Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

October 9, 2007

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97301-2551

Re: UE ___ - Boardman Deferral Amortization

Attention Filing Center:

Enclosed for filing in the captioned docket is:

Original and five copies of:

- **Testimony and Exhibits of Stephen Quennoz (Boardman Operations/Replacement Power Costs - PGE/100-106) (non confidential portions)** [Exhibits 103C, 105C-A, B, C are confidential and not submitted at this time]**; and**
- **Testimony and Exhibits of Alex Tooman – Patrick Hager (Boardman Earnings Review - PGE/200-206)**

Three Copies on CD (only) of:

- **Work papers**

Original and one copy of:

- **Portland General Electric Company's Motion for Approval of Protective Order.**

PGE will submit the confidential portions of the testimony after the entry of a Protective Order.

This docket is the amortization phase of the Boardman deferral granted by the Commission in docket UM 1234. As explained in the submitted testimony, PGE proposes to offset the Boardman deferral with several credits due to customers so that there will be no rate impact from this amortization.

The following are the name and addresses of the persons authorized to receive notices and communications with respect to this proceeding:

Patrick G. Hager, Manager Rates and Regulatory Affairs Portland General Electric Company, 1WTC0702, 121 SW Salmon Street Portland, OR 97204 (503) 464-7623 (telephone) (503) 464-7651 (fax) pge.opuc.filings@pgn.com	Douglas C. Tingey, Assistant General Counsel Portland General Electric Company, 1WTC1301 121 SW Salmon Street Portland, OR 97204 (503) 464-7926 (telephone) (503) 464-2200 (fax) doug.tingey@pgn.com

This document is being filed by electronic mail with the Filing Center. An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return to me in the envelope provided.

These documents are being served upon the UM 1234 service list.

Thank you in advance for your assistance.

Sincerely,

R J Dahlgren

Randy Dahlgren
Director, Regulatory Policy and Affairs

RD:jbf
Enclosures
cc: Service List-UM 1234

UE ___ / PGE / 100
QUENNOZ

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Boardman Operations / Replacement Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Quennoz

October 9, 2007

Table of Contents

I. Introduction

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

A. My name is Stephen Quennoz. My position is Vice President, Power Supply. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is two-fold. First, I briefly summarize and describe the events between July 2005 and February 5, 2006, the end date of the first outage at the Boardman generating plant. Second, I describe the actions PGE took before and during the Boardman outage.

Q. Do you have any exhibits with your testimony?

A. Yes, I have six exhibits. PGE Exhibit 101 presents my testimony from UM 1234 which includes a detailed description of the Boardman outage. PGE Exhibit 102 presents a timeline of the events. PGE Confidential Exhibit 103C presents a sketch of the crack in the rotor shaft. PGE Exhibits 104-A through 104-H contain a series of pictures depicting the repair. PGE Confidential Exhibits 105C-A through 105C-C provide the root case analysis reports and PGE Exhibit 106 summarizes the replacement power cost purchases. PGE Exhibits 103C and 105C-A through 105C-C are confidential and subject to OPUC Order 07-153.

Q. How is your testimony organized?

A. I first outline the Boardman outage and our subsequent actions. I next present the results of the root cause analyses and their findings of fact. Third, I discuss the replacement power strategy employed by PGE during the period from October 23, 2005, through February 5, 2006, and demonstrate that PGE employed prudent wholesale power replacement strategies during the Boardman outage. Fourth, I address the prudency of our actions in operating the Boardman plant, demonstrating that the outage could not have been foreseen.

II. The Outage

Q. Please describe the events that led to the Boardman forced outage in the Fall of 2005.

A. Plant personnel monitor the bearing vibration levels on the turbines at Boardman. In July 2005, the vibration levels on the Low Pressure turbine 1 (LP1) showed a slight upward trend. Though well below operating limits at this point, we decided to monitor the vibration levels more closely. Through the summer and early fall, we continued to monitor the vibration levels and in October began corrective actions. However, on November 18, after several attempts to reduce the vibration levels of the LP1, the vibration levels reached a level that indicated the unit should be taken off-line and examined. A timeline of PGE actions regarding Boardman is provided in Table 1 below.

Table 1
Boardman Outage Timeline

Event	Date
Vibration levels first noticed	July, 2005
Boardman taken off-line	October 22, 2005
Attempted restart	November 16, 2005
Rotor 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

Q. What attempts did PGE make to address the problem?

A. First, before we took the plant off-line, our independent vibration consultant, Robert Kowalczyk (RK ltd.), and Siemens (original manufacturer of the turbine) visited the site, reviewed our vibration data, collected additional data, and performed their own analyses.

They both agreed that the data indicated a turbine "rub"[1] due to a bowed shaft. Siemens recommended a shutdown and partial disassembly to look for a rub, which we did. After partial disassembly, indications of rubbing in the steam seal area were discovered and corrected. Following reassembly, we attempted to restart the turbine. The vibration levels were more severe than before. We then tried twice to rebalance the turbine. PGE, Siemens, and RK ltd. concluded that the balancing difficulties could not be explained by a rub or a bowed shaft and a complete disassembly was required. We disassembled the turbine and discovered that the rotor was cracked. PGE Confidential Exhibit 103C shows the area where the crack occurred.

Q. Was the crack the root cause of the vibration?

A. Yes.

Q. What caused the crack?

A. What caused the crack remains unknown. Several root cause analyses, discussed in Section III, were unable to identify a specific cause.

Q. What actions did PGE undertake to return the plant to service after November 18, 2005?

A After we found that the rotor had cracked, we obtained competitive repair bids from Siemens and from Alstom, another turbine manufacturer who has made numerous repairs to Siemens' turbines. Although both manufacturers were highly qualified, we decided in favor of Alstom because Alstom could finish the repairs nearly a month earlier than Siemens could have.

Q. How did PGE ship the turbine to Virginia (site of Alstom repair shop)?

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[1] A 'rub' is a rotating part in contact with a stationary part *i.e.*, rubbing against each other.

A. The Boardman Plant is one of the company's low variable cost generating resources. Thus, putting the plant back in operation as soon as possible was a top priority. PGE arranged to have the rotor assembly flown to Alstom rather than ship it by truck, which saved 10-12 days transit time. Although flying the turbine was more expensive than trucking, the expected benefit from Boardman generating for 10-12 days over purchasing power for those days outweighed the additional transportation costs.

Q. Was Alstom able to repair the rotor?

A. Yes. Alstom repaired the rotor and returned it to Boardman on January 25, 2006. Siemens' field personnel re-installed the rotor in accordance with their requirements. PGE Exhibits 104-A through 104-H contain a series of photographs depicting steps in the repair process.

Q. Were the costs of transportation or repair included in the deferred amount approved by the Commission?

A. No.

Q. Did the plant return to full service?

A. No. When the plant was returning to service, a second outage occurred on February 6, 2006. PGE had operated the turbine at less than 100 MW for four hours, preparing for over speed protection equipment tests. The LP1 rotor vibration was at or below pre-2005 levels when this second outage occurred. The second outage is not a part of this proceeding.

III. Root Cause Analyses

Q. Has the LP1 turbine failure been analyzed?

A. Yes. Three parties performed separate root-cause analyses related to the LP1 failure. Both Siemens and the repair firm (Alstom) performed analyses. Siemens as the manufacturer and installer focused their analysis on the turbine, its placement, and operations since the installation in 2000. Alstom, as the repair contractor, performed a metallurgical analysis and reviewed and analyzed plant operational data. PGE also performed its own root cause analysis. In addition, PGE contracted with Mechanical and Materials Engineering (M&M Engineering), an independent engineering firm to provide an independent overview of the repairs. The findings are contained in PGE Exhibit 105-D.

Q. Did any of the analyses show that operator error was the source of the LP1 failure?

A. No. Each of the root cause analyses found that the manner in which PGE operated the turbine did not cause the rotor to crack.

As I discussed earlier in my testimony, after attempting repairs, the turbine generator was removed from service on November 18, 2005, for non-destructive examination of the rotor. While vibration levels were the cause of the removal from service, the analysis indicated that the *cause* of the *vibration*s was the cracking of the rotor shaft. The next step in the analysis is to determine 'what caused the rotor shaft to crack'.

Q. How did the analyses attempt to determine why the rotor shaft cracked?

A. Alstom reviewed the operating data from the date of the turbine installation, and performed a metallurgical analysis at their Materials Technology Center in Tennessee. The operating data included:

- vibration data,

- unit temperatures and pressures,
- bearing loads and alignment.

Alstom calculated mechanical stresses and evaluated the mechanical properties of samples taken from the cracked area.

Siemens analyzed the same type of data as Alstom. Their analysis focused on four potential causes:

- high cycle fatigue;
- low cycle fatigue;
- torsional overload; and
- environmental/manufacturing.

Q. Did either Siemens or the Alstom analysis pinpoint a root cause?

A. No. Neither analysis identified a single cause. Alstom concluded that:

> [T]here has been no supporting evidence that the plant has been mis-operated resulting in the failure of the LP1 turbine rotor. These results of the analysis, point in the direction of a misalignment of the train and an unsecured bearing pedestal. All the data and associated information indicate the root cause for this failure lies in a combination of factors.

Q. What did the root-cause analysis from Siemens reveal?

A. Siemens's findings are similar to those of Alstom. The manner in which the plant was operated did not play a role in the findings. Siemens considers that high cycle fatigue "due to misalignment induced by an unknown operational condition is the most probable root cause."

Q. Did any of the analyses find that PGE was at fault?

A. No. In fact, none of the analyses could determine a single root cause that led to the LP1 failure. And, none of them found any operational error that could cause the cracking.

Q. The root cause analysis by Siemens cited "misalignment." What does this mean?

A. The Boardman turbine generator train consists of:

- one combination high and intermediate pressure turbine (HPIP),
- two low pressure turbines, and
- one generator.

The components are bolted together, end-to-end, to form a single rotor exceeding 100 feet in length. The rotor is supported by bearings located near the ends of each of the individual components. The total weight of the turbine generator train is over 190 tons. All of the rotor components, and the bearings that support them, must be aligned to assure proper operation.

Perfect alignment of such large and heavy components cannot be achieved nor is it practical. The original design criteria for the rotor includes a specified margin (tolerance or range) to allow for slight movement of the rotor components or the bearings. Each part appears to have been operating within its specified tolerances that were consistent with standard industry practice. It may have been that a combination of small misalignments in this case contributed to the cracking of the rotor. However, no one specific part or cause could be identified.

Q. Did PGE perform major maintenance on the LP1 turbine that could have led to the misalignment?

A. No. PGE contracted with Siemens for major maintenance, including alignment of the turbine bearings and components. The maintenance work performed by Siemens was performed under warranty.

In 2002, Siemens performed some maintenance under warranty. This included replacing the old bearings with a new, tilting pad design offering more load carrying capability.

Q. Where did the crack occur?

A. PGE's root-cause analysis (PGE Confidential Exhibit 105C-A) indicated that the failure was initiated in the vicinity of bearing number 3. PGE Confidential Exhibit 103C contains a drawing highlighting the failure area.

Q. Did bearing number 3 previously show problems?

A. Yes. Temperature differences between bearing 3 and other bearings were noticed in 2000, and corrective actions were taken. Siemens modified the effective lengths of bearings 4, 5, and 6 in 2000. In 2002, Siemens installed the tilt pad bearings as mentioned above. The problem appeared corrected because the temperature differences were reduced.

