERVICE CO.	0.5055	0.4945	0.4838	0.4750	0.4665	22.4799	26.5000
70	ST. JOSEPH LIGHT & POWER CO.	0.4411	0.4449	0.4488	0.4419	0.4350	24.5505	28.0832
71	TECO ENERGY INC. (TAMPA ELECTRIC)	0.2400	0.2356	0.2313	0.2270	0.2227	17.8067	19.7092

Investor Owned Utilities

VG-SG DGM+

Source: CRSP; Thomson Financial; Value Line

		[21]	[22]	[23]	[24]	[25]	[26]	[27]
		Discounted Projected Dividends					Terminal Price	Q3 1994
	Company	Q2 1995 (DIV4)	Q3 1995 (DIV5)	Q4 1995 (DIV6)	Q1 1996 (DIV7)	Q2 1996 (DIVT)	(PTERM)	Stock Price
72	TEXAS UTILITIES CO.	0.7192	0.7153	0.7115	0.7004	0.6895	27.2441	33.0001
73	THE DETROIT EDISON CO.	0.4543	0.4460	0.4379	0.4379	0.4379	22.7118	26.3750
74	THE MONTANA POWER CO.	0.3783	0.3714	0.3646	0.3595	0.3545	20.4109	23.4173
75	TNP ENTERPRISES, INC. (TEXAS-NEW MEXICO POWER CO.)	0.2403	0.2663	0.2952	0.2876	0.2803	12.4347	14.4166
76	UNION ELECTRIC CO.	0.5632	0.5489	0.5348	0.5276	0.5204	30.6232	35.0843
77	UNITED ILLUMINATING CO.	0.6568	0.6466	0.6366	0.6243	0.6122	27.0392	32.2503
78	UTILICORP UNITED, INC. (MISSOURI PUBLIC SERVICE)	0.4061	0.4002	0.3945	0.3900	0.3855	25.3474	28.5835
79	WASHINGTON WATER POWER CO.	0.2871	0.2824	0.2778	0.2732	0.2685	12.7542	15.0418
80	WESTERN RESOURCES, INC.	0.4590	0.4519	0.4448	0.4418	0.4388	24.7448	28.4163
81	WISCONSIN ENERGY CORP.	0.3420	0.3375	0.3330	0.3271	0.3213	23.0808	25.7917
82	WISCONSIN PUBLIC SERVICE CORP.	0.4274	0.4212	0.4151	0.4104	0.4057	25.4249	28.8334
83	WPL HOLDINGS, INC. (WISCONSIN POWER & LIGHT)	0.4582	0.4487	0.4394	0.4301	0.4210	25.1268	28.7500

Investor Owned Utilities

Variable-Growth Sustainable-Growth DGM Model with Value Line Forecasts (VG-SG DGM)+

Notes:

+ The VG-SG DGM model is discussed in Stewart Myers and Lynda S. Borucki, "Discounted Cash Flow Estimates of the Cost of Equity Capital--A Case Study," Financial Markets, Institutions & Instruments, V. 3, N. 3, August 1994, pp. 9-45.

[1] The average of the end-of-month stock prices reported for Q3 1994.
Source: CRSP.
[2] The projected annual growth in earnings per share for FY 1994.
Source: Thomson Financial.
[3] The projected annual growth in earnings per share for FY 1995.
Source: Thomson Financial.
[4] The implied average annual growth in earnings per share for FY 1996-1998.
Source: Thomson Financial.
[5] The actual dividend paid to shareholders during Q3 1994.
Source: CRSP.
[6] The projected dividends to be paid to shareholders for Q4 1994.
Formula: $(\text{Previous dividend}) * (1 + [2])^{1/4}$
[7]-[10] The projected dividends to be paid to shareholders for Q1 1995 through Q4 1995.
Formula: $(\text{Previous dividend}) * (1 + [3])^{1/4}$
[11]-[13] The projected dividend to be paid to shareholders for Q1 1996 through Q3 1996.
Formula: $(\text{Previous dividend}) * (1 + [4])^{1/4}$
[14] The long-term quarterly sustainable growth rate of earnings per share (from the CG-SG DGM model).
Source: CG-SG DGM model, column [14].
[15] The terminal price, or present value of all future dividend streams, at time T.
Formula: $[13] / ([16] - [14])$
[16] The derived quarterly cost of equity.
Formula: $(1 + [17])^{1/4} - 1$
[17] The cost of equity, at an annual rate, as predicted by the VG-SG DGM model.
This is given as the r that solves the following formula.
Formula: $[18] + [19] + [20] + [21] + [22] + [23] + [24] + [25] + [26] = [27] = [1]$
[18]-[25] The present value of the quarterly dividends paid to shareholders for Q3 1994 through Q2 1996.
The Q3 1994 dividend is paid in the first period, with time (t) = 0.
Note that t=T is the final period.
Formula: $(\text{Dividend Paid in Period } t) / (1 + [17])^{t/4}$
[26] The present value of the terminal stock price.
Formula: $[15] / (1 + [17])^{T/4}$
[27] The Q3 1994 stock price, given as the sum of the present value of the current and future dividend streams and the present value of the terminal stock price.
This should be equivalent to the reported stock price for Q3 1994, given at [1].
Formula: $[18] + [19] + [20] + [21] + [22] + [23] + [24] + [25] + [26]$

Summary of Authorized Return on Equity for Staff Utility Sample[1]

Source: Regulatory Research Associates, *Regulatory Focus & Major Rate Case Decisions*

Company	State	Authorized Return on Equity[2]	Year Authorized
Allegheny Power System, Inc.	PA, WV, MD, VA, OH	11.36% [3]	1993-1994
American Electric Power, Inc.	VA, WV, KY, OH, IN, MI, TN	11.70% [4]	1991-1994
Atlantic Energy, Inc.	NJ		
Baltimore Gas & Electric Co.	MD	11.75% [5]	1993
Boston Edison Co.	MA	11.75% [6]	1992
Carolina Power and Light	NC, SC	12.75% [7]	1988
Centerior Energy Corp.	OH		
Central & South West Corp.	TX, OK, LA, AR		
Central Hudson Gas & Electric Corp.	NY	10.60% [8]	1993
Central Louisiana Electric Co., Inc.	LA		
Central Maine Power Co.	ME	10.55% [9]	1993
Central Vermont Public Service Corp.	VT, NH	10.00% [10]	1994
CILCORP Inc. (Central Illinois Light Co.)	IL	16.00% [11]	1982
Cincinnati Gas & Electric Co.	OH, KY, IN	12.05% [12]	1993
CIPSCO (Central Illinois Public Service Co.)	IL	12.28% [13]	1992
CMS Energy Corp.	MI	11.75% [14]	1994
Commonwealth Edison Co.	IL	13.00% [15]	1991
Commonwealth Energy System	MA	12.00% [16]	1991
Consolidated Edison Co. of New York, Inc.	NY	10.90% [17]	1994
Delmarva Power & Light Co.	DE, MD, VA	11.50% [18]	1994
Dominion Resources	VA, NC	11.40% [19]	1994
DPL Inc. (Dayton Power & Light Co.)	OH	13.00% [20]	1992
DQE, Inc. (Duquesne Light Co.)	PA	12.87% [21]	1988
Duke Power Co.	NC, SC	12.38% [22]	1991
Eastern Utilities Associates	MA, RI		
Empire District Electric	MO, KS, OK, AR		
Entergy Corp.	AR, LA, MS, MO, TX	10.98% [23]	1994
Florida Progress Corp.	FL		
FPL Group, Inc.	FL	12.00% [24]	1993
General Public Utilities Corp.	PA, NJ	12.20% [25]	1993
Green Mountain Power Corp.	VT	10.50% [26]	1994
Hawaiian Electric Industries, Inc.	HI	12.15% [27]	1994
Houston Industries, Inc.	TX		
Idaho Power Co.	ID, NV, OR	11.00% [28]	1995
IES Industries (Iowa Electric & Iowa Southern)	IA		
Interstate Power Co.	IA, MN, IL	10.95% [29]	1992-1994
Iowa-Illinois Gas & Electric Co.	IA, IL	11.32% [30]	1993-1994
IPALCO Enterprises, Inc. (Indiannapolis Power & Light)	IN	13.50% [31]	1986
Kansas City Power & Light Co.	MO, KS	13.50% [32]	1986-1987
KU Energy Co.	KY, VA		
LG&E Energy Corp. (Louisville Gas & Electric Co.)	KY	12.50% [33]	1990
Long Island Lighting Co.	NY	10.10% [34]	1993
MDU Resources Group (Montana-Dakota Utilities Co.)	MT, ND, SD, WY	12.30% [35]	1987
Minnesota Power & Light Co,	MN, WI	11.60% [36]	1994

Summary of Authorized Return on Equity for Staff Utility Sample[1]

Source: Regulatory Research Associates, *Regulatory Focus & Major Rate Case Decisions*

