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I. Policy

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

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

Q. What is the purpose of your testimony?

A. I provide evidence in support of the appropriateness of PGE's request for the deferral of the excess costs associated with the Boardman outage in compliance with the statute, regulatory guidelines, and regulatory policy. I also discuss the recommended treatment of Boardman's forced outage rate, and rate implications of the requested deferral.

Q. What is PGE's request in this docket?

A. PGE is requesting Oregon Public Utility Commission (OPUC or Commission) authorization to defer approximately $45 million incurred between November 18, 2005 (the date on which we filed this Application) and February 5, 2006 (the date PGE deemed this outage concluded) to continue providing our customers with power after the Boardman coal-fired generating plant went into a prolonged forced outage in October 2005.

Q. Is the $45 million all of the costs PGE incurred to continue providing power to customers during this Boardman outage?

A. No. The outage began on October 23, 2005 and we did not file an application for this deferral until November 18, 2005. We incurred $14 million to replace Boardman's output during this time.

Q. Will granting this deferral change PGE's rates?

A. No. Any rate increase to collect these costs will occur only after Commission review and approval of a tariff for the amortization of amounts deferred. For informational purposes, we presently estimate that, if the Commission adopted a three-year amortization period, the effect of including this cost recovery in PGE's prices would be a 1% increase.

Q. What role does deferred accounting have in Oregon's regulatory framework?

A. This tool is now statutory, although the practice of deferring certain costs or revenues that affect cost of service for later ratemaking treatment dates back much farther than the statute's adoption in 1987. It is one of the most versatile in Oregon's regulatory framework and, consequently, its uses are many and varied. For PGE alone, uses over the last 20 years have ranged from deferring legal expenses and conservation program costs to revenues from property sales, cost under-runs in information technology expenditures, and tax rate reductions.

Q. What elements of the applicable statute are you discussing in this testimony?

A. For purposes of this application, I discuss the portion of ORS 757.259 that states that anyone proposing to defer costs or revenues show that they are identifiable utility expenses or revenues the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers.

Q. Are the costs PGE is requesting to defer identifiable?

A. Yes. These are the expenses PGE records in FERC accounts 555 and 501 for Purchased Power and Fuel Expenses respectively. For purposes of this request, PGE proposed to defer amounts actually spent to replace Boardman's generation based on purchases we identified at the time we made them, offset by avoided fuel costs.

Q. Are the actual replacement costs the only method of calculating this replacement cost that can result in "identifiable expenses or revenues?"

A. No. In the early 1990s, the Commission approved PGE's deferral of costs associated with replacing the output of the Trojan nuclear generating plant, which first experienced a prolonged forced outage and subsequently closed pursuant to a least-cost planning analysis. For all of these deferrals, the Commission authorized a calculation of replacement power cost based on comparing PGE's expected total net variable power costs over the period of the deferral to those PGE actually incurred.

Q. Will granting this cost deferral minimize the frequency of rate changes or the fluctuation of rate levels?

A. Yes. PGE's only other option under Oregon's regulatory framework would be a request for an interim rate increase based on the difference between the variable cost of operating Boardman and the cost of purchasing power on the market. Because this was a forced outage caused by a repairable problem, a temporary rate increase option would have caused – not minimized – the frequency of rate changes and the fluctuation of rate levels. Deferring these costs instead allows the Commission to design an amortization schedule that minimizes rate fluctuations for this temporary cost increase.

Q. Could PGE have supported an interim increase for this cost change?

A. Yes, it is my opinion that we could have done so. In calendar year 2005, PGE earned just $64 million of net income, down from $92 million in the prior year not adjusted for these replacement power costs. The $64 million of net income is equivalent to an estimated 6.3% return on equity (ROE), which is significantly under the return on equity last authorized by the Commission. We expect worse results for 2006. This is not an instance in which cost decreases or load increases or both, over the period involved, offset the identified revenue requirement increase. I note, in addition, that the amount of this particular revenue requirement increase is almost double the amount PGE is requesting (non-RVM) in the 2007 test year rate case we recently filed.

Q. Will granting this cost deferral appropriately match costs borne by and benefits received by customers?

A. Yes. As explained above, the power that PGE bought to replace Boardman's output was actually used to provide service to customers. Absent this deferral, customers will have used power at a cost significantly less than PGE incurred to provide it.

Q. Did PGE include the full benefit of the avoided outage (April 29-May 27) in the deferral cost calculation?

A. Yes. At the time we filed for the deferral we expected the plant to return to service prior to the planned maintenance. Current expectations call for Boardman to return to service in the first week of May. We are honoring our earlier commitment to provide an offset for the full planned maintenance outage even though the plant is not expected to run during a portion of the planned maintenance period.

Q. Has the Commission provided guidance on how it will exercise its discretion in applying these three criteria from ORS 757.259?

A. Yes. In Order No. 05-1070, Docket UM 1147, the Commission explained the following:

> "The Commission will look to whether the event was modeled in rates and, if so, whether extenuating circumstances were involved that were not foreseeable during the rate case, or whether the event fell within a foreseen range of risk when rates were last set. If the event was not modeled, we will consider whether it was foreseeable as happening in the normal course of events, or not likely to have been capable of forecast. The Commission will examine whether or not the 'risks are reasonably predictable and quantifiable.
>
> Initially, the proper approach in analyzing an event is to examine the nature of the event, its impact on the utility, the treatment in ratemaking, and other factors used to evaluate whether a deferred account is appropriate. The next step is to examine the magnitude of the underlying event in terms of the potential harm. The type of event –

> modeled in rates or not, foreseeable or not – will affect the amount of harm that must be shown by the utility. If the event was modeled or foreseen, without extenuating circumstances, the magnitude of harm must be substantial to warrant the Commission's exercise of discretion in opening a deferred account. If the event was neither modeled nor foreseen, or if extenuating circumstances were not foreseen, then the magnitude of harm that would justify deferral likely would be lower."