Q. Was the misalignment the cause of the outage?

A. No. The cracked rotor was the immediate cause of the outage. However, the misalignment apparently induced the cracking. As we discussed earlier, no specific part or cause was identified and all bearings and individual alignments were within tolerances.

IV. Plant Output Replacement Strategy

Q. How did PGE replace the lost output of Boardman during the outage period?

A. On October 23, 2005, when the plant was first forced out of service, PGE initially believed that the outage would be short-term and elected to replace the 370 MW energy from Boardman in the pre-schedule (day-ahead) or real-time markets. Because the market normally trades in blocks of 25 MW, PGE purchased 375 MW of replacement power.

After the rotor crack was discovered on November 18, 2005, Boardman notified PGE's Power Operations Department that the plant would be off-line for a significant period of time. As we noted in our UM 1234 testimony, once we knew that Boardman would be out for at least two months, we decided to purchase replacement power on a forward basis for the expected outage period. The risk of waiting to purchase in the pre-schedule or real-time markets was too great for our winter peak load months. When we purchased the replacement power, we 'flagged' the transaction. A summary of our transactions and our analyses is PGE Exhibit 106.

Q. Did PGE plan to perform maintenance at the plant during the period April 29 through May 27, 2006?

A. Yes. In my UM 1234 testimony, I noted that planned maintenance for the period was actually performed during the time that the plant was off-line. Because the maintenance was performed early, I expected that the plant would not need another planned outage until May 2007.

Q. Had not PGE already purchase replacement power for Boardman's expected May 2006 planned maintenance outage?

A. Yes. PGE had purchased some replacement power for the maintenance period. Since we expected that the plant would still be running during this period, PGE decided to sell this energy and credit the "Boardman outage" replacement power. PGE began selling 'May Boardman output' to the market in January and finished selling the last block of on-peak power during the last week of March.

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

A. Table 2 below shows the amount of replacement energy purchased by month for the deferral period (PGE Exhibit 106).

Table 2

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	-	-	-	-
Total	314,000	265,800	48,484	41,400	15,021	6,361

V. Prudency

Q. Did PGE operate the LP1 turbine in a reasonable manner?

A. Yes, each of the independent analyses confirmed that mis-operation did not cause the LP1 rotor to fail.

Q. Did PGE take reasonable actions to return the plant to operation as quickly as possible?

A. Yes. PGE chose a highly qualified vendor that could repair the rotor a month faster than Siemens. In addition, PGE flew the rotor to the east coast for repair and flew it back to Boardman to reduce the down time as much as possible. The overall costs of the outage were reduced by this course of action.

Q. Did PGE employ a reasonable replacement power cost strategy?

A. Yes. PGE considered its available options and decided to purchase from the market on a forward basis rather than to run a higher cost plant or to purchase from the volatile pre-schedule or real-time markets.

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VI. 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. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	Detailed Description of Outage – UM 1234 Testimony
102	Boardman Outage Timeline
103C	**Boardman Turbine Diagram**
104 A-H	Pictures Depicting the Repair
105C-A	**PGE Root Case Analysis Report**
105C-B	**Alstom Root Case Analysis Report**
105C-C	**Siemens Root Case Analysis Report**
105-D	M&M Engineering Overview of Repairs
106	Summary of Replacement Power Cost Purchases.

Table of Contents

I. Introduction

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

A. My name is Stephen Quennoz. I am Vice President, Power Supply. My qualifications 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.

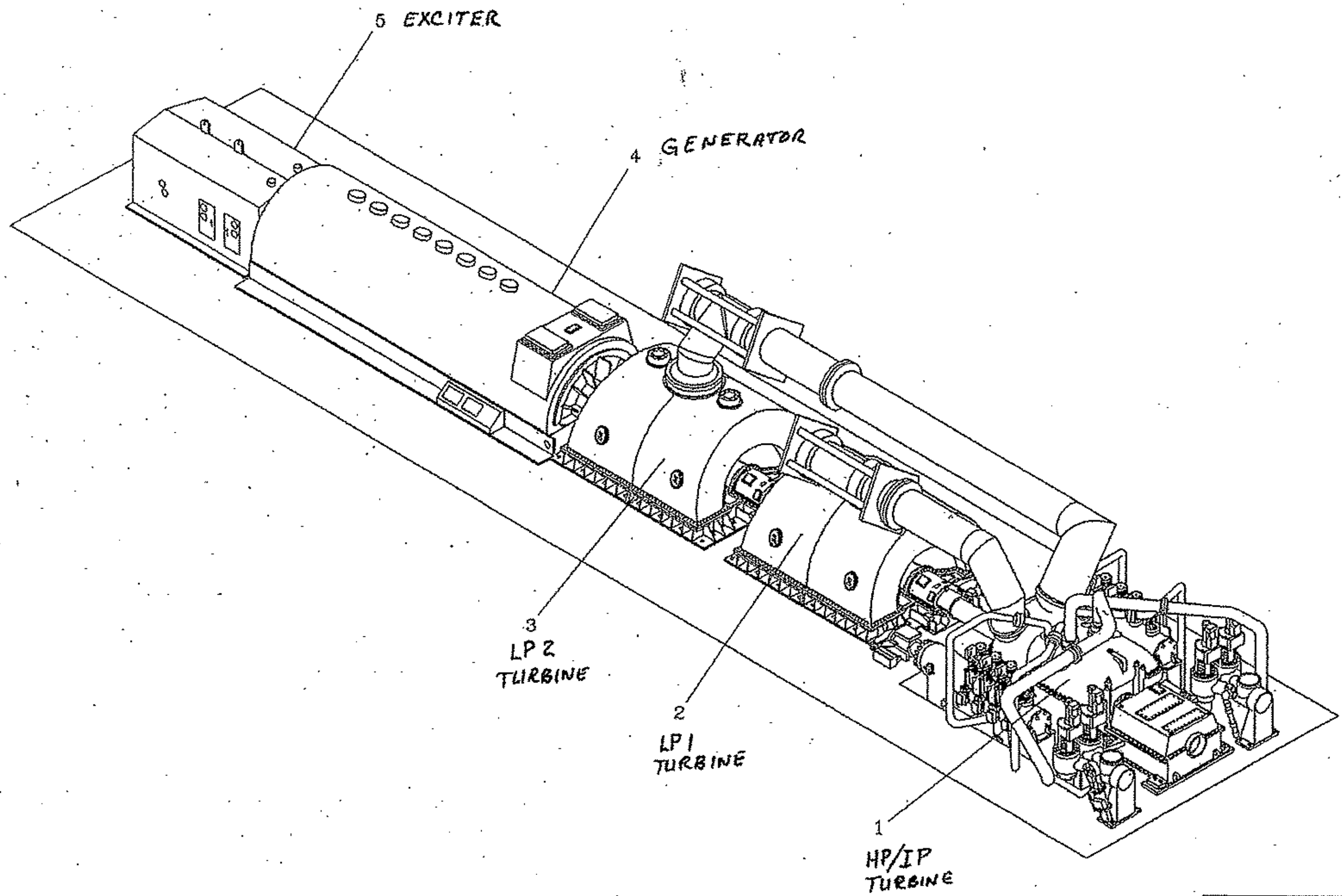
Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

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

6. LIST OF AUXILIARY SYSTEMS



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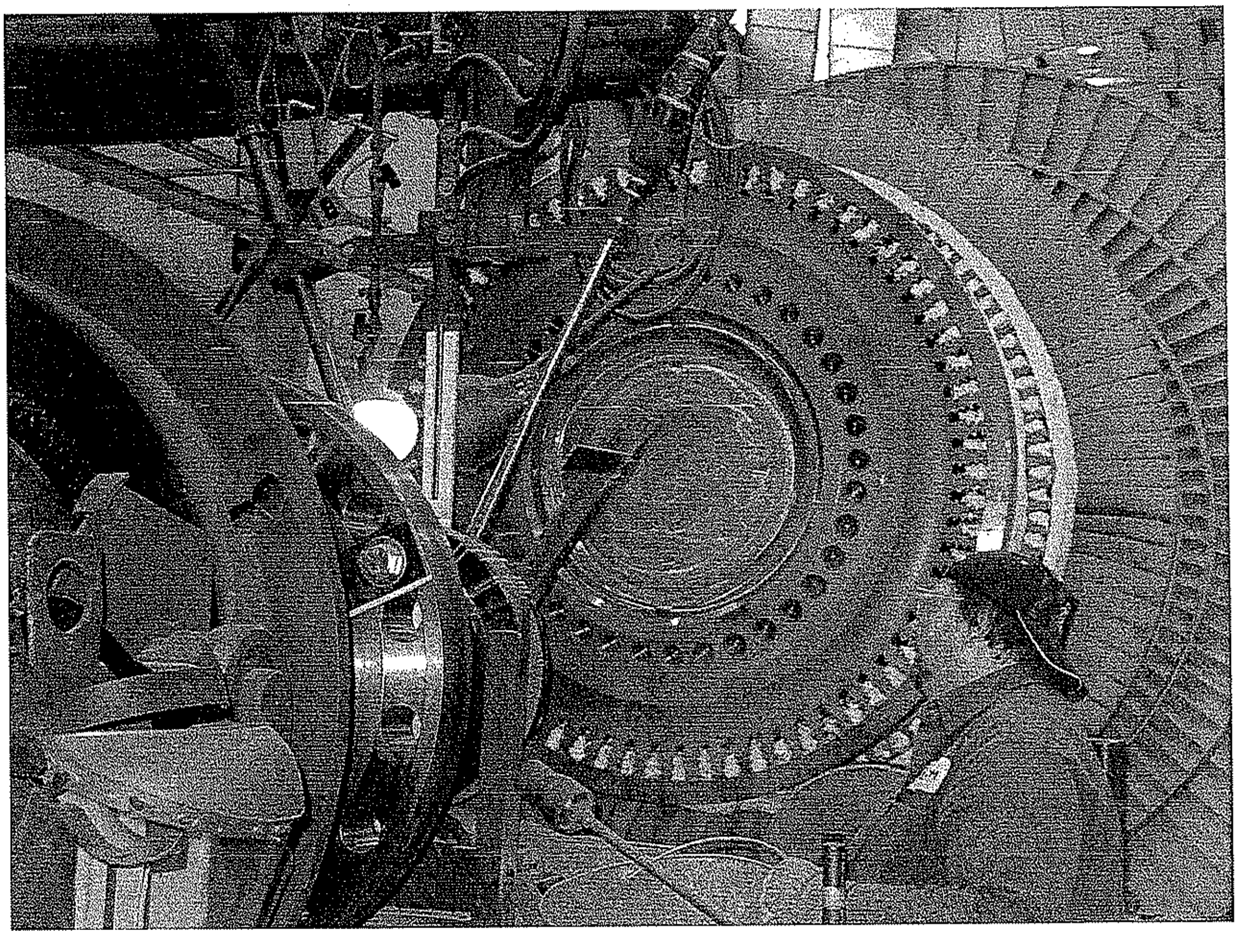
DATE	