Company	State	Authorized Return on Equity[2]	Year Authorized
Nevada Power Co.	NV	12.50% [37]	1992
New England Electric System	MA, RI, NH		
New York State Electric & Gas Corp.	NY	10.80% [38]	1993
NIPSCO Indistries (Northern Indiana Public Service Co.)	IN	13.50% [39]	1987
Northeast Utilities	CT, NH, MA	15.00% [40]	1987
Northern States Power Co.	MN, WI, ND, SD, MI	11.56% [41]	1993
Ohio Edison Co.	OH, PA	13.21% [42]	1990
Oklahoma Gas & Electric Co.	OK, AR	12.00% [43]	1994
Orange & Rockland Industries, Inc.	NY, PA, NJ	10.40% [44]	1990
Pacific Gas & Electric Co.	CA	12.10% [45]	1994
PECO Energy	PA	12.75% [46]	1990
Pennsylvania Power & Light Co.	PA		
Portland General Corp.	OR	11.60% [47]	1995
Potomac Electric Power Co.	DC, MD	11.88% [48]	1991-1994
Public Service Enterprise Group, Inc.	NJ		
Public Service of Colorado	CO, WY	11.00% [49]	1993
Puget Sound Power & Light	WA	10.50% [50]	1993
Rochester Gas & Electric Corp.	NY	11.50% [51]	1993
San Diego Gas & Electric Co.	CA	12.05% [52]	1994
SCANA Corp. (South Carolina Electric & Gas Co.)	SC	11.50% [53]	1993
SCE Corp (Southern Calif. Edison Corp.)	CA	12.10% [54]	1994
Sierra Pacific Resources	NV, CA	11.50% [55]	1993
Southern Co.	GA, AL, FL, MS	12.16% [56]	1990-1994
Southern Indiana Gas & Electric Co.	IN		
Southwestern Public Service Co.	TX, NM, OK, KS	16.17% [57]	1982
St. Joseph Light & Power Co.	MO	11.67% [58]	1993
TECO Energy Inc. (Tampa Electric)	FL	12.45% [59]	1994
Texas Utilities Co.	TX		
The Detroit Edison Co.	MI	11.00% [60]	1994
The Montana Power Co.	MT	11.00% [61]	1994
TNP Enterprises, Inc. (Texas-New Mexico Power Co.)	TX, NM	13.16% [62]	1992
Union Electric Co.	MO, IL	15.62% [63]	1985
United Illuminating Co.	CT	12.40% [64]	1992
Utilicorp United, Inc. (Missouri Public Service)	MO, KS, MN, IA, CO, WV, NE, MI, Canada, British Columbia, New Zealand	12.84% [65]	1990
Washington Power Co.	WA, ID		
Western Resources, Inc.	KS, MO, OK		
Wisconsin Energy Corp.	WI, MI	12.30% [66]	1993
Wisconsin Public Service Corp.	WI, MI	11.50% [67]	1994
WPL Holdings, Inc. (Wisconsin Power & Light)	WI	11.50% [68]	1994
Min		10.00%	
Max		16.17%	

Summary of Authorized Return on Equity for Staff Utility Sample[1]

Source: Regulatory Research Associates, *Regulatory Focus & Major Rate Case Decisions*

[1] Illinova Corp., Northwestern Public Service, Pinnacle West, Tucson Electric Power, El Paso Electric Co., Midwest Resources, Otter Tail Power, Niagara Mohawk Power, Pacificorp, PSI Resources, and Public Service Co. of New Mexico are not included in this sample because they were dropped by the Staff.

[2] Authorized ROE are the decisions that are in effect as of March 1995 as recorded in the Regulatory Research Associates Major Rate Decisions Report.

[3] Average of all ROEs authorized to Allegheny Power by different states (listed below):

11.5% issued in Pennsylvania on 12/15/94.

10.85% issued in West Virginia on 11/9/94 to Monongahela Power, which is now Allegheny Power.

11.9% issued in Maryland on 2/24/93.

11.2% issued in Virginia on 11/18/94.

[4] Average of all ROEs authorized to American Electric Power by different states (listed below):

11.4% issued in Virginia on 6/27/94.

12% issued in West Virginia on 11/1/91.

[5] Authorized in Maryland on 4/23/93.

[6] Authorized in Massachusetts on 10/30/92.

[7] The last major ROE decision was issued in 1988 in North Carolina and South Carolina.

[8] Authorized in New York on 12/16/93.

[9] Authorized in Maine on 12/14/93. A five-year ARP was adopted on 1/10/95, whereby earnings outside a 700-basis-point deadband around a target ROE (initially set at 10.55%) are shared equally by shareholders and ratepayers.

[10] Authorized in Vermont on 10/31/94 after 75-basis-point penalty for mismanagement of power purchase contracts. Penalty subsequently was suspended in Docket No 5863.

[11] The last major electric decision was issued 7/1/82, at which time a 16% ROE was established. Electric restructuring legislation enacted in 1997, required a 2% residential rate reduction to be implemented 8/1/98. Earnings are subject to an ROE cap based on the U.S. Treasury Bond yield. On 8/25/99, the ICC established delivery service tariffs (DSTs) based on a 10.52% ROE. Updated DSTs adopted 3/28/02 based on an 11.02%

[12] Authorized in Ohio on 8/26/93. Parties agreed to an 11.4% - 12.7% ROE range.

[13] Authorized in Illinois on 3/18/92. On 8/25/99, the ICC established unbundled DSTs based on a 10.45% ROE. Updated DSTs were adopted 12/11/01 based on an 11.35% ROE.

[14] Authorized in Michigan on 5/10/94 for Consumers Energy, the principal subsidiary of CMS Energy.

[15] Authorized in Illinois on 3/8/91.

[16] Authorized in Massachusetts on 7/1/91.

[17] Authorized in New York on 9/29/94.

[18] Authorized in Delaware on 10/18/94.

[19] Authorized in Virginia on 2/3/94.

[20] Authorized in Ohio on 1/22/92.

[21] Last major ROE decision issued 3/25/88, at which time a 12.87% ROE was established.

[22] Average of all ROEs authorized to Duke Power by different states (listed below):

12.25% issued in South Carolina on 11/5/91.

12.5% issued in North Carolina on 11/12/91.

[23] Average of all ROEs authorized to Entergy by different states (listed below):

10.95% Authorized in Louisiana on 12/14/94 for Entergy Gulf States.

11% Authorized in Mississippi on 3/1/94 for Entergy Mississippi.

[24] On 7/6/93, PSC adopted a stipulation reducing authorized ROE for all regulatory purposes to 12%, the mid-point of an 11% to 13% range.

[25] Authorized in New Jersey on 2/26/93 for Jersey Central Power & Light, a division of GPU Energy, which is now a subsidiary of FirstEnergy. (Formal order was issued 6/15/93).

[26] Authorized in Vermont on 5/13/94.

[27] Authorized in Hawaii on 12/28/94.

[28] Authorized in Idaho on 1/31/95.

[29] Average of all ROEs authorized to Interstate Power by different states (listed below):

11% Authorized in Iowa on 6/3/94.

10.9% Authorized in Minnesota on 6/12/92.

[30] Average of all ROEs authorized to Iowa-Illinois Gas & Electric by different states (listed below):

11.25% Authorized in Iowa on 2/25/94.

11.38% Authorized in Illinois on 7/21/93.

Summary of Authorized Return on Equity for Staff Utility Sample[1]

Source: Regulatory Research Associates, *Regulatory Focus & Major Rate Case Decisions*

[31] Last authorized ROE was established in Indiana in 8/86.

[32] Average of all ROEs authorized to Kansas City Power & Light by different states (listed below):
15% the last major ROE decision issued in Missouri on 4/23/86.
12% the last major ROE decision issued in Kansas on 7/8/87.

[33] Authorized in Kentucky on 12/21/90.

[34] Authorized in New York on 12/23/93.

[35] Last major rate decision in Montana was issued 7/2/84. 12.3% ROE established for electric division in a small case decided 12/1/87.

[36] Authorized in Minnesota on 11/22/94.

[37] Authorized in Nevada on 8/6/92.

[38] Authorized in New York on 11/2/93.

[39] Last authorized ROE was established in Indiana in 7/15/87.

[40] Last major ROE decision issued 6/29/87 in New Hampshire to Public Service N.H., which merged with Northeast Utilities.

[41] Average of all ROEs authorized to Northern States Power by different states (listed below):
11.47% issued in Minnesota on 9/29/93.
12% issued in Wisconsin on 1/12/93.
Order on reconsideration issued in North Dakota on 4/7/93 permitting an additional $2.1 million increase and raising the authorized ROE to 11.5%.
Two-step hike sought and authorized in South Dakota, effective in 1993. Neither the stipulation nor the order specify an allowed ROE; however, it appears that an 11.25% ROE was relied upon by the parties.

[42] Authorized in Ohio on 8/16/90.

[43] Authorized in Oklahoma on 2/25/94.

[44] Authorized in New York on 9/26/90.

[45] On 11/22/94, PUC adopted 12.1% ROE for attrition year 1995.

[46] Authorized in Pennsylvania on 4/19/90.

[47] Authorized in Oregon on 3/29/95.

[48] Average of all ROEs authorized to Potomac Electric Power by different states (listed below):
11% issued in DC on 3/4/94.
12.75% issued in Maryland on 5/30/91.

[49] Authorized in Colorado on 11/26/93.

[50] Authorized in Washington on 9/21/93.

[51] Authorized in New York on 8/24/93.

[52] On 11/22/94, PUC adopted 12.05% ROE.

[53] Authorized in South Carolina on 5/25/93.

[54] 12.1% ROE established 11/22/94 for attrition year 1995.

[55] Authorized in Nevada on 6/7/93.

[56] Average of all ROEs authorized to Southern Co. by different states (listed below):
12.25% issued in Georgia on 9/30/91 to Georgia Power.
ROE range of 13-14.5%, with an adjusting point of 13.75% for Alabama Power.
(Established 3/5/90 and most recently extended 6/12/95).
10.07% issued in Mississippi on 1/4/94 to Mississippi Power.
12.55% issued in Florida on 8/10/90 to Gulf Power.

[57] Last major ROE decision issued in Texas on 6/23/82.

[58] Authorized in Missouri on 6/25/93 for Aquila-SJL&P, which formerly did business as St. Joseph Light &

[59] ROE was capped at 12.45% for calendar year 1994 by PSC vote on 7/5/94.

[60] Authorized in Michigan on 1/21/94.

[61] Authorized in Montana on 4/25/94 to North Western Energy, which is the former distribution and transmission utility assets of Montana Power.

[62] Authorized in Texas on 10/16/92.

[63] Last ROE was authorized on 5/8/85 to Ameren UE, which was formerly Union Electric.

[64] Authorized in Connecticut on 12/16/92.

[65] Authorized in Missouri on 10/5/90.

[66] Authorized in Wisconsin on 2/15/93.

[67] Authorized in Wisconsin on 12/19/94.

[68] Authorized in Wisconsin on 12/8/94.

UE-88 REMAND / PGE EXHIBIT / 6700
HESS

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

The Risk Premium

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alan C. Hess, Ph.D

February 15, 2005

I. Introduction

Q. Please state your name and qualifications.

A. My name is Alan C. Hess. I am a professor of finance and business economics in the University of Washington Business School. My qualifications appear at the end of this testimony. I have written and consulted extensively in the areas of finance, commercial damages, copyright infringement, and commercial banking.