Q. Was this forced outage of Boardman modeled in rates or foreseeable as happening in the normal course of events?

A. No. We forecast thermal plant availability, and conversely forced outage rates, using a rolling average of the four years prior to the year we are making the forecast. For example, to forecast Boardman's availability for 2006, we use the weighted average of the availability rates from 2001, 2002, 2003, and 2004. 2005 data would not be available in time to use in forecasting. The four years' historical data does not, and could not; reflect the full range of possible operating parameters. This is particularly true for such a major outage as the one causing the deferral application. A forced outage of this length is very rare for Boardman, as discussed in PGE Exhibit 200, and rare for the industry overall, as discussed in PGE Exhibit 300. The portion of the outage prior to our deferral application is probably more representative of a "normal" event. As noted above, PGE is not seeking recovery of these costs through the deferral.

Q. Doesn't the thermal plant forced outage forecasting methodology, by using historical information, spread the costs or benefits of forced outage rate variations like this one over time without the need for a deferral?

A. Yes.

Q. Given that, why have you proposed a deferral?

A. We believe a deferral is a better choice for several reasons.

First, including an outage of this length in the rolling four-year average methodology will seriously depress the forecasted availability of Boardman through 2011. During this time, PGE would have an opportunity to recover through Boardman's "better-than-forecasted" performance what we lost through the "worse-than-forecasted" performance of this outage period, with the "value" of that recovery depending on the markets in each of those years. Customers would "pay" more or less than the actual replacement cost we incurred. While this may be appropriate and acceptable to all for a range of "normal" forced outages, we believe that removing it from this methodology so that annual forecasts are closer to "normal" operation is the better course for customers and for PGE. For customers, it will match the costs more closely in time to the use of the power; for PGE, it will provide recovery more closely in time to the expenditures to replace Boardman output.

Second, unless the Commission continues to adjust PGE's prices each year based on a new net variable power cost forecast (as presently happens under the RVM), handling this outage through the forecasting methodology could prolong the adverse effects on customers even longer.

Third, PGE has proposed in our general rate filing that the Commission approve a new Annual Variance Tariff for sharing NVPC variances between customers and PGE. Although we can accommodate for forced outages experienced during the period of no variance sharing once in a period of variance sharing, again, the size of this outage makes handling it separately a better choice.

Q. How would PGE forecast Boardman's availability using the traditional four-year rolling average methodology if the Commission authorizes this deferral?

A. If the Commission authorizes this deferral, PGE will forecast Boardman's availability as if it was 100% available during the deferral period. This is predicated upon the Commission authorizing the deferral using output of 383 MWa and 380 Mwa for 2005 and 2006, respectively, which is Boardman's output at 100%. This is not the output, however, used in the 2005 and 2006 RVMs, which, based on the assumption that forced outages occur evenly across the year, show an output of 358 MWa over the deferral period. If the Commission uses the 358 MWa instead, PGE would need to assume a 6.5% forced outage rate for the deferral period to achieve a neutral result.

Q. Will the days of the outage prior to the deferral affect the forecasted forced outage rate?

A. Yes.

Q. Returning to the Commission's guidance in Order No. 05-1070, is the risk of a forced outage of this length "reasonably predictable and quantifiable?"

A. No. As discussed above, forced outages of this magnitude are rare events. Moreover, with replacement being at market, rather than from other utility capacity that is already reflected in the cost of service prices, market volatility makes it difficult to quantify such events even if one could predict them. Just over the last four years, market prices have varied between $34.87 and $79.90 for a one-year forward block purchase. Daily variation can be much greater both within and between years.

Q. What is the magnitude of harm?

A. For the entire first outage period (October 23, 2005 to February 5, 2006), we incurred approximately $64 million of excess power costs, as provided in Exhibit 300. The value of a foregone planned maintenance outage in the spring of 2006 reduces the amount to approximately $59 million. Across the entire outage period, the impact of excess power costs is 355 basis points on PGE's ROE. This estimate of the magnitude is based on an assumption that PGE has experienced the after-tax effect of the additional costs. Historically, if a utility absorbed $20 million of excess power costs, it was understood that the after-tax financial consequence to the utility was $12 million (assuming a 40% tax rate). We assume that the Commission's discussion in Order No. 05-1070, and Orders No. 04-108 and 04-357 on which it is based, reflects this view of financial consequences in discussing materiality.

Q. Is it a certainty that PGE will experience only the after-tax effects of the additional costs incurred to provide customers power during Boardman's outage?

A. No. The Commission is presently developing rules to implement SB 408, legislation passed in 2005 that requires utilities to "true-up" the difference between taxes they pay to various governments and taxes deemed collected in rates. Under some applications of this statute, a lower tax payment resulting from the effect of these additional costs on PGE's net income would result in a refund to customers. Thus, customers would receive the tax effects of the additional costs but, without this deferral, would not bear the costs themselves.