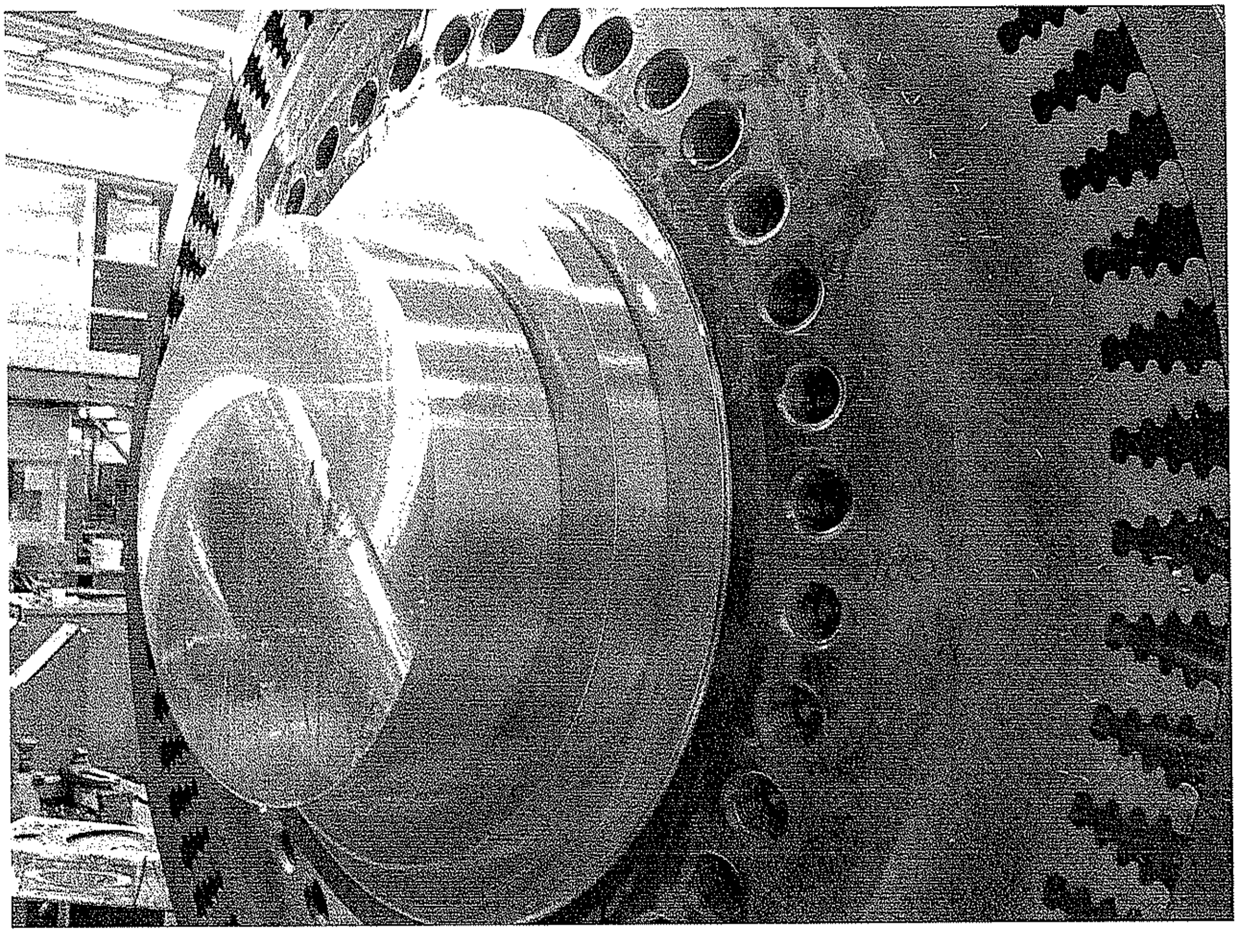
Figure 1. BOARDMAN 1

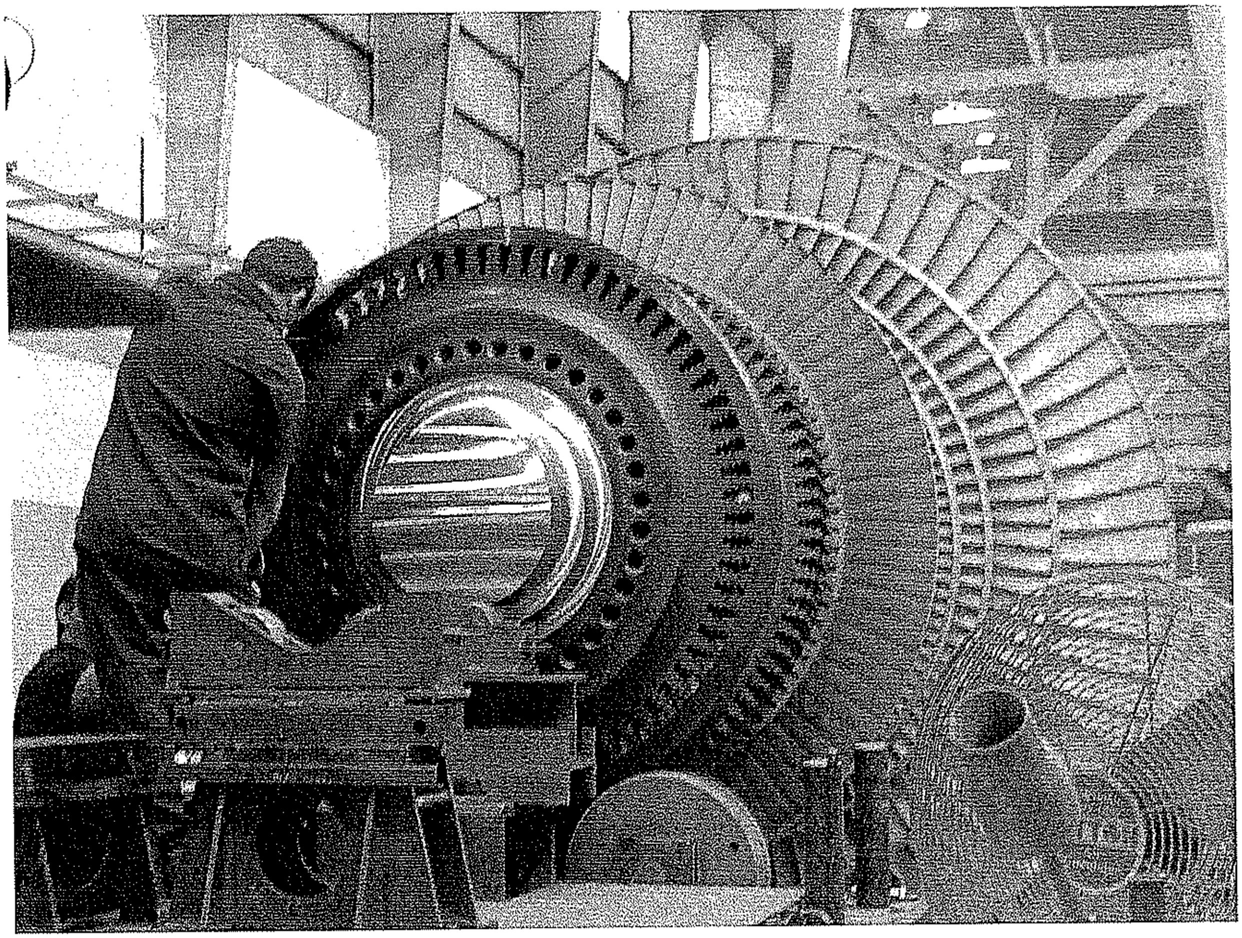
Exhibit 102

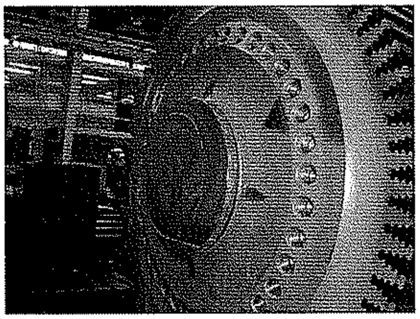
Boardman Outage Timeline

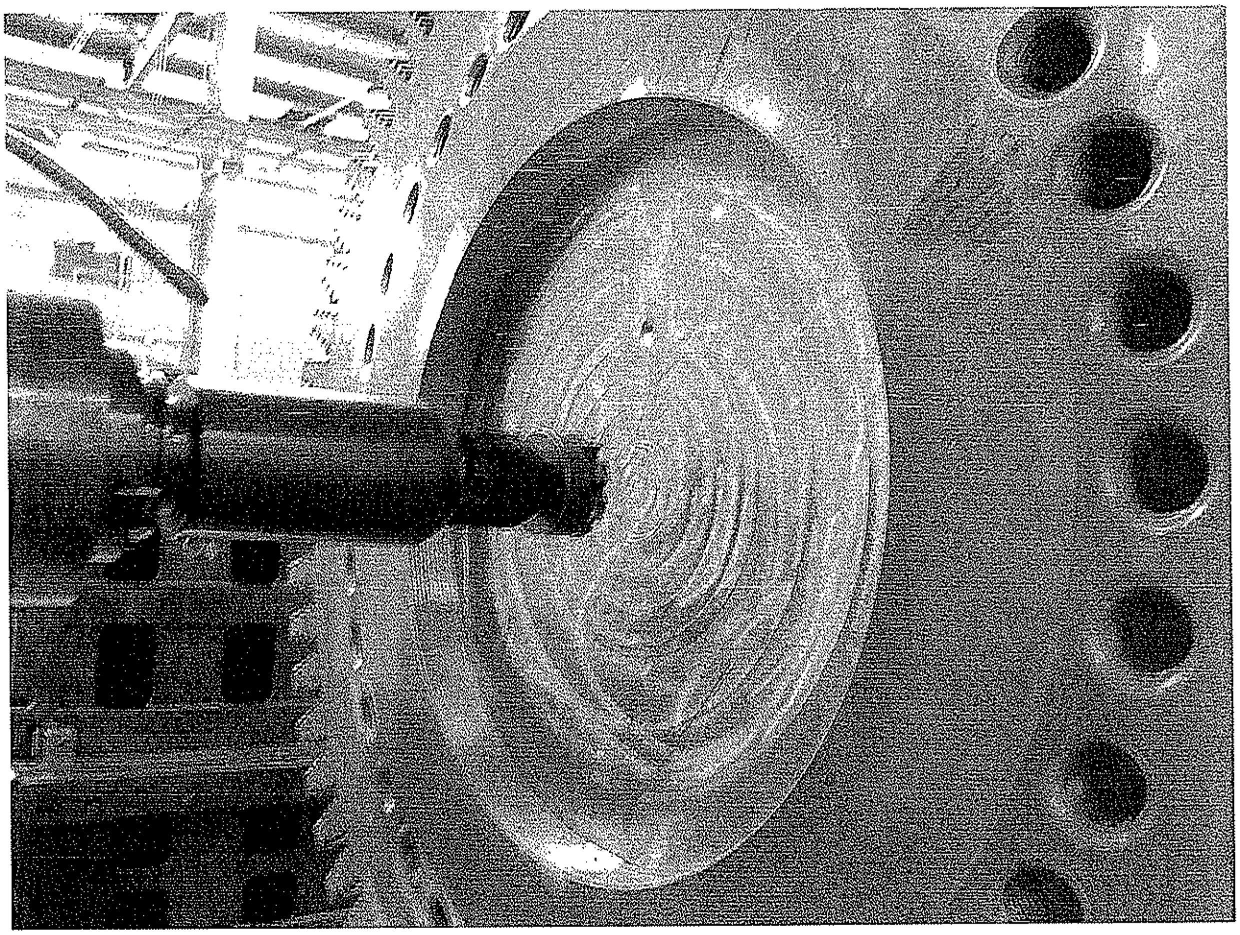
Event	Date
Vibration levels first noticed	July, 2005
Boardman taken off-line	October 22, 2005
Attempted restart	November 16, 2005
Rotor crack discovered	November 18, 2005
Deferral application filed	November 18, 2005
Transport for repairs	December 1, 2005
Received by Alstom	December 3, 2005
Repairs completed	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