Q. What is the purpose of your testimony?

A. I provide an analysis of the effects on a regulated utility's cost of capital when it is not able to earn a return on plant and equipment that has been retired prior to the end of the asset's depreciation life. I show the equity risk premium that a rational investor would require to continue investing in a regulated utility whose assets are subject to default risk. Default risk in this case relates to the ability of PGE investors to earn a rate of return on the unamortized investment in Trojan. I discuss why adequate compensation of investor risk is necessary in meeting customers' demands and decommissioning risk and its applicability to utilities is modeled to show that required ROE increases with increased risk.

Q. Can you describe the capital attraction function of a regulated electric utility?

A. Yes. The production and distribution of electricity in a growing economy requires continual maintenance, upgrading, replacement, and enlargement of the plant and equipment that produces and distributes the electricity. An investor-owned public utility finances its ongoing physical plant improvements internally from its operating cash flows, and externally via borrowing and issuing equity.

Q. What is the role of investors in providing investment capital?

A. Investors, who buy the utility's bonds and stocks, are willing to provide funds to the utility only if they expect to receive a return on their financing that compensates them for the rate of return they would have received on an alternative use of their funds that has the same risk as an investment in the utility.

Q. What is the role of a Public Utility Commission (PUC) in capital attraction?

A. Public utility commissions attempt to set the rates that a regulated utility can charge its customers at levels that allows the utility to convince investors that they will be competitively compensated for buying the utility's debt and equity.

Q. What if the PUC does not set rates sufficient to assure investors that they will be competitively compensated?

A. Investors will not provide sufficient financing to the utility for it to have the wherewithal to meet its customers' electricity demands. The opportunity-cost based rate of return that investors expect to receive is the utility's cost of capital.

Q. What tools does a PUC have to determine a fair rate of return for equity investors?

A. There are several financial tools that a PUC could use, such as the Discounted Cash Flow (DCF) or Capital Asset Pricing Model (CAPM). I base my discussion on CAPM because its formulation allows for explicit recognition of factors important to this proceeding. The CAPM formula relates the cost of equity capital, k_e, to the risk free interest rate, r_f, the contribution of the utility's payoff to the risk of a well-diversified portfolio, β, and to the equity risk premium per unit of risk that investors require, λ. The CAPM formula is:

$$k_e = r_f + \beta \cdot \lambda . \quad (1)$$

Q. Please summarize how the CAPM formula works?

A. Investors require compensation equal to the rate they would have earned on a risk free assets, such as a default-free U.S. Treasury security, plus a risk premium that is the product of the utility's risk as measured by its beta, β, times lambda, λ, the risk premium that investors require for each unit of risk they bear.

Q. Does the CAPM formula take into account enterprise default risk?

A. No. The CAPM serves as a framework to discuss the cost of equity capital for an ongoing business. It does not include a component for an abrupt end to the business. The CAPM estimate may be thought of as the expected rate of return to bearing business and financial risk but not default risk.

Q. Does the CAPM assumption of no default risk apply to a regulated utility?

A. This assumption of a going enterprise may not hold for a regulated utility whose revenues are based in part on their capital equipment being in use.

Q. Why is it that the traditional CAPM formula may not apply to a regulated utility?

A. If the utility takes some of its capital stock out of use, it may not be able to charge its customers a rate of return on the decommissioned plant and equipment. In the event of plant and equipment decommissioning, the CAPM-based rate of return that investors expected to receive on their investment in the securities that funded the plant is replaced with a rate of return of zero.

Q. If an equity investor knows he is at risk of not receiving a return on a portion of his investment, how could he be compensated?

A. Before they buy a utility's equities, rational investors should anticipate that the utility may decommission some of its plant and terminate the associated rate of return revenue. If so,

investors will require an extra risk premium before they buy the utility's securities to compensate them for the potential loss of their rate of return. This premium has been formally established for corporate bonds.[1] A similar analysis can be applied to equity.

Q. What investment choices does an equity investor have?

A. An investor has a choice between buying equity in a rate-regulated, investor-owned utility, or in another company or portfolio of companies that has the same risk. If the investor buys shares in another company or companies his expected payoff can be represented using the CAPM as $(1+r_f+\beta\lambda)$. If instead, the investor buys equity in a rate-regulated utility, his expected payoff depends on whether the utility keeps the plant and equipment in use.

Q. Please describe how asset impairment risk can be quantified from an investor perspective.

A. Let p be the probability that the utility will decommission some of its plant and equipment before it has generated sufficient revenues to compensate investors for the opportunity cost of their investment in the utility's securities. If this occurs, investors get back their investment but they do not continue to receive a rate of return on their investment. The expected payoff per dollar invested in the event of plant decommissioning is p.

Q. Please describe the risk premium equity investors require associated with this asset impairment risk.

A. Investors know before they invest that the utility may decommission some of its plant and equipment, which reduces the cash flow it has available to pay to investors. Rational investors require an additional risk premium to compensate them for the reduced cash flow

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[1] Darrell Duffie and Kenneth J. Singleton, "Modeling Term Structures of Defaultable Bonds," *The Review of Financial Studies* Special 1999 Vol. 12, No.4, pp. 687-720.

they suffer in the event of decommissioning. Let δ be the decommissioning risk premium. With probability *(1-p)*, the utility will continue to operate the plant and equipment. If the utility does not decommission any of its plant and equipment, the expected return to investors is $(1-p)(1+rf+\beta\lambda+\delta)$. The cost of capital for the ongoing plant and equipment must be increased by δ to compensate investors for the chance of decommissioning.

Q. What equity return does an investor require where this asset impairment risk exists?

A. The expected payoff to an investor for every dollar invested in the utility's equity is:

$$p \cdot 1 + (1-p) \cdot (1 + r_f + \beta \cdot \lambda + \delta). \qquad (2)$$

In this payoff to equity equation, the one stands for the amount of the investment. A rational investor requires that two investments of equal risk have equal expected rates of return. For the regulated public utility that cannot earn a return on its decommissioned plant and equipment, this equal-rate-of-return condition is

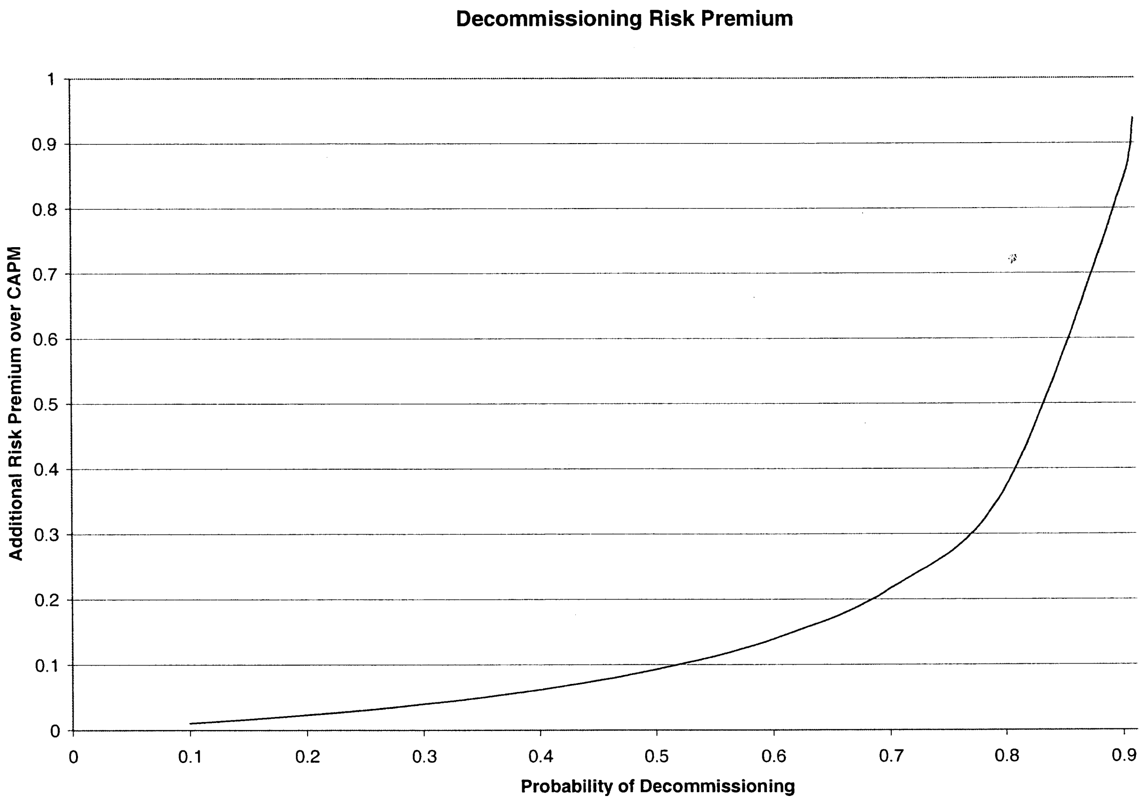
$$1 + r_f + \beta \cdot \lambda = p \cdot 1 + (1-p) \cdot (1 + r_f + \beta \cdot \lambda + \delta). \qquad (3)$$

The left-hand-side is the expected rate of return on an alternative investment with systematic, ongoing risk equal to the systematic, ongoing risk of the utility. The right-hand-side is the expected rate of return on a rate-regulated utility that loses some of its cash flow when it decommissions plant and equipment.

The equal-rate-rate-of-return condition can be rearranged to express the required size of the decommissioning risk premium as:

$$\delta = (1-p)^{-1}(1 + r_f + \beta \cdot \lambda - p) - (1 + r_f + \beta \cdot \lambda). \qquad (4)$$

The decommissioning risk premium depends on the probability that the utility will decommission some of its plant and equipment, the risk-free interest rate, the utility's systematic risk, and the equity premium.



Q. Please give an example of how this risk premium formula can be applied to a utility.

A. The figure above plots the decommissioning risk premium against the probability that the utility will decommission some of its plant and equipment and give up the return on its decommissioned facilities.[2] This figure shows a plot of equation (4) for representative values of the risk-free rate, which is set at 4% in line with the rate on 10-year Treasury bonds in December 2004, a beta of 0.8, an equity premium of 6.6%, which is the difference between

[2] The data in the chart are for illustrative purposes to show how the decommissioning risk premium varies with the probability of decommissioning.

the average annual rate of return on the S&P 500 index and the 10 year Treasury rate for the years 1926-2003, and probabilities of decommissioning ranging from 0.1 to 0.91.