Q. Can you provide an example of the effect of this SB 408 interpretation?

A. Yes. For example, assume a utility absorbs $20 million of excess power costs. This would lower its taxes paid by $8 million. The suggested interpretation of SB 408 would require that the utility refund $8 million to customers, even though customers did not pay the $20 million in increased cost. Further, the rules for applying SB 408 may require that a utility "gross up" such tax-related refunds. The gross up would increase $8 million to approximately $13 million. Adoption of permanent rules in AR 499 could alter the financial consequence of excess power costs absorbed by the utility, which should influence the standards under which the Commission views materiality in deferral proceedings.

Q. How can the Commission assure itself that cost decreases or higher revenue does not offset some or all of the additional costs incurred to replace Boardman's output?

A. The primary means to accomplish this is the earnings test that occurs during the amortization phase. For example, in Docket UE 93, the earnings test resulted in PGE recovering only a portion of the Trojan replacement costs it had incurred because other cost and revenue changes offset the higher power costs.

II. Qualifications

Q. Ms. Lesh, please describe your qualifications.

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

Q. Does this conclude your testimony?

A. Yes.

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I. Introduction

Q. Please state your names and positions with Portland General Electric.

A. My name is Stephen Quennoz. I am Vice President, Power Supply. My qualifications appear in Section III of this testimony.

My name is Loren Mayer. I am the General Manager of the Boardman Plant. My qualifications appear in Section III of this testimony.

Q. What is the purpose of your testimony?

A. We provide background information regarding the operation and maintenance of the Boardman facility. We discuss the low-pressure turbine 1 (LPT1) history, and rationale behind its initial installation. We also discuss the outage, events leading to it, and our repair strategy. In addition, we present the wholesale power replacement strategies PGE employed with the Boardman outage.

Q. Do you have any Exhibits with your testimony?

A. Yes, PGE Exhibit 201 is a diagram of the Boardman turbine. The various turbines, generator, and exciter are noted. PGE Exhibit 202 is a timeline of the Boardman outage.

II. Plant Operations

Q. Please describe the LPT1 turbine.

A. The LPT1 turbine was designed for the Boardman Coal Plant by Siemens Westinghouse Power Corporation (SWPC). SWPC manufactured the double flow low-pressure rotors in 1999-2000 and installed them in June 2000. The design technology takes into account several design parameters to individually tailor each rotor for the specific generating unit. Some of the design parameters include: existing space available inside the steam turbine inner cylinder, the size and type of bearings, the normal and maximum steam flow rate, the contractual MW output, and the rating of the generator. Each turbine is designed individually using computer programs that size and shape each blade row so the turbine fits and performs correctly.

Q. Why did PGE decide to replace the LPT1 turbine in 2000?

A. The design of the original turbine was developed in the 1960s. Advances in analytical techniques, metallurgy and manufacturing since these units were built allow substantial improvement in efficiency and output without increasing the steam energy input. SWPC was able to take advantage of new technology by replacing the low-pressure turbine rotors and inner cylinders without replacing the outer cylinders and foundations. The new rotor and associated stationary parts were installed in 2000, replacing equipment that had been in operation for more than 20 years.

Q. How did the turbine perform after installation?

A. The plant output increased about 35 MW (100% share) for the same energy input and met the output guarantee. This is an improvement of about 7% in efficiency/output. From 2000 to 2005, there were no problems with the low-pressure turbines.

Q. What were the costs associated with the turbine installation?

A. Installation of the turbine, and the associated LP1 and LP2 rotors, required support work including:

- Engineering study for the generator,
- Upgrade of the ISO phase bus, and
- Installation of a new safety valve.

PGE's share of the total cost for the project was approximately $10.2 million.

Q. Did PGE perform major maintenance on the new turbine?

A. No. The turbine was only halfway through its first ten-year interval established by SWPC for major maintenance. The failure occurred after 5 1/2 calendar years of operation, or just over 50% of the interval. The ten-year maintenance for the rotor includes a scheduled inspection at which time the rotor is dust-blasted clean and inspected using magnetic particle technique to identify any areas of concern.

PGE has not incurred any maintenance costs since the installation of the turbine and rotor. In 2002, SWPC performed some maintenance under warranty. This included replacing the old bearings with a new, tilting pad design offering more load carrying capability. They also installed lift pumps to reduce wear rates when the rotor is on turning gear. This work was all performed under warranty provisions of the 2000 contract.

Q. Please explain the series of events leading to the forced outage.

A. Plant engineering noticed that vibrations at one of the two bearings for LP1 showed a slight upward trend in July of 2005. Vibrations were well below limits, but we started monitoring the trend. The upward trend continued and we could not determine a cause. In October, the vibration levels became so severe that we had to take the unit off line. We contracted with our independent vibration consultant, Robert Kowalczyk (RK ltd.), and with SWPC to review our vibration data and perform their own analyses. Both visited the site and collected and analyzed their own data before we had to take the unit offline. Both concluded that the data indicated a turbine "rub" due to a bowed shaft. SWPC recommended a shutdown and partial disassembly to look for a rub. After partial disassembly, rubs in the steam seal area were discovered and corrected. Following reassembly and restart, there were two unsuccessful efforts to rebalance the turbine. PGE and RK ltd. concluded that the difficulties could not be explained by a rub or bowed shaft and a complete disassembly was required. The full disassembly revealed a crack in the rotor.

Q. How did PGE attempt to minimize costs associated with repairs of the crack in the rotor?

A. First, repairing this kind of crack requires special expertise and equipment that can be found only in a repair shop. PGE obtained competitive bids from the turbine's manufacturer, SWPC, and from Alstom, another turbine manufacturer who has made numerous repairs to SWPC turbines. Availability was the deciding factor. Alstom could make the repairs nearly a month faster than SWPC.