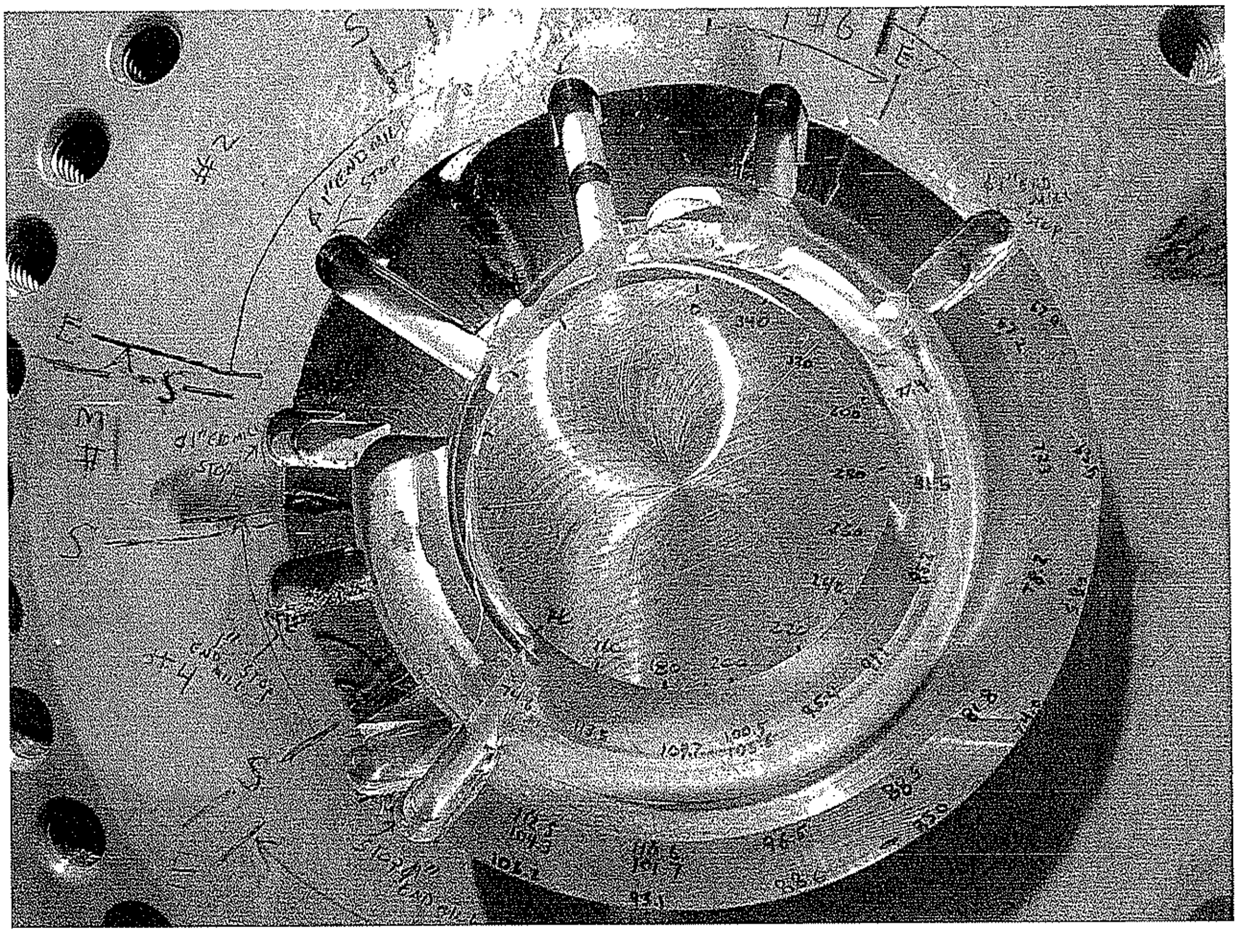


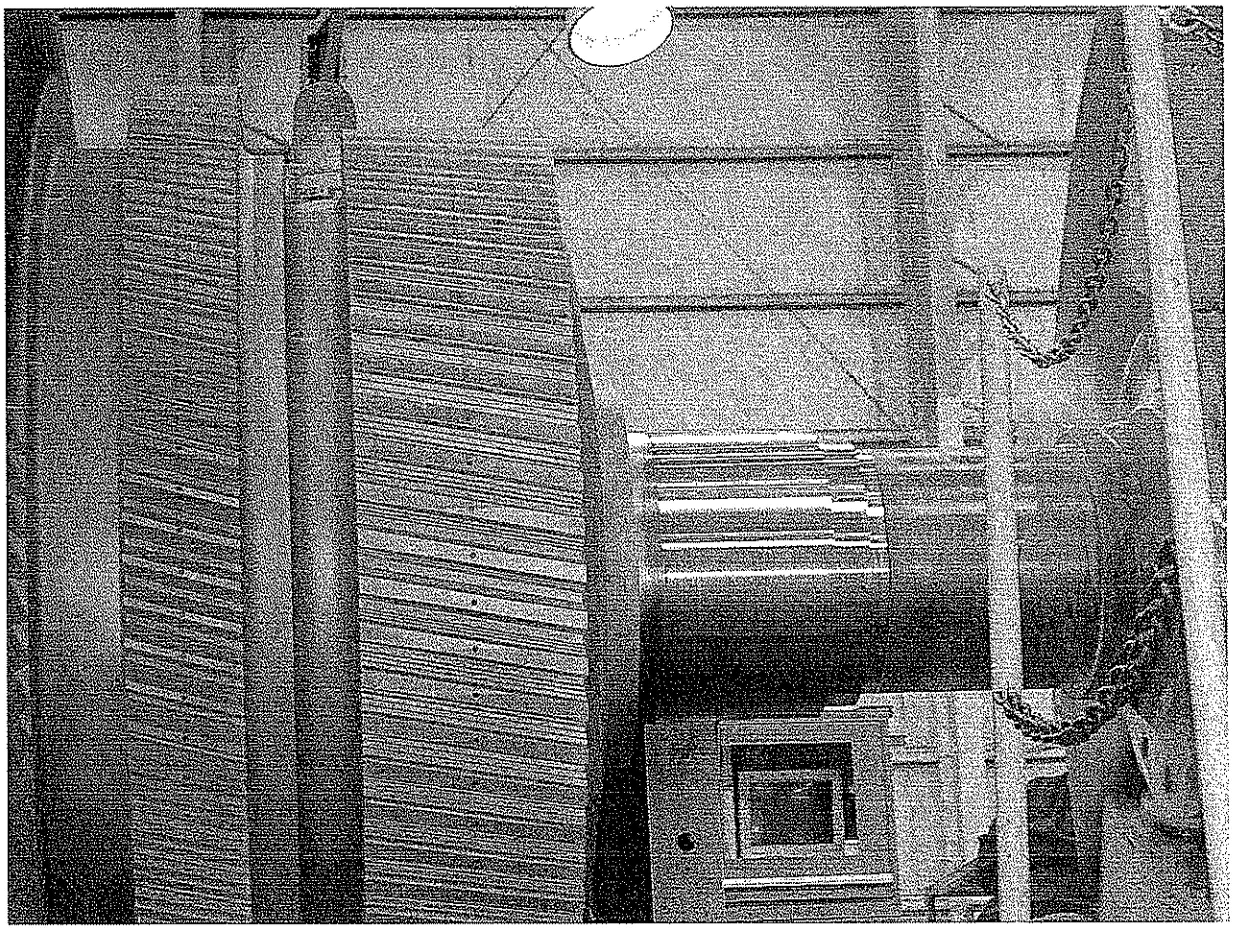


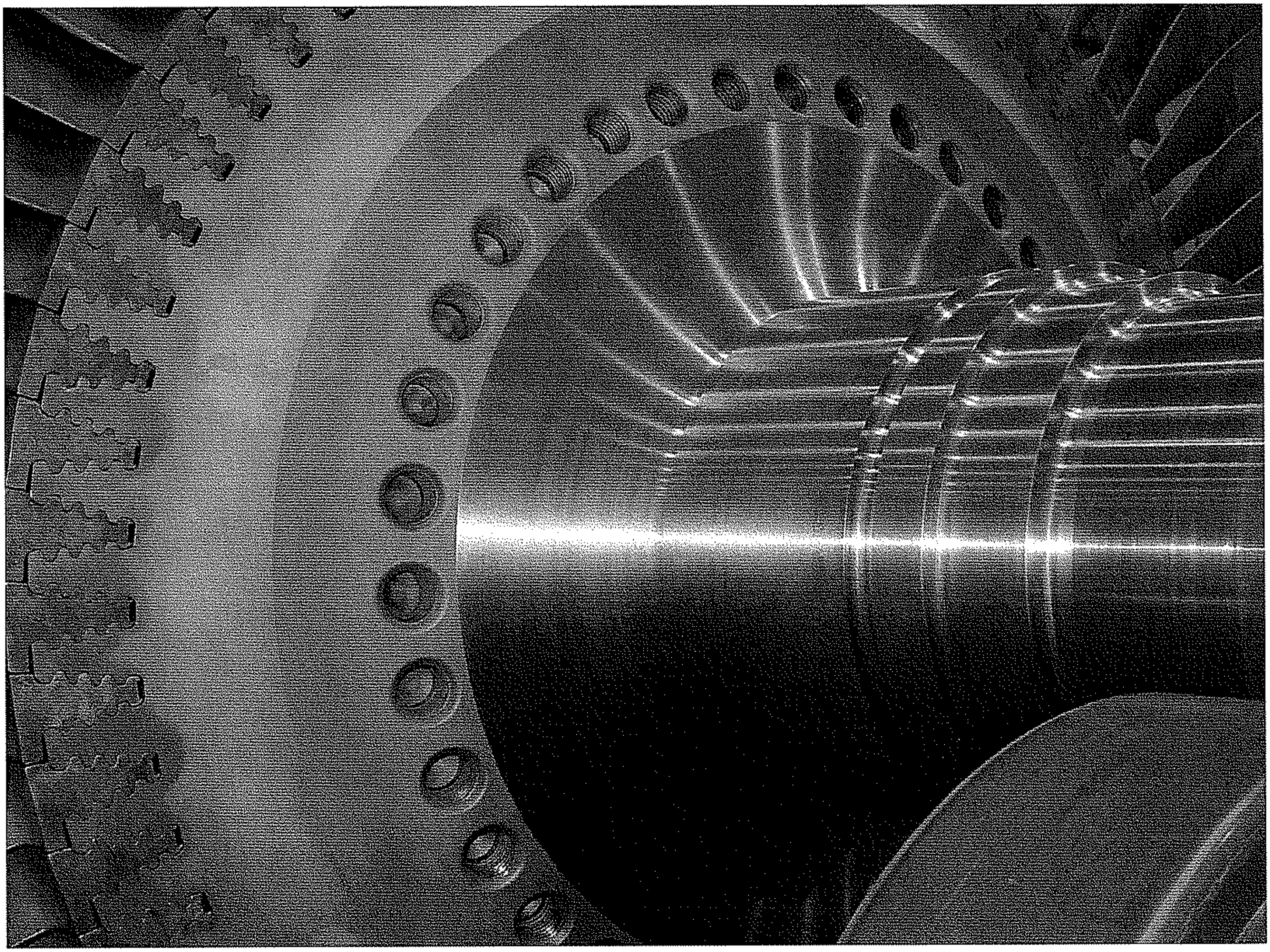












DCN 05-PGE.001

April 2, 2007

Ms. Janet Gulley
Project Manager
Power Supply Engineering and Strategy
Portland Gas & Electric
Portland, Oregon

Subject: Cracked LP Rotor Repair and Investigation

Dear Ms. Gulley,

As per your request, I am providing a summary of the work Mechanical & Materials (M&M) Engineering performed for Portland Gas & Electric relating to the repair and investigation of the LP cracked rotor. The rotor was reportedly found cracked after approximately 39,500 hours of operation.