Q. Please describe the implications to a regulated utility and its equity investors of the foregoing graph.

A. Increases in the utility's probability of decommissioning increases the decommissioning risk premium that investors require to own the utility's stock. The only place the investor can look for this expected return is from the utility's cash flows if it keeps the plant and equipment in use. They must receive greater expected cash flows from the utility's ongoing operations to compensate them for the possibility of decreased cash flow in the event of plant and equipment decommissioning. Once the utility decommissions the plant and equipment, its cash flow decreases and it has less money available to pay to its shareholders. As a result, the cost of capital for ongoing plant and equipment is higher for a rate-regulated utility that forfeits the return on its investment in plant and equipment that is not in use.

Q. Please summarize your testimony.

A. The CAPM gives the expected rate of return on an investment in an ongoing business that does not have a truncated return distribution. A rate-regulated utility may not be permitted to earn a return on plant and equipment that is not in use. This truncates its return distribution. To be willing to buy shares in a rate-regulated utility, rational investors require an additional risk premium above the CAPM risk premium. This premium compensates them for the possible loss of future returns from investing in a utility that subsequently decommissions some of its plant and equipment. This decommissioning risk premium depends on the components of the CAPM and the probability that the utility will decommission some of its

plant and equipment. The decommissioning risk premium increases with the probability of decommissioning.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
6701	Witness Qualifications

ALAN C. HESS

Alan Hess is an Academic Affiliate of ERS Group and Professor of Finance and Business Economics in the University of Washington Business School. He holds M.S. and Ph.D. degrees in economics from Carnegie Mellon University and a B.S. in industrial management from Purdue University.

Professor Hess's academic and consulting interests encompass both economics and finance. He has conducted studies of:

- Banks, savings and loans, credit unions, insurance companies, factors and investment banks.
- Damages arising from trademark and patent infringement, antitrust, and commercial disputes.
- Event studies of the effects of public announcements on stock prices.
- The valuation of residential and commercial real estate including the effects of alternative financing techniques and environmental restrictions.
- The management of risks using derivative financial instruments including futures and securitized assets.
- The valuation of public utilities.
- The costs and benefits of highway construction projects.

Professor Hess has served in the Federal Reserve System and at the Securities and Exchange Commission. He has won numerous teaching awards including the University of Washington's Distinguished Teaching Award; the M.B.A. Association's Distinguished Professor Award, the Executive MBA Program's Excellence in Teaching Award, the Burlington Northern Distinguished Teaching Award, and the Wells Fargo Outstanding Teaching Award.

EDUCATION

1969	Ph.D. in Economics	Carnegie Mellon University, Pittsburgh, PA
1967	M.S. in Economics	Carnegie Mellon University, Pittsburgh, PA
1963	B.S. in Industrial Management (with distinction, economics honors)	Purdue University, West Lafayette, IN

EMPLOYMENT HISTORY

September 1996 to present	Co-Founder and Principal KeyPoint Consulting LLC, now ERS Group
1967 – present	Assistant, Associate and Professor of Finance and Business Economics , University of Washington
Autumn 1997	Visiting Professor of Finance University of California at Berkeley
Spring 1992	Visiting Scholar, Universidad Nova de Lisboa
Spring 1986	Visiting Professor of Finance Graduate School of Business, University of Chicago
Autumn 1983	Visiting Professor of Finance Graduate School of Business, University of Chicago
Autumn 1982	Visiting Scholar Federal Reserve Bank of Kansas City
Academic year 1977 - 1978	Visiting Associate Professor College of Business, University of Maryland
Academic years 1976 – 1978	Economic Fellow Securities and Exchange Commission, Washington, D.C.
Autumn 1976	Visiting Associate Professor of Economics Virginia Polytechnic Institute and State University
Autumn 1973	Visiting Associate Professor of Economics Department of Economics, University of Virginia
September 1965- August 1967	Economic Fellow Federal Reserve Bank of Cleveland
June 1963 - July 1964	General Electric Computer Department Financial Management

LITIGATION AND BUSINESS CONSULTING EXPERIENCE

ANTITRUST

UltraHue v. Xerox. Analyzed the degree of competition in the market for color laser printers. Assessed whether Xerox has market power in the sale of solid ink sticks. Deposition testimony pursuant to a case filed in United States District Court, Western District of Washington at Seattle.

BANKING AND FINANCIAL INTERMEDIARIES

Served as an expert witness for Recreational Equipment and US Bank in a lawsuit involving an auction sale of a credit card portfolio. Deposition testimony.

Helped defend Associates Financial Services Company against a charge that it violated Montana law in dealing with sub-prime borrowers.

Testified in Guam court about the differences among bank lending agreements, letters of credit, and loan guarantees.

Testified in federal court regarding the nature of and international markets for standby letters of credit.

Advised Bank of America, which was a senior lender on a non-performing loan, on its financial responsibilities to a subordinated lender to the same borrower.

Evaluated the financial performance of KeyBank of Idaho relative to its peers for the purpose of assessing the importance of reducing personnel and occupancy expenses. Deposition testimony.

Testified before the Washington state senate regarding the financial health of WSCUGA, a private credit union insurer, the economic bases for private insurance of credit unions, and the effects of proposed changes in the insurance system on credit union members and the insurer.

Assessed the accuracy of assertions by a dismissed examiner that the Federal Home Loan Bank of Seattle was neglect in its oversight of the risk management activities of a federally insured bank.
Assessed the accuracy of assertions by regulators that Benj. Franklin Savings was taking undue risks before it failed. Examined the effects on risks and returns of regulators requiring the bank to sell offsetting pieces of the derivative portfolio at

different times.

Analyzed the financial effects on First Interstate Bank of Washington of alternative strategies for disposing of a portfolio of mortgages acquired as part of a government assisted takeover of a failed savings bank.

Advised First Interstate Bank of Washington on the incremental cash flows and net present value of a proposed new computer system.

Advised the board of directors of Telco credit union on actions to overcome short-run problems, and recommended changes in performance evaluation and monitoring procedures to improve long-run performance.

Estimated damages to a factor from early termination of a factoring contract by a startup manufacturer. Testified in superior court.

Helped defend the Washington state Director of Banking against a charge that he conspired with a failing bank to deny continued credit to a developer who was in arrears on a loan.

Analyzed the effects of F.I.R.R.E.A on the financial performance of the 5th 3rd Bank.

Analyzed the effects of F.I.R.R.E.A. on the financial performance of Benj. Franklin Savings Bank.

Analyzed the effects of F.I.R.R.E.A. on the financial performance of D&N Bank.

Adviser to Seattle City Employees' Pension Fund. Help evaluate performance, choose asset allocations, and select managers.

COMMERCIAL DAMAGES

ATT v. GTE. Estimated damages to a supplier of business telephone services due to alleged false advertising by a competitor.

Advised a leveraged buyout firm on the price they should pay for a pulp and paper mill. Constructed pro forma financial statements, estimated the cost of capital, and estimated the discounted cash flow value of the company.

Qualcomm v. Ericsson. Estimated damages to a cellular telephone design and manufacturing company due to unfair business practices by a competitor. Included an event study of the effects of each company's product announcements on the other company's stock price.

Strobe Data v. Digital Equipment. Estimated damages to an integrated software and hardware design firm resulting from an alleged breach of contract by a supplier of a critical component. Deposition and testimony in federal court.

Estimated damages to a recycling processor due to a breach of contract by one of its waste suppliers.

Estimated the economic damages to Reinell, a boat manufacturer, of contaminated resin used in the production process. Testified in federal court.

RSR v. AIU Insurance. Helped defend AIU against a charge that its alleged nonpayment of environmental cleanup costs affected the cost of capital of an insured lead recycler.

Analyzed the effects of the stock market and an earthquake on the financial performance of a high-end retail furniture store.

PATENT AND COPYRIGHT INFRINGEMENT

CipherTrust v. IronPort. Evaluated damages to an inbound email appliance company due to alleged trademark infringement. Estimated plaintiff's lost profits, defendant's unjust enrichment, reasonable royalty, and corrective advertising damages. Deposition testimony.

Mackie v. Behringer. Estimated damages to an audio mixer manufacturer from alleged trademark and trade dress infringement. Deposition testimony.

CyberMedia v. Symantec. Estimated damages to a software company from its loss of market share caused by a competitor using many lines of identical code in a widely distributed utility.

Estimated damages to an inventor of medical devices due to alleged patent infringement by St. Jude Medical.

Chamberlin v. Overhead Door. Estimated damages to an electronic garage door opener company due to alleged patent infringement by a competitor.

PUBLIC UTILITY CONSULTING

U.S. West New Vector. Used statistical transfer functions to estimate consumers' demands for cellular service. Paid special attention to estimating price elasticities.

Williams' Gas Pipeline division. Estimated the cost of equity capital, the cash-based rate of return on new projects, the cash-based rate of return on existing projects, the cash-based regulatory rate of return, and economic value added for Williams.

U.S. West. Analyzed the financial consequences of defeasing bonds. Made presentation to board of directors supporting defeasance.

W.I.T.A. v. Pacific County P.U.D. # 2. Analyzed the possible economies to a public utility from being a retail Internet service provider. Deposition testimony.

Built and implemented a discounted cash flow model of public utilities with holdings in the State of Washington for the purpose of assessing their values for *ad valorem* taxes.

REAL ESTATE CONSULTING

Fluke Capital. Analyzed the effects on the city of Bellevue, Washington's tax revenues and convention business of a shortage of hotel rooms due to environmental regulations preventing construction of a city-approved hotel.

SECURITIES LITIGATION

Conducted an event study of the effects of Nortel's earnings announcements on its stock price.

Conducted an event study of the effects of Southeastern Bancorp's earnings announcements on its stock price.

Conducted a "fraud-on-the-market" study of alleged improper conduct by Asia Pulp & Paper.

VALUATION

Analyzed the financial performance of Saber pursuant to a charge that its rates were sufficiently high that it earned monopoly profits.

Reviewed three consultants' valuations of a privately held company. Assessed accuracy of discounted cash flows, capitalized earnings, and adjusted book values.

Reconciled different estimates.