Second, PGE shipped the rotor by air to Alstom's facility on the east coast. Putting the Boardman Plant – one of the company's most reliable, low-cost generating resources – back in operation was a top priority; therefore, PGE opted to fly the rotor assembly back east rather than ship it via truck, which would have taken an additional 10-12 days.

Q. Please explain the reinstallation procedure.

A. The rotor arrived back at Boardman on January 25, 2006 and was reinstalled by SWPC's field personnel in accordance with their requirements.

Q. Did the rotor perform at expected standards?

A. The rotor was being placed into service when a second outage occurred on February 6, 2006 due to generator rotor failure. PGE had operated the turbine at 50 MW for 4 hours, preparing for overspeed protection equipment tests. The LP1 rotor vibration was at or below pre-2005 levels when the second outage occurred.

Q. Please discuss the ongoing root cause analyses.

A. There are four parties performing separate root cause analyses related to the LPT1 failure. Both the manufacturer (SWPC) and the repair firm (Alstom) are performing analyses. PGE has contracted for one from Mechanical and Materials Engineering, an independent engineering firm specializing in such analyses. PGE is also performing its own root cause analysis. Completion of the analyses requires information from actual operation when the plant returns to service.

Q. Had the Boardman Plant experienced such an extended forced outage in the past?

A. No, this is a unique occurrence. When the plant was first operational in 1980-1981, there were some problems with turbine blade failures leading to an extended forced outage. Since then, however, any forced outages have been relatively short compared to the October 23-February 5 outage.

III. Plant Output Replacement Strategy

Q. Did PGE's power operations group employ different replacement strategies during the Boardman outage period?

A. Yes. Initially, PGE believed that the outage would be short-term, a matter of hours or days. PGE's power operations group replaced the majority of the energy associated with Boardman in the pre-schedule (day-ahead) or real-time markets. As the market normally trades in blocks of 25 MW, PGE decided to replace 375 MW with wholesale power purchases.

When Boardman notified the power operations group that the outage would be multi-month, the power operations group analyzed the most economical way to replace the plant output. They compared the forward power prices to the cost of PGE generation. They found that forward wholesale power prices were below the generating cost of PGE's Beaver plant, which was PGE's only power plant that wasn't fully committed for generation during the December-January period. Buying wholesale power forward was therefore less costly than generating with Beaver on an expected basis.

PGE did have to decide whether to buy the required power on a forward basis or wait and rely upon pre-schedule or real-time markets. The winter months are typically our peak load months and wholesale prices tend to spike during these months. As a result, we typically do not carry a significant short position into the winter months; this avoids our reliance on the short-term markets, with corresponding price and supply risks. Based on these factors, PGE purchased replacement power on a forward basis. Each replacement power transaction was identified and "flagged" at the time of its execution.

Q. What about the planned maintenance period April 29 – May 27?

A. Since PGE had already covered our needs for the planned outage, we would have been long for the planned maintenance period given that we planned to keep Boardman running until 2007. PGE's power operations group attempted to maximize the value of this excess energy by selling the position in the forward market. PGE began selling ‘May Boardman output’ in January and finished selling the last block of on-peak power during the last week of March. The Christmas – New Year's holidays and general lack of monthly liquidity prevented any sales in late December and early January. May became truly liquid once it became the prompt month during the last week of March as April rolled off.

Q. Please provide a summary of the replacement energy purchased by the Power Operations department.

A. Table 1, below, shows the amount of energy purchased by month for the deferral period.

Table 1:
Replacement Energy Purchased
in MWhs

	Forward		Pre-schedule		Real-Time	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Nov 18 - Nov 30	-	-	48,484	40,200	15,021	6,361
December	156,000	124,200	-	1,200	-	-
January	150,000	129,000	-	-	-	-
Feb 1 - Feb 5	8,000	12,600	-	-	-	-

IV. Qualifications

Q. Mr. Quennoz, please describe your qualifications.

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

Q. Mr. Mayer, please describe your qualifications.

A. I hold a Bachelor of Science degree in mechanical engineering from Oregon State University. I enrolled in Naval Reserve Officer Training Corps and upon receiving my commission I was assigned to work at Naval Reactors Division of the US Army Environmental Center on nuclear submarine power plant design. I graduated from the Bettis Atomic Power Laboratory's nuclear reactor engineering school, run by Westinghouse. After working 5 years at Naval Reactors, I worked in coal plant design for 3 years at Stearns

Roger, an architect-engineering firm in Denver, Colorado, on design of the Hungtington Plant for UP&L, and Antelope Valley Station for Basin Electric Power Cooperative. I joined PGE in 1977 where I spent 17 years in engineering, including four years as manager of the Generation Engineering department. Projects for which I had management responsibility included replacement of Marmot and Faraday dams, KB Pipeline, Third AC Intertie upgrade, and shared responsibilities for initial stages of Coyote Springs design. I next spent 6 years in hydroelectric plant management and participated in the modernization and centralization of operations for the West Side hydro projects. I have been General Manager of the Boardman Plant since August of 2000. I have been registered as a mechanical engineer in Oregon, but my license is currently inactive.