On December 8, 2005, through December 9, 2005, M&M Engineering personnel went to the Alstom facility in Richmond, Virginia, to observe the removal of a crack that was running approximately 300 degrees around the circumference of the LP rotor. The removal had already started prior to the arrival of M&M Engineering personnel. As the crack was removed, examination of the fracture surfaces indicated the mode of cracking was fatigue with multiple initiation sites. After the eight pieces containing crack surfaces were removed, they were photographed and then shipped to the Alstom metallurgical laboratory in Chattanooga, Tennessee.

On December 16, 2005, December 17, 2005 December 20, 2005, and December 21, 2005, M&M Engineering participated in the laboratory investigation of the crack samples at the Alstom Chattanooga, Tennessee, facility. This included fractography using both a stereomicroscope and a scanning electron microscope. During the fractography investigation, fatigue cracking was verified with multiple initiation sites. Evidence of corrosion was only observed in one initiation site; however, corrosion pitting was observed in the vicinity of the steam gland transition radius. Small secondary cracks were also observed on the rotor surface in the vicinity of the initiation sites. The shape (large length to width ratios with serrated edges) of these very small cracks indicated the possibility of initiation at nonmetallic inclusions.

The samples were also examined using standard metallographic techniques. The microstructure was typical for rotor steels. One anomaly was observed near the surface of the rotor. Small clusters of nonmetallic inclusions were observed. These inclusions had the potential to affect fatigue initiation properties; however, the actual effect was unknown without fatigue testing.

Mechanical & Materials Engineering
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The chemistry and basic mechanical properties (tensile and Charpy) of the rotor material were tested. All of the properties were consistent with rotor steel and met the ASTM Standard for A470 Class 7 material.

On December 28, 2005, and December 29, 2005, M&M Engineering personnel went to the Alstom facility in Richmond, Virginia, to observe the LP rotor weld repair and review the procedure with Alstom's Rob Kilroy and Mike Jirninec. The repair to the Boardman rotor was being done appropriately. The repair plan was within prudent engineering practice and was being executed with good supervision and workmanship. M&M Engineering's only area of concern was the amount of manipulation and machining that was being done on the rotor with the weld in the "as-welded" condition. There is always a risk that a crack could develop in the weld deposit because it has low toughness without post weld heat treatment. However, Alstom performed frequent MT inspections that would have found cracking if it had developed. Given the time limitations for the repair, the PWHT delay made sense and was a commercial requirement.

M&M Engineering's initial assessment of the failure mechanism is fatigue with both bending and torsional stress components. Looking at the failure location, M&M Engineering was surprised the L-0 wheel radius was so tight. This was unusual for LP rotors. It was our understanding that Portland General Electric undertook a root cause analysis.

If you have any further questions or need more details, please do not hesitate to call.

Sincerely,

G. Mark Tanner

G. Mark Tanner, PE
Principal Engineer

Exhibit 106

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	-	-	-	-
Total	314,000	265,800	48,484	41,400	15,021	6,361

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Boardman Earnings Review

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alex Tooman
Patrick G. Hager

October 9, 2007

Table of Contents

I. Introduction

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

A. My name is Alex Tooman. I am a Project Manager for PGE. My primary responsibilities at PGE include regulated earnings reporting, revenue requirements including unbundling, and affiliated interest filings.

My name is Patrick G. Hager. I am Manager of Regulatory Affairs for PGE. My primary responsibilities include oversight of PGE's revenue requirement for rate filings as well as PGE's cost of capital including the Required Return on Equity (ROE).

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the Commission's conditions in Order 07-049 (UM 1234). These conditions approve PGE's request to amortize the deferral of replacement power costs associated with the first Boardman outage from November 18, 2005 through February 5, 2006. We find that a review of these conditions, and PGE's regulated results of operations for the twelve months ending September 30, 2006, demonstrate that PGE's earnings for the period fall significantly short of our authorized return on equity. Thus, PGE should be allowed to amortize the $26.4 million authorized for deferral by the Commission. PGE's proposal to collect the deferred amount is described in Section IV.

Q. How is your testimony organized?

A. First, we briefly discuss the conditions set forth in the Commission's order regarding the amount PGE could defer for replacement power costs associated with the Boardman outage. Next, we discuss the earnings test for the Boardman deferral, including the period used, specific adjustments made, and the results. We then briefly discuss the amortization test that must be applied to the deferral. Next we discuss the rate impact of amortizing the Boardman deferral. Finally, we present our qualifications.

Q. Do you address prudency issues in your testimony?

A. No. Prudency issues relating to the operation of the Boardman turbine and replacement power strategy are addressed in Exhibit 100 by Mr. Quennoz.

Q. Do you have any exhibits to your testimony?

A. Yes. We have six exhibits as shown on the List of Exhibits page at the end of this testimony.

Q. How is this docket different from UM 1234 that PGE filed on November 18, 2005?

A. OPUC Docket UM 1234 concerns the deferral of replacement power costs related to the first outage at the Boardman power plant from November 18, 2005, through February 5, 2006. In that docket, the Commission found that PGE could defer up to $26.4 million for subsequent recovery, subject to demonstrating that PGE's actions were prudent. This docket concerns PGE's actions both before and during the Boardman outage.

Q. Please summarize PGE's actions before and during the deferral period.

A. Boardman originally was taken off-line on October 23, 2005, because of increasing vibration levels in the low pressure turbine 1 (LP1). After attempting to restart the plant on several occasions, PGE and its contractors, including Siemens, decided to take the plant off-line. Initially, PGE expected the outage to be short, but after further analyses, it became clear that the turbine would have to be disassembled and then shipped to the East Coast for repair. To offset the lost generation, we decided to purchase replacement power because it was less expensive than producing it at our Beaver plant, which was the next available option. At the same time, given the expected magnitude of the replacement power costs, we filed a deferred accounting application (UM 1234).

Q. How would you summarize the Commission Order from UM 1234?

A. On February 12, 2007, the OPUC issued Order 07-049, which allowed PGE to defer up to $26.4 million of the $42.8 million of replacement power costs that PGE incurred. In that Order, the Commission held that the event was a "scenario risk" and, therefore, was unforeseen and unique (Order 07-049, pg. 10, PGE Exhibit 202). Furthermore, the Commission held that the Boardman Outage had a "material effect on PGE's financial condition, and conclude[d] that the Boardman Outage satisfies deferral discretionary criteria."

II. PGE's Earnings Test

Q. Is PGE required to provide an earnings test as part of its request to amortize deferred power costs?

A. Yes. ORS 757.259 (Exhibit 203) requires the Commission to review a utility's earnings prior to allowing for amortization of deferred balances.

Q. Please describe the earnings test.

A. The earnings test is the second phase of cost recovery that a utility pursues. The first step is determining the amount of appropriate costs that the utility can defer. This first step was the UM 1234 proceeding. Now, having determined the amount that the utility can defer, we must determine how much, if any, of the authorized deferred costs the utility will be allowed to amortize in rates.

Q. What were PGE's earnings without collecting the deferral?

A. Without collecting the $26.4 million, PGE's regulated adjusted ROE for the 12-month period that includes the Boardman outage is only 3.55%, far below its authorized 10.5% ROE for the period. *See* PGE Exhibit 204. If PGE collects the $26.4 million, its regulated adjusted ROE will rise to only 5.14% over the earnings test period, still far below its authorized ROE. Thus, PGE should be allowed to collect the full amount authorized by the Commission.

A. Calculating Recoverable Deferred Power Costs

Q. How did PGE calculate its recoverable deferred power costs?

A. PGE first calculated the deferral amount by determining replacement net variable power costs (NVPC) for the 105-day outage period, ending February 5, 2006. This amount is approximately $45.0 million. We then adjusted these power costs, per Order 07-049, by updating Boardman's forced outage rate and removing line losses. This reduces the replacement NVPC from $45.0 million to $42.8 million.

Second, PGE applied the sharing mechanism approved in Order No. 07-049, which includes a $13.4 million "dead band," with an additional 90/10 sharing for amounts up to the allowed recovery (i.e., customers pay 90% of the replacement power costs).

As shown in PGE Exhibit 205, application of the bands and sharing mechanism to the adjusted replacement power costs results in PGE incurring approximately $45 million in excess power costs and a recoverable deferral of approximately $26.4 million.

Q. Has PGE applied interest to the deferred balance?

A. Yes. PGE applied its authorized cost of capital to the deferred balance. The total interest for the period through December 31, 2007, is approximately $5.0 million. Added to the $26.4 million deferral, the total amount is approximately $31.4 million. PGE Exhibit 206 provides the balance of deferred power costs, including all relevant interest computations.

B. Calculating the Earnings Test and Adjustments

Q. What is the period for review of PGE's earnings?

A. The period is October 1, 2005, through September 30, 2006.

Q. Why did PGE select this period for the earnings test?

A. The earnings period needs to encompass the entire deferral period. We chose this period because it covered the deferral period and it provides a review of the most recent level of earnings possible. Therefore, we believe that this period includes the most representative earnings for review.

Q. Was there a planned maintenance period in the spring and were those costs included?

A. This period actually represents a benefit and not a cost. PGE had sold all the power it had purchased for the maintenance period by the end of March as discussed in PGE Exhibit 100. This revenue was included in the replacement power costs for Boardman.

Q. What standards did PGE apply to develop the earnings test?

A. Generally, the standards that apply to the earnings test are:

- Commission decisions from UE 82 (Order No. 93-257), UE 115 (Order No. 01-777), and UM 1234 (Order No. 07-049).
- Staff letter on Results of Operations Reports dated March 25, 1992.

Q. How did PGE perform the earnings test for the Boardman deferral?

A. PGE performed the earnings test similar to the method we use to prepare our annual Results of Operations Report. To do this, we applied accounting and regulatory adjustments (based on the UE 115 rate case) to our actual operating results. This calculation produces an ROE that represents our regulated adjusted results. We then compared this regulated ROE to our authorized ROE.