Appraised 50.2% of the stock in a closely held investment company for estate tax purposes.

CONSULTING FOR GOVERNMENTS

Washington State Legislative Transportation Committee. Conducted a cost and benefit analysis of several major transportation projects in a heavily congested section of Seattle beset by traffic conflicts between trucks, trains, cars, bicycles, pedestrians, sports events, port shipping, and ferry traffic.

Bumbershoot. Built a financial model of Bumbershoot, a Seattle city-sponsored festival, from the perspective of making it a stand-alone, private enterprise. Estimated the amount of equity needed to finance the venture.

Estimated the costs to King County, Washington of extra police officer and clerical staff time required by an unfunded mandate from the Washington state legislature governing required police responses to domestic violence calls. Deposition testimony.

Projected changes to state-chartered credit unions' financial performances if the Washington State legislature subjects them to the Business and Occupation tax.

RESEARCH PAPERS

"Are the Major Japanese Banks Uniform or Unique?" With Kathryn Dewenter and Yasushi Hamao. Presented at the NBER/CEPR/CIRJE/EIJS Japan Project Meeting, Tokyo, September 2004.

"Are Relationship and Transactional Banks Different? Evidence from Loan Loss Provisions and Write-Offs." With Kathryn Dewenter. Presented at the Financial Intermediation Research Society conference, Capri, Italy, May 2004. Presented at the European Financial Management Association conference, Basle June 2004.

"Conditional Time-Varying Interest Rate Risk Premium: Evidence from the Treasury Bill Futures Market." With Avraham Kamara. Forthcoming, *Journal of Money, Credit and Banking.*

" Risks and Returns in Relationship and Transactional Banks: Evidence from Banks' Returns in Germany, Japan, the U.K., and the U.S.," (with K. Dewenter), Cambridge University Press, 1999.

"An International Comparison of Banks' Equity Returns," (with K. Dewenter),

Journal of Money, Credit, and Banking, August 1998.

"A Market-Based Risk Classification of Financial Institutions," (with K. Laisathit), *Journal of Financial Services Research,* December 1997. One of the ten most frequently downloaded papers on the Financial Economics Network.

"Portfolio Theory, Transaction Costs, and the Demand for Time Deposits," *Journal of Money, Credit, and Banking,* November 1995

"The Term Premium: Default, Liquidity and Interest Rate Risk," (with A. Kamara), abstract in *Journal of Finance,* Vol. 50, No. 3, July 1995, pp. 979-980

"Do Regulated Utilities Have Growth Opportunities?" *Assessment Journal,* July/August 1995

"Elements of Mortgage Securitization," (with C. Smith), Reprinted in *Studies in Financial Institutions: Commercial Banks,* C.M. James and C.W. Smith, eds., McGraw-Hill, 1994

" The Effects of Transaction Costs on Households' Financial Asset Demands," *Journal of Money, Credit, and Banking,* August 1991

"Elements of Mortgage Securitization," (with C. Smith), *Journal of Real Estate Finance and Economics,* 1988

"Could Thrifts Be Profitable? Theoretical and Empirical Evidence," *Carnegie-Rochester Conference Series on Public Policy,* Spring 1987

"The Intermediation Profit Margin: A New Measure of Savings and Loan Association Financial Performance," Center for the Study of Banking and Financial Markets *Digest,* Winter 1987

"Size Effects of Seasoned Stock Issues: Empirical Evidence," (with S. Bhagat), *Journal of Business,* October 1986

"Discount Mortgage Financing and Housing Prices," (with P.A. Malatesta), *Housing Finance Review,* Summer 1986

"Comment on Quantification of Selected Elements of Non-Standard Financing which Are Only Partially Capitalized," *Property Tax Journal,* December 1985

"Discount Mortgage Financing and House Prices," (with P.A. Malatesta), Center for the Study of Banking and Financial Markets *Digest,* Winter 1985

"Introduction to Duration," Washington Credit Union League *Investment Guide,* 1984

"Asset and Liability Management Strategies," Center for the Study of Banking and Financial Markets *Digest,* Summer 1984

"Variable Rate Mortgages: Confusion of Means and Ends," *Financial Analysts*

Journal, January/February 1984

"Lease Rates on Washington State Aquatic Lands: Some Economic Considerations," *Western Tax Review,* Fall 1983

Abstract of "Tests for Price Effects of New Issues of Seasoned Securities," (with P. Frost), *The CFA Digest,* Winter 1983

Contribution to *Monetarism and the Federal Reserve's Conduct of Monetary Policy,* Subcommittee on Monetary and Fiscal Policy, Joint Economic Committee, U.S. Congress, December 1982

Review of *Setting National Priorities: The 1982 Budget* and *The Economy: Is this a Change in Direction? Journal of Money, Credit and Ranking,* November 1982

Duration Analysis for Savings and Loan Associations," *Federal Home Loan Bank Board Journal,* October 1982

"Tests for Price Effects of New Issues of Seasoned Securities," (with P. Frost), *Journal of Finance,* March 1982

A Brief History of the School and Graduate School of Business Administration of the University of Washington: The Hanson Years 1964-1981, editor, 1981

"Simulation of Skin Diseases for Teaching Dermatological Diagnosis," (with J.M. Short, M.D.), *Journal of Medical Education,* April 1980

"The Riskless Rate of Interest and the Market Price of Risk: Correction," *Quarterly Journal of Economics,* November 1978

"A Comparison of Automobile Demand Equations," *Econometrica,* April 1977

"Household Response to a Money Rain: Real and Portfolio Balance Effects Reconsidered," *Journal of Monetary Economics,* January 1977

"The Riskless Rate or Interest and the Market Price of Risk," *Quarterly Journal of Economics,* August 1975

"Household Demand for Durable Goods: The Influence of Rates of Return and Wealth," *Review of Economics and Statistics,* February 1973

"Experimental Evidence on Price Formation in Competitive Markets," *Journal of Political Economy,* March/April 1972

"The Money Supply Process," *Journal of Finance,* September 1971

"An Explanation of Short-Run Fluctuations in the Ratio of Currency to Demand Deposits," *Journal of Money, Credit, and Banking,* August 1971

"A Quantity Theory Approach to the Current Inflation," *Washington Business Review,* Summer 1969

"A Note on Supplemental Appropriations in the Federal Budgetary Process," (with G.W. Bowman, O.A. Davis, and H.S. Gailliot), *Papers on Non-Market Decision Making,* January 1967

ACADEMIC TEACHING

Financial markets and institutions
International finance
Banking
Microeconomics
Monetary economics
Macroeconomics

PROFESSIONAL TEACHING

SEAFIRST CORPORATE FINANCE SEMINAR
Present lectures and lead discussion on causes and consequences of interest rate risk; topics include calling and defeasing bonds, swaps, securitization, and monetary and fiscal policies

BANK OF AMERICA, MARKET RISK MANAGEMENT SEMINAR
Present lectures and lead discussion on factors affecting the level and structure of interest rates, duration, and immunization

BOEING COMMERCIAL AIRPLANE CO., SALES FINANCIAL TRAINING SEMINAR
Analysis of the sources of changes in the level and structure of interest rates and their implications for airplane financing

CHASE MANHATTAN BANK, ADVANCED PRODUCT SEMINAR
Present lectures and lead discussion on factors affecting the level and structure of interest rates, duration, and immunization

PACIFIC COAST BANKING SCHOOL
Present lectures to U.S. bankers on the workings of U.S. financial markets, their relationship to economic activity, and their effects on banks' financial performances. Present lectures and lead discussions on managing interest rate and foreign exchange rate risks using forwards, futures, swaps, options, and securitized assets.

BANKING AND SOCIETY IN AMERICA
Teach regional bankers from Japan about the Federal Reserve System and U.S. financial markets

KOREAN BANKERS PROGRAM
Present lectures to Korean bankers covering the structure and working of U.S. financial markets and the Federal Reserve System

MANAGEMENT PROGRAM, SCHOOL OF BUSINESS, UNIVERSITY OF WASHINGTON
Present lectures on monetary and fiscal policy and quantitative analysis of business decisions

SCHOOL OF EXECUTIVE DEVELOPMENT, THE INSTITUTE OF FINANCIAL EDUCATION
Activities include teaching savings and loan association executives the principles of financial management of financial institutions plus administering their playing of the Stanford Bank Management Game

BANK OF CHINA
Present lectures and lead discussions on managing interest rate and foreign exchange rate risks using forwards, futures, swaps, options, and securitized assets.

BUSINESS ADDRESS AND TELEPHONE NUMBERS

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UE-88 REMAND / PGE EXHIBIT / 6700
HESS

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

The Risk Premium

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alan C. Hess, Ph.D

February 15, 2005

I. Introduction

Q. Please state your name and qualifications.

A. My name is Alan C. Hess. I am a professor of finance and business economics in the University of Washington Business School. My qualifications appear at the end of this testimony. I have written and consulted extensively in the areas of finance, commercial damages, copyright infringement, and commercial banking.

Q. What is the purpose of your testimony?

A. I provide an analysis of the effects on a regulated utility's cost of capital when it is not able to earn a return on plant and equipment that has been retired prior to the end of the asset's depreciation life. I show the equity risk premium that a rational investor would require to continue investing in a regulated utility whose assets are subject to default risk. Default risk in this case relates to the ability of PGE investors to earn a rate of return on the unamortized investment in Trojan. I discuss why adequate compensation of investor risk is necessary in meeting customers' demands and decommissioning risk and its applicability to utilities is modeled to show that required ROE increases with increased risk.

Q. Can you describe the capital attraction function of a regulated electric utility?

A. Yes. The production and distribution of electricity in a growing economy requires continual maintenance, upgrading, replacement, and enlargement of the plant and equipment that produces and distributes the electricity. An investor-owned public utility finances its ongoing physical plant improvements internally from its operating cash flows, and externally via borrowing and issuing equity.

Q. What is the role of investors in providing investment capital?

A. Investors, who buy the utility's bonds and stocks, are willing to provide funds to the utility only if they expect to receive a return on their financing that compensates them for the rate of return they would have received on an alternative use of their funds that has the same risk as an investment in the utility.