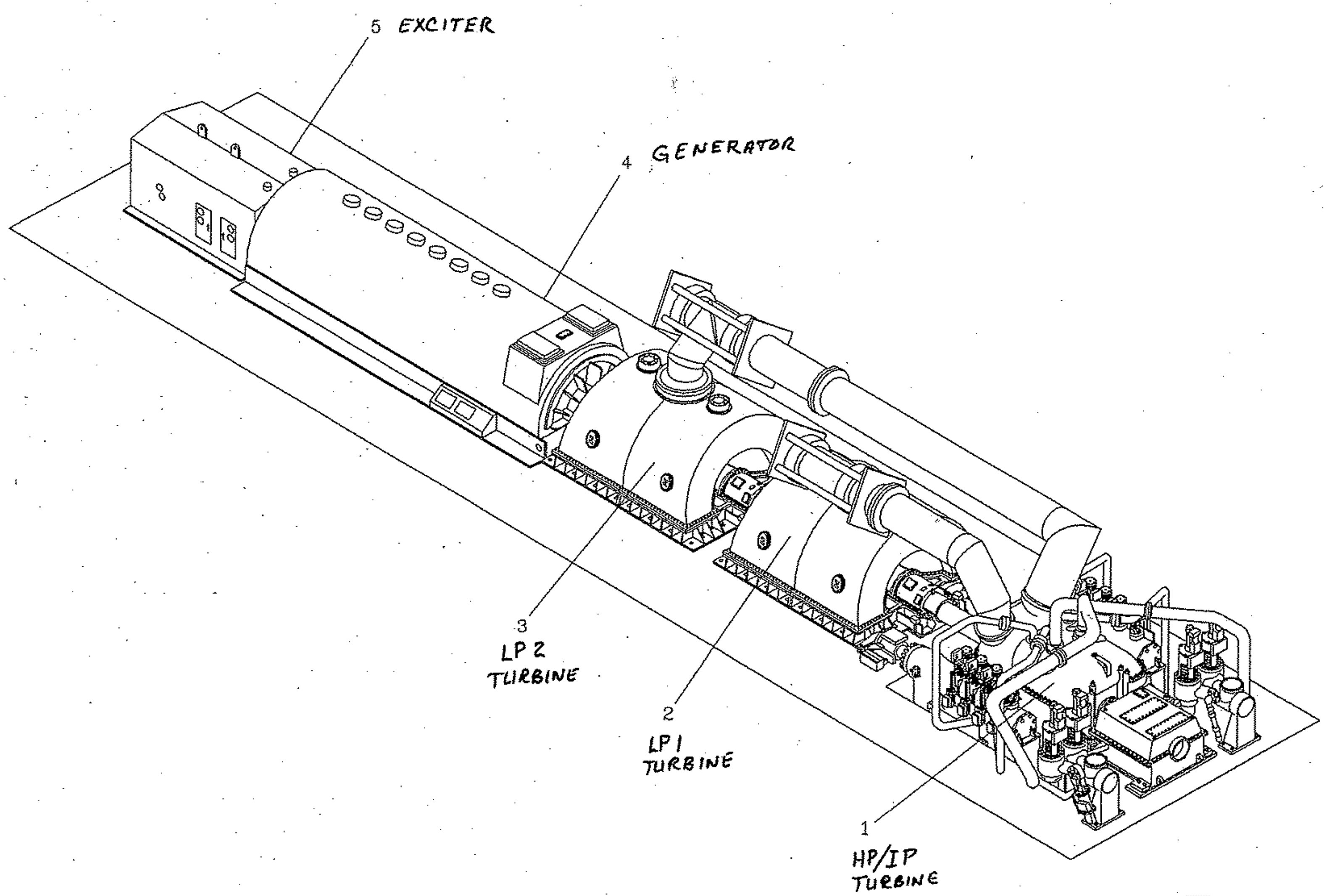
Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
201	Boardman Turbine Diagram
202	Boardman Outage Timeline