Q. Did PGE make any changes to the standard method used to prepare the Results of Operations Report?

A. Yes. Based on Commission Order No. 93-257, referenced above, we did not normalize power costs during the review period. Instead, we only controlled for the second Boardman outage, which occurred from February 6, 2006, to May 31, 2006, and for which PGE agreed to hold customers harmless. To accomplish this, PGE estimated power costs by applying a forced outage rate equal to (1 – 0.935) during Boardman's second outage. This results in an earnings test that assumes Boardman was operating from February 6 through May 31 at a performance level consistent with that used to set rates during the period. It is also consistent with PGE's rebuttal testimony in Docket UM 1234.

C. Earnings Test Results

Q. Is PGE "under-earning" if it does not recover the deferred balance?

A. Yes. Without deferral recovery, PGE's earned ROE on a regulated adjusted basis is 3.55%. This amount is well below the 10.5% ROE authorized in UE 115.

Q. Is PGE "over-earning" if it recovers the full deferred balance?

A. No. With recovery of the deferred balance, PGE's earned ROE on a regulated adjusted basis is 5.14%. This achieved level of ROE is also well below the 10.5% ROE authorized in UE 115 and well within a reasonable range of ROEs for deferral recovery.

III. Results of 3% Test for Amortization

Q. What is the 3% test?

A. ORS 757.259 requires that the total rate impact of the amortization of deferred balances in any year cannot exceed 3% of the utility's revenue from the previous year.

Q. Does PGE's proposal for amortization of the deferred balance of power costs and customer credits pass the 3% test?

A. Yes. Revenues for the period are forecast to be $1.6 billion (UE 188, UE 192). Because PGE proposes to offset the $26.4 million deferral amortization with credits due to customers, total amortizations remain unchanged as a result of the offset.

IV. Rate Impact

Q. What is the rate impact associated with amortizing the Boardman deferral?

A. PGE anticipates that there will be no rate impact from the Boardman deferral because we propose to offset the deferral with other credits due to customers.

Q. Which credits does PGE propose to use as offsets?

A. The primary offsets will be $20 million from the Trojan Nuclear Decommissioning Trust, per Commission Order No. 07-015, plus $11.6 million from a deferral associated with the independent spent fuel storage installation (ISFSI) tax credits. PGE also proposes to apply two other categories of deferrals to the Boardman balance as summarized in PGE Exhibit 206:

- Residual balances of eleven prior deferrals to clear them off PGE's books and refund the net balance to customers.
- Unamortized balances of two small deferrals that in total have minimal rate impact. This also clears them off PGE's books and applies the net balance to customers.

Q. What balances do these amounts represent?

A. As of December 31, 2007, the approximate balances will be: $31.4 million for the Boardman deferral, $31.6 million credit for the two primary offsets, $1.1 million credit for the eleven residual deferral balances, and $1.3 million for the two small unamortized deferrals. PGE will adjust the ISFSI credit balance to net the balances to zero. The remaining ISFSI balance will continue to earn interest for future refund to customers. PGE Exhibit 206 provides details of each account's balance as of December 31, 2007.

Q. Is PGE's proposal for collecting the deferred power cost balance reasonable?

A. Yes. PGE prudently incurred the amounts requested for amortization and PGE has deferred variable power costs consistent with the Commission Order No. 07-049. The results of an earnings test indicate that PGE would significantly under-earn if the deferred balance is not collected and that PGE would still under-earn with collection of the deferred balance. PGE’s proposal to offset amortization of deferred power costs with amortization of customer credits minimizes the rate impact on customers. Finally, PGE’s proposed amortization schedule does not violate the 3% test.

V. Qualifications

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

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

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

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975. I received a Masters of Arts degree in Economics from the University of California at Davis in 1978, with a concentration in public finance, international trade and finance, and applied econometrics. I've completed all course work and examinations towards my Ph.D. I joined PGE in 1984 as a business analyst. I have also taught financial markets at the undergraduate and graduate levels at Portland State University. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). I have also passed all three levels of the Chartered Financial Analyst (CFA) exam and received my charter in December 2000.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	UM 1234 PGE Exhibit 300 Drennan-Tinker-Hager
202	Order 07-049
203	ORS 757.259
204	Summary of Earnings Test
205	Excess Power Costs and Deferrable Amount
206	Deferral Balance and Offsets

Table of Contents

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

ORDER NO. 07-049

ENTERED 02/12/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1234

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY	)	ORDER
	)	
	)	
Application for Deferred Accounting of Excess Power Costs Due to Plant Outage.	)	

DISPOSITION: DEFERRAL AUTHORIZED IN PART

I. PROCEDURAL BACKGROUND

On November 18, 2005, Portland General Electric Company (PGE or the Company) filed, with the Public Utility Commission of Oregon (Commission), an application for deferred accounting (Application) of $45 million dollars for excess power costs incurred from November 18, 2005 through February 5, 2006, due to what the Company called an "unexpected and extraordinary" outage at its Boardman generating plant (the Boardman Outage). The Application seeks deferral of the difference between the variable power costs for the Boardman plant, as established in the applicable resource valuation mechanism (RVM) proceedings[1], and replacement power costs incurred during the 105-day Boardman Outage.

On February 28, 2006, a prehearing conference was held in Salem, Oregon for the above captioned docket. PGE filed direct testimony on April 14, 2006. Response testimony was filed on June 1, 2006, by Commission Staff (Staff), the Industrial Customers of Northwest Utilities (ICNU) and the Citizens' Utility Board of Oregon (CUB). On July 17, 2006, PGE filed rebuttal testimony. A hearing was held on August 3, 2006, but parties agreed to waive cross-examination of all witnesses. Consequently, the hearing was administrative in nature only. Subsequent motions to admit testimony by PGE, Staff, ICNU and CUB were granted. On September 7, 2006, Staff and parties filed opening briefs. On September 21, 2006, Staff and parties filed reply briefs.

On July 21, 2006, PGE filed a motion requesting that the docket be designated as a major proceeding, and that oral argument be held. The motion was granted on July 24, 2006. Oral argument was held in Salem on October 3, 2006.

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[1] PGE's variable power costs for calendar year 2005 were set in Docket No. UE 161; PGE's variable power costs for calendar year 2006 were set in Docket No. UE 172.

II. FINDINGS OF FACT

On October 23, 2005, PGE's Boardman plant began a prolonged, forced outage. The Boardman Outage was caused by a performance problem with one of the facility's low-pressure turbines (LPT1). The LPT1 was designed and manufactured by Siemens Westinghouse Power Corporation, and installed in June of 2000. After installation of the LPT1, Boardman output increased by approximately 35 MW for the same energy input, thereby improving the efficiency output of the plant by approximately seven percent. LPT1 operated without serious problems through approximately the first half of its first ten-year interval for major maintenance. Plant engineers noticed vibrations occurring at one of the two bearings for the LPT1 in July 2005, however, and by October of that year, vibration levels were severe enough to warrant taking the unit off line. Inspection ultimately revealed a crack in the rotor for the LPT1, resulting in a need to remove the rotor, repair and reinstall it. As the repaired rotor was being placed into service, a generator rotor failed, causing a second outage on February 6, 2006. As the second outage is not at issue in the Application, PGE states that requested deferral period is limited to the time period beginning on November 18, 2005, and ending on February 5, 2006 (the Deferral Period).

Initially assessing the Boardman Outage to be short-term, PGE's power operations group replaced 375 MW of plant output with wholesale power purchases in day-ahead or real-time markets. When the Boardman Outage was determined to likely extend over multiple months, PGE evaluated replacement options, and concluded that forward wholesale power prices were below the generating cost of PGE's only power plant with available output during the months of December 2005 and January 2006. On November 18, 2005, PGE filed an Application requesting that the Commission authorize deferral of approximately $45 million dollars in costs that were incurred to replace Boardman's output, between the date of the Application, and February 5, 2006, the date PGE deemed the Boardman Outage to be concluded. Replacement power expenses for the Deferral Period were recorded in Federal Energy Regulatory Commission (FERC) accounts 555 and 501 for Purchase Power and Fuel Expenses, respectively.

Boardman had been scheduled for a planned maintenance outage from April 29, 2006 through May 27, 2006. PGE performed the scheduled maintenance during the forced outage. As PGE had already purchased replacement power for the scheduled maintenance outage, PGE was able to resell that energy in the forward market, using the revenue from this sale to partially offset replacement energy costs during the forced outage period.

III. DISCUSSION

A. Does PGE's Deferral Application Satisfy Legal and Discretionary Criteria?

1. Positions

a. PGE

Under subsection 2(e) of ORS 757.259[2], PGE seeks deferral of the Boardman Outage replacement cost expenses, rather than seeking an interim rate increase. PGE asserts that its Application satisfies both prongs of the statutory test as it would: 1) minimize the frequency or rate changes; and 2) match benefits received by ratepayers with costs borne by those same ratepayers. PGE asserts that an interim rate increase could have been supported based on PGE's poor financial results for the 2005 calendar year. (PGE's net income for 2005 was $64 million, down from $92 million in 2004, and PGE earned an estimated 6.3% return on equity (ROE). At the time of the Application, PGE projected even worse results for 2006.) PGE asserts that using deferred accounting instead of interim ratemaking is preferable due to the temporary nature of the Boardman Outage. PGE also argues that deferral of costs associated with the Boardman Outage will match the costs and benefits associated with the replacement energy better than other ratemaking approaches.

PGE also argues that the Application merits an exercise of Commission discretion to grant it. PGE explains that in exercising its discretion under the deferred accounting statute, the Commission considers the type of event that gives rise to the deferral application, and the magnitude of the harm resulting from the event. PGE asserts that the Boardman Outage is a scenario event, having not just a material financial impact on PGE's earnings, but a substantial impact.

In determining the nature of an event, PGE indicates that the Commission considers whether the event was: 1) included in test-year assumptions used to set rates; and 2) reasonably foreseeable as happening in the ordinary course of events. PGE points to the Commission's recent statement in Docket UM 1147, where deferred accounting principles were adopted:

> 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

[2] Subsection 2(e) of ORS 757.259 permits the deferral of "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."

> foreseeable as happening in the normal course of events, or not likely to have been capable of forecast.[3]

Under the above criteria, PGE concludes that the Boardman Outage was neither modeled, nor could have been foreseen.

PGE explains that the Commission forecasts PGE's power costs for a given year using a rolling average of thermal plant availability for the four preceding years. PGE states that PGE's 2005 power costs rates were based on the following equivalent forced outage rates (EFOR) for Boardman for the years 2001 through 2004:

Year	Modified EFOR
2004	11.51%
2003	4.21%
2002	8.12%
2001	2.89%

As these forced outage percentages do not include outages as significant as the Boardman Outage, PGE concludes that the Boardman Outage was not modeled. PGE cautions that the Boardman Outage must be evaluated on an annual basis, as it began in 2005 but extended into 2006. PGE analogizes the Boardman Outage to the shutdown of its Trojan nuclear plant, and indicates that parties have agreed in the past that such extended plant outages are examples of scenario risks meriting deferral of the associated replacement power costs.