Q. What is the role of a Public Utility Commission (PUC) in capital attraction?

A. Public utility commissions attempt to set the rates that a regulated utility can charge its customers at levels that allows the utility to convince investors that they will be competitively compensated for buying the utility's debt and equity.

Q. What if the PUC does not set rates sufficient to assure investors that they will be competitively compensated?

A. Investors will not provide sufficient financing to the utility for it to have the wherewithal to meet its customers' electricity demands. The opportunity-cost based rate of return that investors expect to receive is the utility's cost of capital.

Q. What tools does a PUC have to determine a fair rate of return for equity investors?

A. There are several financial tools that a PUC could use, such as the Discounted Cash Flow (DCF) or Capital Asset Pricing Model (CAPM). I base my discussion on CAPM because its formulation allows for explicit recognition of factors important to this proceeding. The CAPM formula relates the cost of equity capital, k_e, to the risk free interest rate, r_f, the contribution of the utility's payoff to the risk of a well-diversified portfolio, β, and to the equity risk premium per unit of risk that investors require, λ. The CAPM formula is:

$$k_e = r_f + \beta \cdot \lambda . \qquad (1)$$

Q. Please summarize how the CAPM formula works?

A. Investors require compensation equal to the rate they would have earned on a risk free assets, such as a default-free U.S. Treasury security, plus a risk premium that is the product of the utility's risk as measured by its beta, β, times lambda, λ, the risk premium that investors require for each unit of risk they bear.

Q. Does the CAPM formula take into account enterprise default risk?

A. No. The CAPM serves as a framework to discuss the cost of equity capital for an ongoing business. It does not include a component for an abrupt end to the business. The CAPM estimate may be thought of as the expected rate of return to bearing business and financial risk but not default risk.

Q. Does the CAPM assumption of no default risk apply to a regulated utility?

A. This assumption of a going enterprise may not hold for a regulated utility whose revenues are based in part on their capital equipment being in use.

Q. Why is it that the traditional CAPM formula may not apply to a regulated utility?

A. If the utility takes some of its capital stock out of use, it may not be able to charge its customers a rate of return on the decommissioned plant and equipment. In the event of plant and equipment decommissioning, the CAPM-based rate of return that investors expected to receive on their investment in the securities that funded the plant is replaced with a rate of return of zero.

Q. If an equity investor knows he is at risk of not receiving a return on a portion of his investment, how could he be compensated?

A. Before they buy a utility's equities, rational investors should anticipate that the utility may decommission some of its plant and terminate the associated rate of return revenue. If so,

investors will require an extra risk premium before they buy the utility's securities to compensate them for the potential loss of their rate of return. This premium has been formally established for corporate bonds.[1] A similar analysis can be applied to equity.

Q. What investment choices does an equity investor have?

A. An investor has a choice between buying equity in a rate-regulated, investor-owned utility, or in another company or portfolio of companies that has the same risk. If the investor buys shares in another company or companies his expected payoff can be represented using the CAPM as $(1+r_f+\beta\lambda)$. If instead, the investor buys equity in a rate-regulated utility, his expected payoff depends on whether the utility keeps the plant and equipment in use.

Q. Please describe how asset impairment risk can be quantified from an investor perspective.

A. Let p be the probability that the utility will decommission some of its plant and equipment before it has generated sufficient revenues to compensate investors for the opportunity cost of their investment in the utility's securities. If this occurs, investors get back their investment but they do not continue to receive a rate of return on their investment. The expected payoff per dollar invested in the event of plant decommissioning is p.

Q. Please describe the risk premium equity investors require associated with this asset impairment risk.

A. Investors know before they invest that the utility may decommission some of its plant and equipment, which reduces the cash flow it has available to pay to investors. Rational investors require an additional risk premium to compensate them for the reduced cash flow

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[1] Darrell Duffie and Kenneth J. Singleton, "Modeling Term Structures of Defaultable Bonds," *The Review of Financial Studies* Special 1999 Vol. 12, No.4, pp. 687-720.

they suffer in the event of decommissioning. Let δ be the decommissioning risk premium. With probability *(1-p)*, the utility will continue to operate the plant and equipment. If the utility does not decommission any of its plant and equipment, the expected return to investors is $(1-p)(1+rf+\beta\lambda+\delta)$. The cost of capital for the ongoing plant and equipment must be increased by δ to compensate investors for the chance of decommissioning.

Q. What equity return does an investor require where this asset impairment risk exists?

A. The expected payoff to an investor for every dollar invested in the utility's equity is:

$$p \cdot 1 + (1-p) \cdot (1 + r_f + \beta \cdot \lambda + \delta). \qquad (2)$$

In this payoff to equity equation, the one stands for the amount of the investment. A rational investor requires that two investments of equal risk have equal expected rates of return. For the regulated public utility that cannot earn a return on its decommissioned plant and equipment, this equal-rate-of-return condition is

$$1 + r_f + \beta \cdot \lambda = p \cdot 1 + (1-p) \cdot (1 + r_f + \beta \cdot \lambda + \delta). \qquad (3)$$

The left-hand-side is the expected rate of return on an alternative investment with systematic, ongoing risk equal to the systematic, ongoing risk of the utility. The right-hand-side is the expected rate of return on a rate-regulated utility that loses some of its cash flow when it decommissions plant and equipment.

The equal-rate-rate-of-return condition can be rearranged to express the required size of the decommissioning risk premium as:

$$\delta = (1-p)^{-1}(1 + r_f + \beta \cdot \lambda - p) - (1 + r_f + \beta \cdot \lambda). \qquad (4)$$

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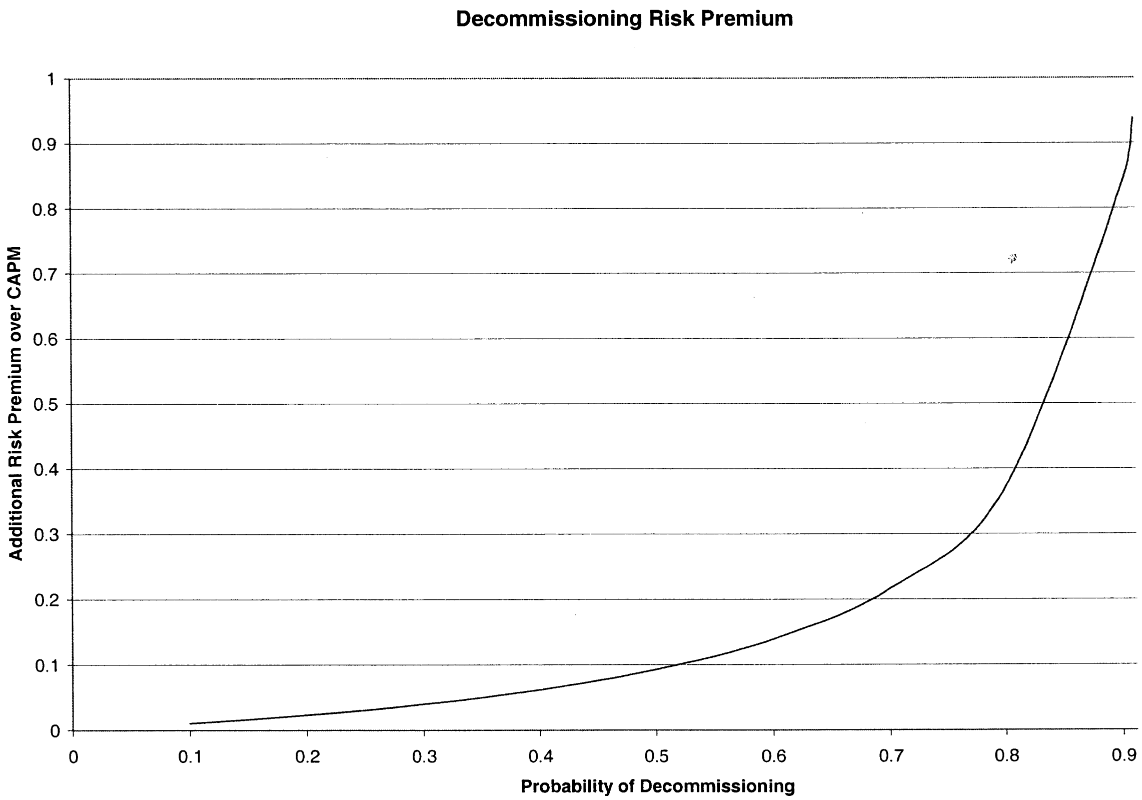

Q. Please give an example of how this risk premium formula can be applied to a utility.

A. The figure above plots the decommissioning risk premium against the probability that the utility will decommission some of its plant and equipment and give up the return on its decommissioned facilities.[2] This figure shows a plot of equation (4) for representative values of the risk-free rate, which is set at 4% in line with the rate on 10-year Treasury bonds in December 2004, a beta of 0.8, an equity premium of 6.6%, which is the difference between

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the average annual rate of return on the S&P 500 index and the 10 year Treasury rate for the years 1926-2003, and probabilities of decommissioning ranging from 0.1 to 0.91.

Q. Please describe the implications to a regulated utility and its equity investors of the foregoing graph.

A. Increases in the utility's probability of decommissioning increases the decommissioning risk premium that investors require to own the utility's stock. The only place the investor can look for this expected return is from the utility's cash flows if it keeps the plant and equipment in use. They must receive greater expected cash flows from the utility's ongoing operations to compensate them for the possibility of decreased cash flow in the event of plant and equipment decommissioning. Once the utility decommissions the plant and equipment, its cash flow decreases and it has less money available to pay to its shareholders. As a result, the cost of capital for ongoing plant and equipment is higher for a rate-regulated utility that forfeits the return on its investment in plant and equipment that is not in use.

Q. Please summarize your testimony.

A. The CAPM gives the expected rate of return on an investment in an ongoing business that does not have a truncated return distribution. A rate-regulated utility may not be permitted to earn a return on plant and equipment that is not in use. This truncates its return distribution. To be willing to buy shares in a rate-regulated utility, rational investors require an additional risk premium above the CAPM risk premium. This premium compensates them for the possible loss of future returns from investing in a utility that subsequently decommissions some of its plant and equipment. This decommissioning risk premium depends on the components of the CAPM and the probability that the utility will decommission some of its

plant and equipment. The decommissioning risk premium increases with the probability of decommissioning.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
6701	Witness Qualifications

ALAN C. HESS

Alan Hess is an Academic Affiliate of ERS Group and Professor of Finance and Business Economics in the University of Washington Business School. He holds M.S. and Ph.D. degrees in economics from Carnegie Mellon University and a B.S. in industrial management from Purdue University.