6. LIST OF AUXILIARY SYSTEMS

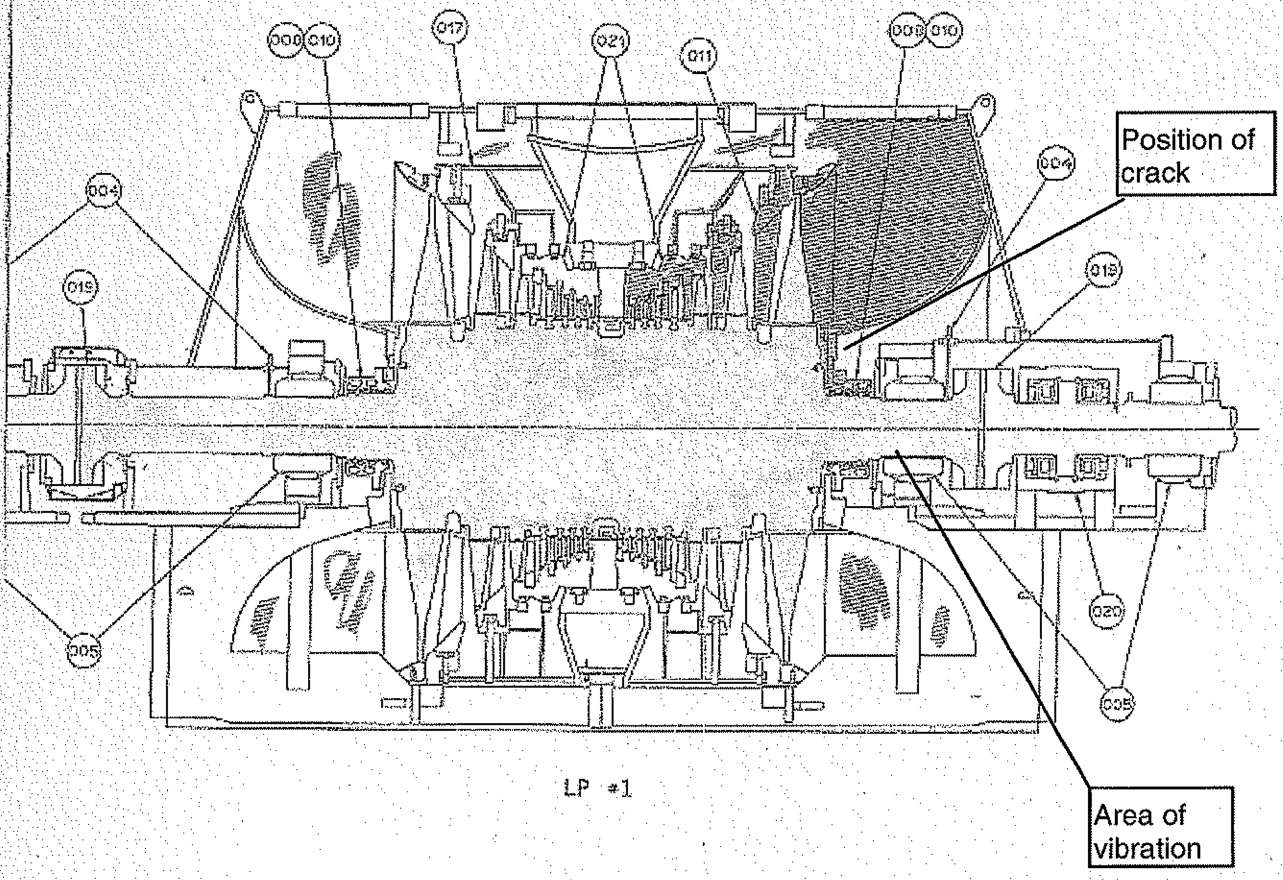


BASIC	5681206A
REV	
REIS	PUB. NO.
DATE	

Figure 1. BOARDMAN 1

4

PART NO.	DESCRIPTION
004	VIBRATION PICKUP
005	BEARING
008	GLAND OUTER
010	SEAL
011	BLADING
017	CYL COVER INNER
019	COUPLING
020	THRUST BEARING
021	BLADE RING LP



Longitudinal Section Assembly
Dwg. 2274J61-1

Boardman Outage Timeline

Event	Date
Vibration first noticed	July, 2005
Boardman taken offline	October 22, 2005
Attempted restart	November 16, 2005
Crack discovered	November 18, 2005
Deferral application filed	November 18, 2005
Transport for repairs	December 1, 2005
Received by Alstom	December 3, 2005
Repairs completed	January 24, 2006
Return trip began	January 24, 2006
Rotor arrival at Boardman	January 25, 2006
Reinstallation complete	February 4, 2006
Testing began	February 4, 2006
Outage ends	February 5, 2006

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I. Introduction

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

A. My name is Ted Drennan. I am a business analyst in the Regulatory Affairs department.

My name is Jay Tinker. I am a project manager in the Regulatory Affairs department.

My name is Patrick G. Hager. I am manager of Regulatory Affairs at PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. We present and explain PGE's proposed methodology for calculating the costs associated with the Boardman outage during the deferral period. As demonstrated below, these costs total approximately of $45 million. We also provide estimates of the impact of the Boardman outage on PGE’s Return on Equity (ROE). Finally, we provide analysis on thermal plant forced outages.

II. Method of Calculating Excess Power Costs

Q. What is the proper method for calculating the costs of the requested deferral?

A. There are two main components to consider, costs associated with energy purchases needed to compensate for the lack of Boardman's generation and costs avoided due to the outage. Energy purchases were valued either at the contract price, or market value, as described below. Costs avoided due to the outage included the incremental costs of production as established in the appropriate RVM forecasts. These incremental costs are $11.48 and $12.44 per MWh for 2005 and 2006. Line losses of 1.9% were used for both avoided costs and purchases. The following formula is a simplified version of the calculation for a single hour of the deferral period.

Cost = Energy * [(1 + Losses) * (Purchase Price) - (1 + Losses) * (Avoided Cost)]

Q. What is the correct time frame to analyze in determining the excess costs associated with the Boardman outage?

A. The correct time frame for the deferral is November 18, 2005 through February 5, 2006. The first date is when PGE filed a Notice of Application for Deferred Accounting of Excess Power Costs due to Plant Outage. This date is the starting point for the deferral period. The second date marked the completion of repair and re-installation of the turbine, the final day of the deferral period.

As explained in PGE Exhibit 200, during the forced outage PGE was able to complete the maintenance associated with a planned Boardman outage (April 29, 2006 – May 27, 2006). PGE had already purchased wholesale power to replace the lost Boardman energy during planned maintenance. With Boardman now expected to be in operation during this period, PGE was able to sell the now excess purchased power. The revenue from this sale partially offset a portion of the replacement costs during the deferral period.

Q. Please explain in more detail the method used to determine the value of the energy that replaced Boardman output during the outage.

A. Anticipated Boardman output for the deferral period was approximately 383 MWa for 2005 and 380 MWa for 2006. To fill this position, we initially purchased specific contracts that PGE's Power Operations Department "flagged" as replacement for the Boardman outage. When filling the Boardman position, the Power Operations Department generally bought in blocks of 25 MW, up to 375 MW. The specifics of the replacement strategy are discussed more fully in PGE Exhibit 200. For purposes of our analysis, we filled in any differences between the flagged purchases and total Boardman output with purchases at market.