PGE deems the Boardman Outage to be unique in terms of its cause and duration, and therefore, unforeseeable. Indeed, PGE observes that the Boardman Outage could not have been reasonably forecast to begin in 2005, or at any time during the normal course of the plant's expected use. PGE calls the Boardman Outage a once in every 100 year event. Looking at national data recorded by the North American Electric Reliability Council (NERC), PGE asserts that a 105-day plant outage is extremely rare, as only 51 out of 21,415 outages over the past twenty years have lasted 105 days or longer, which is just 0.238% of all outages occurring nationally. PGE also observes that deferral of replacement power costs for the Boardman Outage is justified because the financial impact of the outage will not average out over time, should the Boardman Outage be excluded when forecasting future power cost rates.

PGE explains that the relevant question, with regard to characterizing an event as a stochastic or scenario risk, is not whether test-year forecasting makes assumptions about the type of event involved, but whether the pertinent test-year forecast assumed or predicted the particular event. Pointing to docket UM 1070, PGE asserts that the Commission denied PGE's application to defer costs associated with hydro conditions because the relevant forecasts assumed hydro conditions within the range of the conditions at issue. In comparison, PGE argues, the relevant forecasts for the Boardman Outage were based on

[3] Order No. 05-1070, 7.

Boardman's availability over specific four-year periods that did not include any outage of a length even close to the Boardman Outage that is at issue now.

Regardless of how the Boardman Outage is characterized as an event, PGE asserts that its financial impact is large enough to warrant deferral of replacement power costs. PGE assesses the total excess power cost impact associated with the Boardman Outage to be $59 million, representing a 355 basis points effect on ROE. PGE calculates the costs eligible for deferral to be $45.7 million, representing a 273 basis points effect on ROE.

PGE also asserts that the ultimate financial harm to the Company is greater, due to the negative tax consequences associated with the excess power costs, as a result of Senate Bill (SB) 408. PGE contends that the impact of the Boardman Outage is made more significant by the recently passed legislation which modifies the way income taxes are recovered in rates. PGE asserts that for each dollar of excess power costs the Company incurs, customers will realize a tax benefit of 40%. PGE explains that the fixed ratio approach used under SB 480 captures the tax consequences of actual variances from test-year forecasts, without recognizing the variances themselves.

b. Staff

Staff concludes that the Boardman Outage satisfies legal and discretionary criteria. In Staff's assessment, deferral of certain Boardman Outage costs will appropriately match the costs that PGE incurred to provide power to customers with the benefits of that power. In response to ICNU, Staff indicates that a minor delay between the outage and the recovery by deferral of related costs is practically necessary due to the length of the deferral process.

Staff also agrees with PGE that the 105-day forced outage for the Boardman plant is an extraordinary event, and calls the level of financial impact on PGE significant. Staff concludes that the Boardman Outage is of a type, and magnitude, to warrant the Commission's exercise of its discretion to authorize the deferral of certain associated costs.

Contrary to PGE's position that the Boardman Outage is a scenario risk, Staff evaluates it as a stochastic risk, because the underlying event—a forced outage—is foreseeable, and the frequency of forced outages is quantifiable. Staff considers the financial impact of the Boardman Outage to be substantial, however, and therefore, great enough to warrant deferral. Although Staff recognizes that the Commission has not established fixed criterion to identify "substantial financial impact," Staff observes that the Commission has previously identified a financial impact of 250 basis points on ROE to be substantial. Staff assesses the Boardman Outage costs eligible for deferral to have a financial impact of approximately 255 basis points on PGE's ROE. Staff calls PGE's position, that the Boardman Outage is a scenario risk, irrelevant. Staff asserts that regardless of whether the Boardman Outage is identified as a stochastic or scenario risk, its financial impact is significant enough to merit deferral treatment.

c. CUB

CUB deems the Boardman Outage to be extraordinary, and acknowledges that deferral of associated costs will "technically" minimize rate changes, and will temporally allocate costs. CUB regards the Boardman Outage as difficult to classify as a stochastic or scenario risk, but concludes that it must be considered an "unusual" or "unique" event. Consequently, CUB deems it appropriate to treat the Boardman Outage as a scenario event. CUB also deems the financial impact of the Boardman Outage, estimated to be between 255 and 273 basis points on PGE's ROE, to be significant enough to justify deferral. CUB also takes the position that the Boardman Outage is not an event that should be included in a four-year average of a utility's forced plant outages, for the purposes of setting of future rates.

CUB supports PGE's request to recover actual replacement power cost, rather than net system variable power cost, but with the caveat that this method of quantification should be used consistently to determine deferral amounts. CUB recalls that deferral costs associated with the outage of PacifiCorp's Hunter plant were based on net system power cost variation. CUB expresses concern that the utilities should not be permitted to select the methodology that benefits the utilities most, resulting in the greatest amount of deferred monies. CUB asserts the net system variable power cost methodology used in a bad hydro year allows a utility to recoup costs not directly resulting from the deferral event, while use of the actual replacement power cost methodology in a good hydro year allows the utility to keep benefits associated with additional hydro production. For example, CUB explains that PGE's proposed quantification method for determining the deferral amount associated with the Boardman Outage will not capture PGE's use of additional hydro production to offset Boardman's lost generation, or to make additional power sales in the market. CUB recommends that the Commission direct utilities to always use actual replacement power cost to determine a deferral amount.

d. ICNU

ICNU argues that PGE's deferral request is neither legally authorized, nor worthy of the Commission's exercise of discretion. Noting that the Commission has previously indicated that deferred accounts should be used sparingly, and recognizing that the deferral of excess power costs may upset the allocation of risk in ratemaking, ICNU urges the Commission to deny PGE's Application. ICNU also accuses PGE of trying to "game" recovery of the Boardman Outage costs by combining deferred accounting with manipulation of forced outage rates.

ICNU asserts that the Commission's distinction between stochastic and scenario events focuses on whether a risk is predictable and capable of being modeled in rates, rather than whether an event is "rare". ICNU classifies the Boardman Outage as a stochastic risk, because forced outages are expected and forecast. ICNU explains that PGE establishes power costs based on assumptions about forced outages for all thermal generating plants, including Boardman. The forced outage rate recently used in PGE's rate model uses a four-year rolling average of actual outage rages. Rates established in PGE's 2005 and 2006 RVM proceedings assume a 6.5 percent outage rate, representing approximately 24 days of outage on an annual basis. ICNU argues that PGE's multiple generating plants increase the odds of an extended forced outage. ICNU asserts that PGE fails to demonstrate that the length of the Boardman Outage justifies treating it differently from other forced outages.

Even if the duration of the Boardman Outage is considered rare, ICNU argues that PGE's 2005 and 2006 power costs included forced outage rates reflecting annual plant outages of equal or greater magnitude than the 2005 Boardman Outage. PGE responds, however, that ICNU relies on data representing annual forced outage rates, and not an event-by-event itemization of forced outages. PGE also observes that an outage of a coal plant, which typically operates below market prices, has greater financial impact than an outage of a gas plant, which usually operates nearer market prices.

ICNU also discounts data from NERC indicating that only 0.24 percent of all outages nationally recorded by NERC in the last twenty years lasted as long as the Boardman Outage. Observing that almost 90 percent of the outages recorded lasted only five days, ICNU argues that under PGE's construct, every outage lasting "longer than a couple of days would be treated as a scenario event."

ICNU argues that PGE's experience with multiple extended forced outages in the past thirty years belies the argument that the Boardman Outage was unforeseeable. ICNU points to an extended outage for Boardman when the plant first became operational in the early 1980s, followed by an extended outage and the eventual decommissioning of the Trojan plant in the 1990s, and then followed by a six-month outage for PacifiCorp's Hunter 1 plant in 2000. ICNU also points out that the Boardman plant experienced not one, but two extended outages in the last two years—the outage at issue in this proceeding, and a subsequent outage caused by failure of the same LPT1 turbine—for a total outage period of over 150 days. ICNU observes that a history of four extended outages for PGE thermal generating plants in a period of 26 years undermines PGE's assertion that an extended outage for a plant such as Boardman is not expected to occur in the lifetime of the plant.

ICNU also argues that plant outage variances from forecast do balance out, as PGE regularly experiences actual outage rates that are substantially less than the assumed outage rates in power costs, allowing PGE on occasion to collect more in rates than actual power costs. ICNU asserts that there is a distribution of actual outage rates ranges that are both higher and lower than the assumed outage rates upon which power costs are based.

Concluding that the Boardman Outage is a stochastic event, ICNU argues that the financial impact of the outage is insufficient to warrant deferral. ICNU asserts that the Commission's standard of whether an event has a substantial financial impact, if the event impacts the utility's earnings beyond a reasonable range, typically measured as 250 basis points on ROE. ICNU argues that Commission precedent establishes that "250 is an appropriate measure of the minimum financial impact necessary to allow deferral of a cost arising from a stochastic risk that already has been modeled in rates."[4]

[4] ICNU Opening Brief, 10.

ICNU calculates that replacement power costs for the Boardman Outage total $42.6 million, which translates to a 254 basis points impact on PGE's ROE. ICNU observes that this impact barely exceeds the 250 basis points deadband on ROE used to measure the substantiality of impact. In any case, PGE asserts that PGE's overall earnings, and factors affecting these earning, such as hydro conditions and gas and electric prices, must also be considered.

Indeed, ICNU argues that events other than the Boardman Outage significantly contributed to PGE's earnings in 2005 and 2006. ICNU points to increases in other expenses, the establishment of a $10 million reserve for refunds of Multnomah County Business Income Taxes, and lower hydro output as significant negative impacts on PGE's 2005 earnings. ICNU testified that 2005 hydro conditions had a 149 basis points impact on PGE's 2005 earnings. Consequently, ICNU estimates that the Boardman Outage, on its own, has only a 210 basis points effect. ICNU also states that PGE's 2005 10-K indicated that the 11 percent increase in PGE's average variable power costs "was largely offset by both a reduction in total system load and a $24 million decrease related to the amortization of costs deferred under [PCAs] in effect during 2001 and 2002."[5] ICNU concludes that a comprehensive analysis of PGE's 2005 earnings indicates that the impact of the Boardman Outage is not as significant as claimed by PGE. In any case, ICNU also alleges that PGE's claim that its 2005 earnings were less than 2004 is misleading, because there is evidence that PGE's $64 million in net income in 2004 is roughly equivalent to the $60 million and $66 million that PGE earned in 2003 and 2002, respectively.

Finally, ICNU argues that the deferral of replacement power costs during the Boardman Outage will neither minimize the frequency of rate changes, nor match costs and benefits for ratepayers. If the financial impact of the Boardman Outage is barely substantial, it is not severe enough to warrant interim rate relief, ICNU argues. ICNU also observes that rates will be changing shortly anyhow, because PGE filed a rate case that seeks rate changes in the near future.

2. Resolution

As we have discussed in several past orders, we determine whether a deferral application should be granted with a two-stage review. During the first stage, we examine whether a deferral application is authorized by law, pursuant to ORS 757.259. To be authorized, the facts of a proposed deferral must indicate that the requested deferral will either minimize the frequency of rate changes, or appropriately match the costs borne by, and the benefits received by, ratepayers.