Professor Hess's academic and consulting interests encompass both economics and finance. He has conducted studies of:

- Banks, savings and loans, credit unions, insurance companies, factors and investment banks.
- Damages arising from trademark and patent infringement, antitrust, and commercial disputes.
- Event studies of the effects of public announcements on stock prices.
- The valuation of residential and commercial real estate including the effects of alternative financing techniques and environmental restrictions.
- The management of risks using derivative financial instruments including futures and securitized assets.
- The valuation of public utilities.
- The costs and benefits of highway construction projects.

Professor Hess has served in the Federal Reserve System and at the Securities and Exchange Commission. He has won numerous teaching awards including the University of Washington's Distinguished Teaching Award; the M.B.A. Association's Distinguished Professor Award, the Executive MBA Program's Excellence in Teaching Award, the Burlington Northern Distinguished Teaching Award, and the Wells Fargo Outstanding Teaching Award.

EDUCATION

1969	Ph.D. in Economics	Carnegie Mellon University, Pittsburgh, PA
1967	M.S. in Economics	Carnegie Mellon University, Pittsburgh, PA
1963	B.S. in Industrial Management (with distinction, economics honors)	Purdue University, West Lafayette, IN

EMPLOYMENT HISTORY

September 1996 to present	Co-Founder and Principal KeyPoint Consulting LLC, now ERS Group
1967 – present	Assistant, Associate and Professor of Finance and Business Economics , University of Washington
Autumn 1997	Visiting Professor of Finance University of California at Berkeley
Spring 1992	Visiting Scholar, Universidad Nova de Lisboa
Spring 1986	Visiting Professor of Finance Graduate School of Business, University of Chicago
Autumn 1983	Visiting Professor of Finance Graduate School of Business, University of Chicago
Autumn 1982	Visiting Scholar Federal Reserve Bank of Kansas City
Academic year 1977 - 1978	Visiting Associate Professor College of Business, University of Maryland
Academic years 1976 – 1978	Economic Fellow Securities and Exchange Commission, Washington, D.C.
Autumn 1976	Visiting Associate Professor of Economics Virginia Polytechnic Institute and State University
Autumn 1973	Visiting Associate Professor of Economics Department of Economics, University of Virginia
September 1965- August 1967	Economic Fellow Federal Reserve Bank of Cleveland
June 1963 - July 1964	General Electric Computer Department Financial Management

LITIGATION AND BUSINESS CONSULTING EXPERIENCE

ANTITRUST

UltraHue v. Xerox. Analyzed the degree of competition in the market for color laser printers. Assessed whether Xerox has market power in the sale of solid ink sticks. Deposition testimony pursuant to a case filed in United States District Court, Western District of Washington at Seattle.

BANKING AND FINANCIAL INTERMEDIARIES

Served as an expert witness for Recreational Equipment and US Bank in a lawsuit involving an auction sale of a credit card portfolio. Deposition testimony.

Helped defend Associates Financial Services Company against a charge that it violated Montana law in dealing with sub-prime borrowers.

Testified in Guam court about the differences among bank lending agreements, letters of credit, and loan guarantees.

Testified in federal court regarding the nature of and international markets for standby letters of credit.

Advised Bank of America, which was a senior lender on a non-performing loan, on its financial responsibilities to a subordinated lender to the same borrower.

Evaluated the financial performance of KeyBank of Idaho relative to its peers for the purpose of assessing the importance of reducing personnel and occupancy expenses. Deposition testimony.

Testified before the Washington state senate regarding the financial health of WSCUGA, a private credit union insurer, the economic bases for private insurance of credit unions, and the effects of proposed changes in the insurance system on credit union members and the insurer.

Assessed the accuracy of assertions by a dismissed examiner that the Federal Home Loan Bank of Seattle was neglect in its oversight of the risk management activities of a federally insured bank.
Assessed the accuracy of assertions by regulators that Benj. Franklin Savings was taking undue risks before it failed. Examined the effects on risks and returns of regulators requiring the bank to sell offsetting pieces of the derivative portfolio at

different times.

Analyzed the financial effects on First Interstate Bank of Washington of alternative strategies for disposing of a portfolio of mortgages acquired as part of a government assisted takeover of a failed savings bank.

Advised First Interstate Bank of Washington on the incremental cash flows and net present value of a proposed new computer system.

Advised the board of directors of Telco credit union on actions to overcome short-run problems, and recommended changes in performance evaluation and monitoring procedures to improve long-run performance.

Estimated damages to a factor from early termination of a factoring contract by a startup manufacturer. Testified in superior court.

Helped defend the Washington state Director of Banking against a charge that he conspired with a failing bank to deny continued credit to a developer who was in arrears on a loan.

Analyzed the effects of F.I.R.R.E.A on the financial performance of the 5th 3rd Bank.

Analyzed the effects of F.I.R.R.E.A. on the financial performance of Benj. Franklin Savings Bank.

Analyzed the effects of F.I.R.R.E.A. on the financial performance of D&N Bank.

Adviser to Seattle City Employees' Pension Fund. Help evaluate performance, choose asset allocations, and select managers.

COMMERCIAL DAMAGES

ATT v. GTE. Estimated damages to a supplier of business telephone services due to alleged false advertising by a competitor.

Advised a leveraged buyout firm on the price they should pay for a pulp and paper mill. Constructed pro forma financial statements, estimated the cost of capital, and estimated the discounted cash flow value of the company.

Qualcomm v. Ericsson. Estimated damages to a cellular telephone design and manufacturing company due to unfair business practices by a competitor. Included an event study of the effects of each company's product announcements on the other company's stock price.

Strobe Data v. Digital Equipment. Estimated damages to an integrated software and hardware design firm resulting from an alleged breach of contract by a supplier of a critical component. Deposition and testimony in federal court.

Estimated damages to a recycling processor due to a breach of contract by one of its waste suppliers.

Estimated the economic damages to Reinell, a boat manufacturer, of contaminated resin used in the production process. Testified in federal court.

RSR v. AIU Insurance. Helped defend AIU against a charge that its alleged nonpayment of environmental cleanup costs affected the cost of capital of an insured lead recycler.

Analyzed the effects of the stock market and an earthquake on the financial performance of a high-end retail furniture store.

PATENT AND COPYRIGHT INFRINGEMENT

CipherTrust v. IronPort. Evaluated damages to an inbound email appliance company due to alleged trademark infringement. Estimated plaintiff's lost profits, defendant's unjust enrichment, reasonable royalty, and corrective advertising damages. Deposition testimony.

Mackie v. Behringer. Estimated damages to an audio mixer manufacturer from alleged trademark and trade dress infringement. Deposition testimony.

CyberMedia v. Symantec. Estimated damages to a software company from its loss of market share caused by a competitor using many lines of identical code in a widely distributed utility.

Estimated damages to an inventor of medical devices due to alleged patent infringement by St. Jude Medical.

Chamberlin v. Overhead Door. Estimated damages to an electronic garage door opener company due to alleged patent infringement by a competitor.

PUBLIC UTILITY CONSULTING

U.S. West New Vector. Used statistical transfer functions to estimate consumers' demands for cellular service. Paid special attention to estimating price elasticities.

Williams' Gas Pipeline division. Estimated the cost of equity capital, the cash-based rate of return on new projects, the cash-based rate of return on existing projects, the cash-based regulatory rate of return, and economic value added for Williams.

U.S. West. Analyzed the financial consequences of defeasing bonds. Made presentation to board of directors supporting defeasance.

W.I.T.A. v. Pacific County P.U.D. # 2. Analyzed the possible economies to a public utility from being a retail Internet service provider. Deposition testimony.

Built and implemented a discounted cash flow model of public utilities with holdings in the State of Washington for the purpose of assessing their values for *ad valorem* taxes.

REAL ESTATE CONSULTING

Fluke Capital. Analyzed the effects on the city of Bellevue, Washington's tax revenues and convention business of a shortage of hotel rooms due to environmental regulations preventing construction of a city-approved hotel.

SECURITIES LITIGATION

Conducted an event study of the effects of Nortel's earnings announcements on its stock price.

Conducted an event study of the effects of Southeastern Bancorp's earnings announcements on its stock price.

Conducted a "fraud-on-the-market" study of alleged improper conduct by Asia Pulp & Paper.

VALUATION

Analyzed the financial performance of Saber pursuant to a charge that its rates were sufficiently high that it earned monopoly profits.

Reviewed three consultants' valuations of a privately held company. Assessed accuracy of discounted cash flows, capitalized earnings, and adjusted book values.

Reconciled different estimates.

Appraised 50.2% of the stock in a closely held investment company for estate tax purposes.

CONSULTING FOR GOVERNMENTS

Washington State Legislative Transportation Committee. Conducted a cost and benefit analysis of several major transportation projects in a heavily congested section of Seattle beset by traffic conflicts between trucks, trains, cars, bicycles, pedestrians, sports events, port shipping, and ferry traffic.

Bumbershoot. Built a financial model of Bumbershoot, a Seattle city-sponsored festival, from the perspective of making it a stand-alone, private enterprise. Estimated the amount of equity needed to finance the venture.

Estimated the costs to King County, Washington of extra police officer and clerical staff time required by an unfunded mandate from the Washington state legislature governing required police responses to domestic violence calls. Deposition testimony.

Projected changes to state-chartered credit unions' financial performances if the Washington State legislature subjects them to the Business and Occupation tax.

RESEARCH PAPERS

"Are the Major Japanese Banks Uniform or Unique?" With Kathryn Dewenter and Yasushi Hamao. Presented at the NBER/CEPR/CIRJE/EIJS Japan Project Meeting, Tokyo, September 2004.

"Are Relationship and Transactional Banks Different? Evidence from Loan Loss Provisions and Write-Offs." With Kathryn Dewenter. Presented at the Financial Intermediation Research Society conference, Capri, Italy, May 2004. Presented at the European Financial Management Association conference, Basle June 2004.