Q. What were the costs of these purchases?

A. We used contract prices for flagged trades. We used the Dow-Jones Mid-Columbia daily index (DJ Mid-C) for both on- and off-peak to establish the market value for incremental purchases. We used forward market prices for incremental energy during the planned outage in April-May.

Q. Please explain the "avoided costs" used in the equation.

A. During the outage, PGE avoided certain costs associated with generation at Boardman. These incremental costs are mainly unused coal and associated transportation. We netted these avoided costs from the costs of purchases, as shown in Table 1 below.

Q. What are the results of the cost calculation?

A. As shown in Table 1, the net result is approximately $45 million of increased costs due to the Boardman outage.

Table 1

Excess Costs	**Dates**	**Dollars**
Pre-deferral	Oct 23 – Nov 17	$ 14,060,579
Deferral	Nov 18 - Nov 30	$ 7,115,190
	December	$ 19,768,532
	January	$ 20,743,313
	Feb 1 - Feb 5	$ 2,520,441
Savings (Maintenance Avoided)		
	Apr 29 - May 27	$ 4,763,722
Net Deferral Period Costs		**$ 45,383,755**
Total Net Excess Costs		**$ 59,444,334**

Q. What impact do the excess power costs have on PGE's financials?

A. The excess power costs incurred reduce ROE by 355 basis points, net of the associated reduction in income taxes. If, as a result of SB 408, PGE must refund the 2006 income tax effect, then the reduction in ROE would be even larger.

Q. Did you perform any analysis to determine if outages of this length are rare?

A. Yes. Data provided by the North American Electric Reliability Council (NERC) demonstrates that the 105 day length of the initial Boardman outage (October 23 - February 5) is extremely rare.

Q. What data did you analyze?

A. We used data from the NERC Generating Availability Data System (GADs). The data covered a total of 329 generating units operated by 103 reporting utilities over the past 20 years. The generating units were limited to those similar in size to Boardman, i.e. capacities between 250 MW and 500 MW. We further restricted the analysis to units that experienced a failure lasting at least one day. There were a total of 21,415 such outages.

Q. What were the results of this analysis?

A. The analysis demonstrates that forced outages of this length are infrequent. Of outages exceeding 24 hours, only 51 lasted 105 days or longer. This represents 0.238% of the outages in the study.

Q. Did you provide any exhibits with your testimony?

A. Yes, PGE Exhibit 301 contains the estimated ROE impact of the Boardman outage. PGE Exhibit 302 is the analysis of extended outages. PGE Exhibit 303 contains an estimate of PGE's 2005 ROE.

III. Qualifications

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

A. I received a Bachelor of Science in Economics from the University of Wyoming in August 1995. I also completed the coursework for a Master of Science in Regulatory Economics. From 1999 to 2001, I worked for the Iowa Department of Justice – Office of Consumer Advocate, as a Utility Analyst. While there I prepared and presented testimony to the Iowa Utilities Board in several utility related dockets. Between 2001 to 2002 I worked for two energy consulting firms: Energy Resource Consulting, based in Denver, as a Supervising Economist, and EES Consulting, based in Seattle, as a Senior Analyst. In 2002, I joined PGE in the Rates and Regulatory Department. My current position is a business analyst in the Regulatory Affairs department.

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

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

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

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return

Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is manager of Regulatory Affairs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
301	Estimated ROE Impact of Boardman Excess Costs
302	Extended Outage Frequency
303	Estimated 2005 ROE

Estimated ROE Impact of Boardman Excess Costs

Rate Base (1)		1,735,538	in $000s
Equity Share of Cap (1)		58.64%	
Net to Gross at 39.3% Composite Tax Rate		1.647	
Pre-Tax Cost for 100 Basis Points of ROE	$	16,766	in $000s

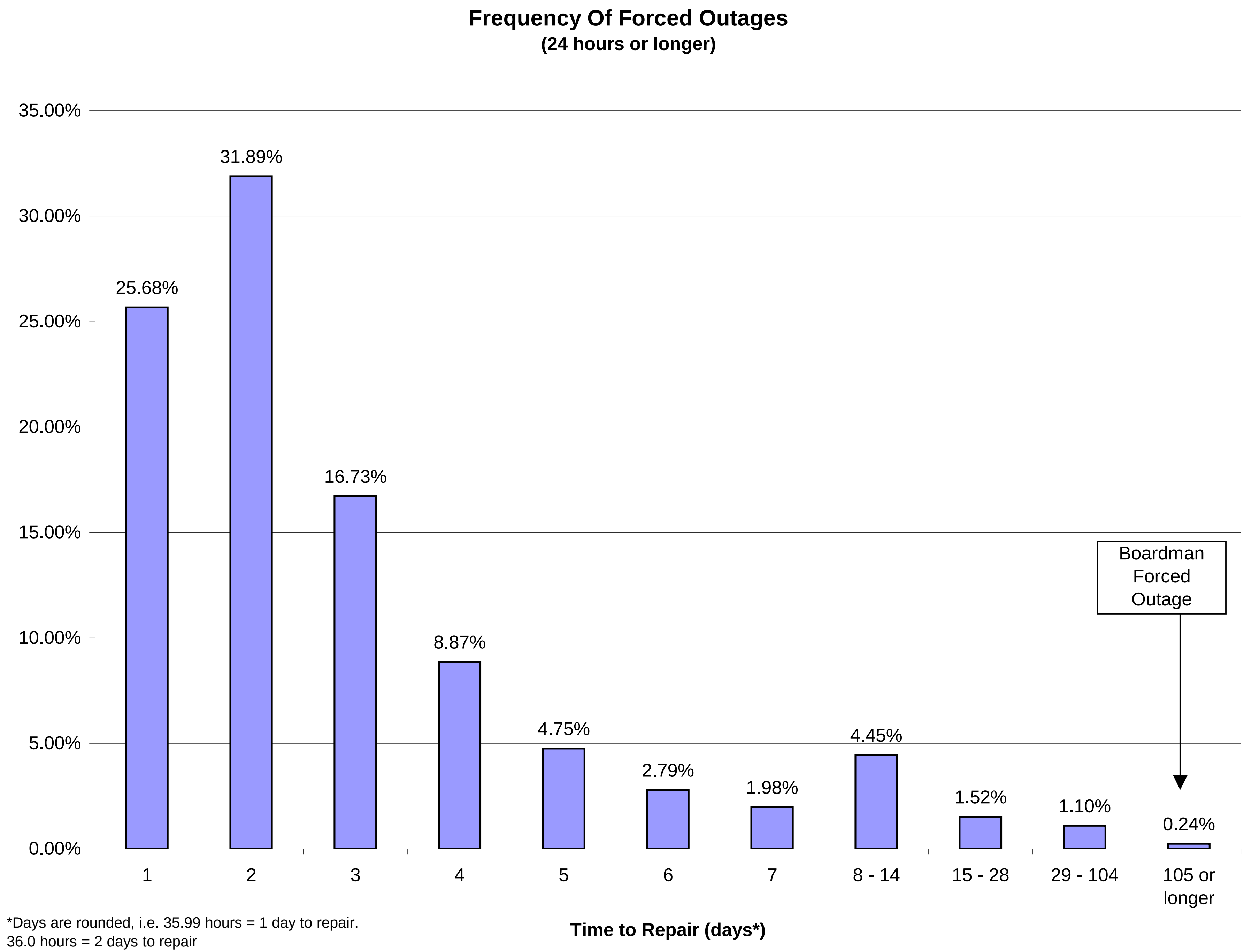
Boardman Excess Power Costs

Excess Costs	Start Date	End Date		Dollars
Oct 23-Nov 17	10/23/2005	11/17/2005	$	14,060,579
Nov 17 - Nov 30	11/18/2005	11/30/2005	$	7,115,190
December	12/1/2005	12/31/2005	$	19,768,532
January	1/1/2006	1/31/2006	$	20,743,313
Feb 1 - Feb 5	2/1/2006	2/5/2006	$	2,520,441
Total Excess Power Costs			$	64,208,055

Avoided Maintenance Savings

Apr 29 - May 27	4/29/2006	5/27/2006	$	4,763,722	ROE Impact (Basis Points):
Net Excess Power Costs			$	59,444,334	355

(1) PGE Results of Operations - 2004


Frequency Of Forced Outages
(24 hours or longer)
35.00%
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
25.68%
31.89%
16.73%
8.87%
4.75%
2.79%
1.98%
4.45%
1.52%
1.10%
0.24%
Boardman Forced Outage
1
2
3
4
5
6
7
8 - 14
15 - 28
29 - 104
105 or longer
Time to Repair (days*)
*Days are rounded, i.e. 35.99 hours = 1 day to repair.
36.0 hours = 2 days to repair

Extended Outage Frequency

Total Number of Incidents	21,415
Incidents longer than 105 days	51
Percent	0.238%

Days* to Repair	**Percent**
1	25.68%
2	31.89%
3	16.73%
4	8.87%
5	4.75%
6	2.79%
7	1.98%
8 - 14	4.45%
15 - 28	1.52%
29 - 104	1.10%
105 or longer	0.24%

*Days are rounded, i.e. 35.99 hours = 1 day to repair. 36.0 hours = 2 days to repair

Boardman Deferral Outage	
Initial Outage	10/23/2005
End of Deferral	2/5/2006
Total Number of Days	105

Estimated ROE for 2005

		($000s)
Rate Base (1)	$	1,735,538
Equity Share of Cap (1)		58.64%
Equity Rate Base	$	1,017,670
Net Income (2)	$	64,000
PGE's Estimated ROE		**6.29%**

(1) PGE Results of Operations - 2004
(2) PGE SEC Form 10-K - 2005

Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8926 • facsimile (503) 464-2200

Douglas C. Tingey
Assistant General Counsel

April 14, 2006

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of the Application of Portland General Electric Company for an Accounting Order Authorizing Deferral Of Excess Power Costs
OPUC Docket No. UM 1234

Attention Filing Center:

Enclosed for filing in the above-captioned docket are the original and five copies of the following Testimony of Portland General Electric:

Direct Testimony of Pamela Lesh (Exhibit PGE/100);
Direct Testimony and Exhibits of Stephen Quennoz and Loren Mayer (Exhibits PGE/200 through PGE/202); and
Direct Testimony and Exhibits of Ted Drennan, Jay Tinker and Patrick G. Hager (Exhibits PGE/300 through PGE/303).

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

/s/ DOUGLAS C. TINGEY

DCT:am

Enclosures

cc: UM 1234 Service List

CERTIFICATE OF SERVICE

I certify that I have caused to be served the foregoing **DIRECT TESTIMONY OF PORTLAND GENERAL ELECTRIC** in OPUC Docket No UM 1234, by U.S. Mail and electronic mail, to the following parties from the official service list:

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8351 ROSWELL RD
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consultrfi@aol.com

Dated this 14th day of April, 2006.

/s/ DOUGLAS C. TINGEY
Douglas C. Tingey