"Conditional Time-Varying Interest Rate Risk Premium: Evidence from the Treasury Bill Futures Market." With Avraham Kamara. Forthcoming, *Journal of Money, Credit and Banking.*

" Risks and Returns in Relationship and Transactional Banks: Evidence from Banks' Returns in Germany, Japan, the U.K., and the U.S.," (with K. Dewenter), Cambridge University Press, 1999.

"An International Comparison of Banks' Equity Returns," (with K. Dewenter),

Journal of Money, Credit, and Banking, August 1998.

"A Market-Based Risk Classification of Financial Institutions," (with K. Laisathit), *Journal of Financial Services Research,* December 1997. One of the ten most frequently downloaded papers on the Financial Economics Network.

"Portfolio Theory, Transaction Costs, and the Demand for Time Deposits," *Journal of Money, Credit, and Banking,* November 1995

"The Term Premium: Default, Liquidity and Interest Rate Risk," (with A. Kamara), abstract in *Journal of Finance,* Vol. 50, No. 3, July 1995, pp. 979-980

"Do Regulated Utilities Have Growth Opportunities?" *Assessment Journal,* July/August 1995

"Elements of Mortgage Securitization," (with C. Smith), Reprinted in *Studies in Financial Institutions: Commercial Banks,* C.M. James and C.W. Smith, eds., McGraw-Hill, 1994

" The Effects of Transaction Costs on Households' Financial Asset Demands," *Journal of Money, Credit, and Banking,* August 1991

"Elements of Mortgage Securitization," (with C. Smith), *Journal of Real Estate Finance and Economics,* 1988

"Could Thrifts Be Profitable? Theoretical and Empirical Evidence," *Carnegie-Rochester Conference Series on Public Policy,* Spring 1987

"The Intermediation Profit Margin: A New Measure of Savings and Loan Association Financial Performance," Center for the Study of Banking and Financial Markets *Digest,* Winter 1987

"Size Effects of Seasoned Stock Issues: Empirical Evidence," (with S. Bhagat), *Journal of Business,* October 1986

"Discount Mortgage Financing and Housing Prices," (with P.A. Malatesta), *Housing Finance Review,* Summer 1986

"Comment on Quantification of Selected Elements of Non-Standard Financing which Are Only Partially Capitalized," *Property Tax Journal,* December 1985

"Discount Mortgage Financing and House Prices," (with P.A. Malatesta), Center for the Study of Banking and Financial Markets *Digest,* Winter 1985

"Introduction to Duration," Washington Credit Union League *Investment Guide,* 1984

"Asset and Liability Management Strategies," Center for the Study of Banking and Financial Markets *Digest,* Summer 1984

"Variable Rate Mortgages: Confusion of Means and Ends," *Financial Analysts*

Journal, January/February 1984

"Lease Rates on Washington State Aquatic Lands: Some Economic Considerations," *Western Tax Review,* Fall 1983

Abstract of "Tests for Price Effects of New Issues of Seasoned Securities," (with P. Frost), *The CFA Digest,* Winter 1983

Contribution to *Monetarism and the Federal Reserve's Conduct of Monetary Policy,* Subcommittee on Monetary and Fiscal Policy, Joint Economic Committee, U.S. Congress, December 1982

Review of *Setting National Priorities: The 1982 Budget* and *The Economy: Is this a Change in Direction? Journal of Money, Credit and Ranking,* November 1982

Duration Analysis for Savings and Loan Associations," *Federal Home Loan Bank Board Journal,* October 1982

"Tests for Price Effects of New Issues of Seasoned Securities," (with P. Frost), *Journal of Finance,* March 1982

A Brief History of the School and Graduate School of Business Administration of the University of Washington: The Hanson Years 1964-1981, editor, 1981

"Simulation of Skin Diseases for Teaching Dermatological Diagnosis," (with J.M. Short, M.D.), *Journal of Medical Education,* April 1980

"The Riskless Rate of Interest and the Market Price of Risk: Correction," *Quarterly Journal of Economics,* November 1978

"A Comparison of Automobile Demand Equations," *Econometrica,* April 1977

"Household Response to a Money Rain: Real and Portfolio Balance Effects Reconsidered," *Journal of Monetary Economics,* January 1977

"The Riskless Rate or Interest and the Market Price of Risk," *Quarterly Journal of Economics,* August 1975

"Household Demand for Durable Goods: The Influence of Rates of Return and Wealth," *Review of Economics and Statistics,* February 1973

"Experimental Evidence on Price Formation in Competitive Markets," *Journal of Political Economy,* March/April 1972

"The Money Supply Process," *Journal of Finance,* September 1971

"An Explanation of Short-Run Fluctuations in the Ratio of Currency to Demand Deposits," *Journal of Money, Credit, and Banking,* August 1971

"A Quantity Theory Approach to the Current Inflation," *Washington Business Review,* Summer 1969

"A Note on Supplemental Appropriations in the Federal Budgetary Process," (with G.W. Bowman, O.A. Davis, and H.S. Gailliot), *Papers on Non-Market Decision Making,* January 1967

ACADEMIC TEACHING

Financial markets and institutions
International finance
Banking
Microeconomics
Monetary economics
Macroeconomics

PROFESSIONAL TEACHING

SEAFIRST CORPORATE FINANCE SEMINAR
Present lectures and lead discussion on causes and consequences of interest rate risk; topics include calling and defeasing bonds, swaps, securitization, and monetary and fiscal policies

BANK OF AMERICA, MARKET RISK MANAGEMENT SEMINAR
Present lectures and lead discussion on factors affecting the level and structure of interest rates, duration, and immunization

BOEING COMMERCIAL AIRPLANE CO., SALES FINANCIAL TRAINING SEMINAR
Analysis of the sources of changes in the level and structure of interest rates and their implications for airplane financing

CHASE MANHATTAN BANK, ADVANCED PRODUCT SEMINAR
Present lectures and lead discussion on factors affecting the level and structure of interest rates, duration, and immunization

PACIFIC COAST BANKING SCHOOL
Present lectures to U.S. bankers on the workings of U.S. financial markets, their relationship to economic activity, and their effects on banks' financial performances. Present lectures and lead discussions on managing interest rate and foreign exchange rate risks using forwards, futures, swaps, options, and securitized assets.

BANKING AND SOCIETY IN AMERICA
Teach regional bankers from Japan about the Federal Reserve System and U.S. financial markets

KOREAN BANKERS PROGRAM
Present lectures to Korean bankers covering the structure and working of U.S. financial markets and the Federal Reserve System

MANAGEMENT PROGRAM, SCHOOL OF BUSINESS, UNIVERSITY OF WASHINGTON
Present lectures on monetary and fiscal policy and quantitative analysis of business decisions

SCHOOL OF EXECUTIVE DEVELOPMENT, THE INSTITUTE OF FINANCIAL EDUCATION
Activities include teaching savings and loan association executives the principles of financial management of financial institutions plus administering their playing of the Stanford Bank Management Game

BANK OF CHINA
Present lectures and lead discussions on managing interest rate and foreign exchange rate risks using forwards, futures, swaps, options, and securitized assets.

BUSINESS ADDRESS AND TELEPHONE NUMBERS

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July 2004

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CERTIFICATE OF SERVICE

I certify that I have this day served the following documents:

- Exhibit No. 6000, Testimony of Pamela G. Lesh;
- Exhibit No. 6100, Testimony of Randy Dahlgren;
- Exhibit No. 6200, Testimony of Jay Tinker, Patrick G. Hager, and Stephen Schue;
- Exhibit No. 6300, Testimony of Stephen M. Quennoz and Leonard ("Pete") S. Peterson;
- Exhibit No. 6400, Testimony of Patrick G. Hager;
- Exhibit No. 6500, Testimony of Jeff D. Makholm;
- Exhibit No. 6600, Testimony of Colin C. Blaydon;
- Exhibit No. 6700, Testimony of Alan C. Hess; and
- Portland General Electric Company Opening Brief,

by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, and by electronic mail pursuant to OAR 860-013-0070, to the OPUC Docket No. UE 88 et al. service list as attached.

Dated this 15th day of February, 2005.

PORTLAND GENERAL ELECTRIC COMPANY

By ____________________________________

J. Jeffrey Dudley, OSB # 89042
Portland General Electric Company
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Portland, OR 97204
Telephone: 503-464-8860
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February 15, 2005

via MESSENGER and E-Filing

Administrative Hearings Division
Support Unit
Public Utility Commission of Oregon
550 Capitol St., NE, #215
PO Box 2148
Salem OR 97308-2148

Re: In the Matters of OPUC Dockets **UE-88**, **DR-10** and **UM-989**
Testimony and Opening Brief of Portland General Electric Company

Attn: Filing Center

Enclosed for filing in the above-captioned docket are the original and five copies of the following documents:

Exhibit No. 6000, Testimony of Pamela G. Lesh: "Context, Principles, Building Blocks & Recommendation,"

Exhibit No. 6100, Testimony of Randy Dahlgren, "Ratemaking, Trojan History,"

Exhibit No. 6200, Testimony of Jay Tinker, Stephen Schue, and Patrick G. Hager, "Quantitative Analysis,"

Exhibit No. 6300, Testimony of Stephen M. Quennoz and Leonard ("Pete") S. Peterson, and Randy Dahlgren, "Asset Classification,"

Exhibit No. 6400, Testimony of Patrick G. Hager, "Cost of Capital,"

Exhibit No. 6500, Testimony of Jeff D. Makholm, "The Regulatory Compact,"

Exhibit No. 6600, Testimony of Colin C. Blaydon, "Impact on Rate of Return,"

Exhibit No. 6700, Testimony of Alan C. Hess, "The Risk Premium ,"

Opening Brief, and

Certificate of Service with official Service List

These documents are also being filed electronically per the Commission's eFiling policy to the electronic address PUC.FilingCenter@state.or.us, with copies being served on all parties on the service list via U.S. Mail. A xerox copy of the Public Utility Commission tracking information will be forwarded with the hardcopy filing.

PGE has scheduled an informal technical workshop for 1:30 p.m. on Thursday, February 24, in the OPUC Main Hearing Room. At this workshop, PGE will explain its analyses of the different scenarios.

Sincerely,

/s/ Pamela G. Lesh

PGL:lbh

cc: UE 88 Service List

Enclosures

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