PGE initially took the position that if we decided not to grant the Application, we could still address the Boardman Outage costs by taking the Boardman Outage into account when setting future rates in UE 180.[6] We have already determined in UE 180 not to

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[5] *Id* at 19, citing ICNU/102, Falkenberg/7.
[6] On March 15, 2006, PGE filed Advice No. 06-8, an application for a general rate increase, that was docketed as UE 180.

take the latter action, having removed the hours in the Deferral Period from the forced outage hours used to calculate a forced outage rate in that docket.[7] Having taken the Boardman Outage into account in forecasts for future rates would have indirectly affected rates for the next five years, while deferral of the Boardman Outage costs would directly impact rates for a much shorter period of time. We conclude that the proposed deferral better aligns benefits and costs and is, therefore, legally authorized. Under ORS 757.259, it is unnecessary to consider whether the proposed deferral would also minimize rate fluctuations.

We turn to the second stage of our deferral review to evaluate whether we should exercise our discretion to grant the requested deferral. In this stage, we must evaluate whether the Boardman Outage should be characterized as a stochastic or scenario event, and assess the event's financial impact on PGE. Although Staff suggests that we need not classify the Boardman Outage, we deem it important to do so. In Order No. 04-108, upheld by Order No. 04-357, we first explained that the exercise of our discretion involves our consideration of two interrelated factors: the type of event giving rise to the deferral, and the magnitude of the amount to be deferred. We also indicated that if a deferral application was based on an event deemed to be a stochastic risk, deferral was warranted only if the financial magnitude of the event was substantial, whereas deferral of a scenario event is appropriate if the financial effect of the event is material. A full and complete evaluation of PGE's deferral application requires that we consider both factors.

In Order No. 04-108, we explained that a stochastic risk can be predicted to occur as part of the normal course of events, whereas a scenario risk is not susceptible to prediction or quantification. In Order No. 05-1070, we further explained that we consider whether a deferral event was modeled in rates. If an event was modeled in rates, we evaluate whether the event was within a foreseen range of risk, or whether extenuating circumstances were involved that rendered the event unforeseeable. If the event was not modeled in rates, we assess whether it was otherwise foreseeable in the normal course of business.

As part of the ratemaking process, we model plant outages. We agree with PGE, however, that we must determine whether the Boardman Outage *itself* was foreseen, or was predictable within the forecast range of probability. In other words, as plant outages are modeled in rates, the question we must ask to determine if deferral is warranted for costs associated with the Boardman Outage is: Was the Boardman Outage within a foreseen range of risk?

In setting a utility's rates, this Commission takes into account a forced outage rate generally determined by the average availability of the utility's thermal plants for the preceding four years.[8] Here, the rates applicable to this request for a deferral were established, in part, using a forced outage rate determined in PGE's last general rate proceeding, Docket No. UE 115.[9] To determine the foreseeability of the Boardman Outage, we conclude it is appropriate to examine whether the scope of the event was within a

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[7] *See* Order No. 07-015 at 15.
[8] The Commission may decide to not include, or otherwise adjust for, extraordinary outages when determining the EFOR for a particular year.
[9] *See* Order No. 01-777.

reasonable range around this previously determined forced outage rate. In other words, we look to determine whether the event falls within a reasonable deviation range around the forced outage rate.

Utilizing this approach, we find that PGE's rates in effect during the requested deferral period did not take into account a plant outage as significant as the Boardman Outage. We find that the nature, and the 105-day duration of the Boardman Outage are unique, and that its occurrence is outside of the foreseen range of risk for forced outages. Indeed, in PGE's recently concluded rate proceeding, we held that the unique nature of the Boardman Outage warranted its removal from the inputs used to determine a forced outage rate. [10] Consequently, we deem the Boardman Outage to be a scenario risk.

This finding is consistent with our decision in Order No. 04-108. There, we distinguished between hydroelectric conditions that fell within a foreseeable range of hydro availability, and a plant outage that was far outside the range of forecasted risk for forced outage. In that order, we identified the serious outage of PGE's Trojan nuclear plant that was the subject of two deferral cases as a scenario risk. We stated:

> In the Trojan deferral cases, UM 445 and UM 529, we were dealing with a paradigm or scenario risk. While rates are typically set using four year average forced outage rates to forecast NVPC, the duration and cost of the Trojan outages were not within the range considered when we set base energy rates. The Trojan shutdown was not a normal forced outage, and the risk of premature decommissioning was not reflected in base energy rates. By contrast, the 2003 hydro year at issue here is within the range considered in normalizing hydro availability. [11]

Although the Boardman Outage was not as severe as the Trojan outage, the Boardman Outage was significant and, like the Trojan outage, was clearly outside the range of outages considered when rates were established for 2005 and 2006. Again, we conclude that the Boardman Outage is properly classified as a scenario risk.

In Order No. 04-108, we indicated that deferred accounting treatment is appropriate for costs related to scenario risks, if the financial impact of the event is material. Staff and all parties agree that the financial impact of the Boardman Outage is at least a few points over 250 points on PGE's ROE. PGE, Staff and CUB also agree that a financial impact over 250 points on ROE is not only material, it is substantial. Consequently, we deem the Boardman Outage to have a material effect on PGE's financial condition, and conclude that the Boardman Outage satisfies deferral discretionary criteria.

[10] *See* Docket No. UE 180, Order No. 07-015 at 15.
[11] Order No. 04-108 at 10.

B. What Replacement Power Costs Are Eligible for Deferral?

1. Positions

a. PGE

PGE identifies two categories of costs associated with the Boardman Outage: 1) Costs associated with energy purchases, valued either at market or contract price, to replace Boardman output. (PGE estimates Boardman output lost during the deferral period to be 383 MWa for 2005, and 380 MWa for 2006); and 2) Costs avoided due to the Boardman Outage, such as unused coal and transportation, and including the incremental costs of production, as established in the appropriate RVM forecasts.[12] The latter category of costs offsets the first. PGE assumes line losses of 1.9 percent for both categories.

The following simplified calculation explains calculation of the cost associated with a single hour of the Boardman Outage:

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

PGE originally calculated the total net cost of the Boardman Outage for the Deferral Period to be approximately $45.4 million. PGE estimated that the financial impact of this amount would be a reduction in PGE's ROE by 270 basis points, not taking into income tax effects associated with implementation of Senate Bill 408.

b. Staff

Staff challenges PGE's calculation of costs for the Boardman Outage, finding two basic flaws with the calculation, and several minor errors. Staff recalculates the total net cost of the Boardman Outage during the Deferral Period to be approximately $42.8 million, $2.6 million less than originally requested by PGE.

Staff asserts that PGE's calculation is flawed because it overstates the amount of energy replaced, as PGE's calculation is based on the full capacity rating for the Boardman plant, instead of the plant's derated capacity. Staff explains that PGE already recovers a certain level of replacement power costs in rates, based on an assumed forced outrage rate of 6.5 percent. Staff states that existing rates assume that the Boardman plant is available 93.5 percent of the time, providing 358 MW of generation in 2005, and 355.5 MW in 2006, as determined in prior RVM proceedings. Staff argues that these amounts should be used when calculating the Boardman Outage costs, not PGE's numbers which are based on the fully-rated capacity of Boardman.

Staff also criticizes PGE's calculation because it includes a line loss adder. Observing that PGE does not include such an adder in rate models, Staff finds the 1.9 percent adder on the calculation of replacement costs to be inconsistent and inappropriate.

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[12] Incremental costs are $11.48 and $12.44 per MWh for 2005 and 2006.

Staff also identifies minor errors in PGE's calculation, as follows: 1) PGE erred in calculating the daily on- and off-peak average price or quantity of pre-scheduled power purchases (typically by assigning an average price or quantity for each day, when daily prices or quantities were actually different) on November 11, 2005; November 13-14, 2005; November 20-21, 2005; and November 24-28, 2005; and 2) the cost for 1,200 MWh of prescheduled energy was inappropriately included as replacement power. In addition, Staff determined that PGE incorrectly calculated savings from avoided maintenance by: 1) using the rated capacity of the Boardman plant and the line loss adder; 2) included 800 MWh of forward market sales that do not appear to have occurred for April 29, 2006; and 3) using the Company's February 3, 2006, forward electricity price curves, instead of actual day-ahead index prices.

c. ICNU

ICNU agrees that PGE's calculation of replacement power costs is flawed because it assumes that the Boardman plant's full capacity of 383 MW was lost during the Boardman Outage. ICNU asserts that the rate model used to set rates for the years of 2005 and 2006 assumed that the Boardman plant's available output would be 358 MW. ICNU concludes that PGE's base rates cover the difference of 25 MW between Boardman's assumed availability and its full capacity. ICNU recalculates Boardman replacement costs to be $42.6 million.

d. CUB

CUB agrees with Staff and ICNU's identification of calculation flaws by PGE. CUB concurs that PGE miscalculated outage costs by using a rated capacity for Boardman of 380 and 383 MW for 2005 and 2006 respectively, instead of the derated capacities of 358 MW and 355 MW that were used, respectively, to calculate PGE's power rates for 2005 and 2006. CUB accepts Staff's calculation that costs related to the Boardman Outage total $42.8 million.

e. PGE's Response

PGE agrees with all of Staff's proposed modifications to the calculation of the Boardman Outage costs, resulting in a total of $42.8 million, although PGE's agreement with one proposed modification is conditional. PGE agrees that replacement costs for the Boardman Outage should be calculated based on the reduced capacity rating for Boardman of 93.5 percent, but only if future forecasts, conducted in other proceedings, such as UE 180, do not assume that Boardman will be available at full capacity.

PGE asserts that the treatment of this deferral application is inextricably related to the method used to determine Boardman's availability for forecasts of future net variable power costs (NVPC). Since the 1980s, the Commission has used a rolling, four-year weighted average of actual forced outage rates to determine thermal availability for NVPC forecasts. PGE characterizes this methodology as not only an objective means to forecast an unknowable number, but also as a risk allocation mechanism. PGE explains that better than forecast thermal plant operations will result in benefits to customers, while worse than expected operations will result in higher revenues for the utility. As an example, PGE notes that the Boardman plant performed particularly well in 2001, with an EFOR of 2.89 percent, with that figure being included in PGE's 2006 RVM as an input for the current 6.5 percent Boardman forced outage rate, or 93.5 percent availability factor.

PGE considered not requesting deferral of Boardman Outage costs. Instead, PGE argued that it could have relied on trying, in UE 180, to include the Boardman outage in the rolling, four-year average methodology to forecast future power rates. PGE considered this approach inferior to deferral, however, due to the following two reasons, among others: 1) as PGE did not originally know the duration of the outage, PGE could not determine the likely impact on future rates; and 2) PGE was concerned that basing future rates on the outage would result in rates that did not reflect actual costs.

When the duration of the outage was known, PGE considered it reasonable to take into account the Boardman Outage when forecasting future rates in UE 180. PGE observed that the outage's span over two calendar years mitigates the forecast effect. PGE originally asked the Commission to decide, in this docket, which regulatory tool to use to address the Boardman Outage.

2. Resolution

Our role in this proceeding is threefold: 1) to evaluate whether PGE's deferral application should be granted, and if so: 2) to determine the amount that is eligible for deferral; and 3) to decide whether all eligible costs, or some subset, should be actually deferred. It is not within the scope of this proceeding to determine how future power costs are forecasts and rates set. In any case, we already decided, in UE 180, to remove the hours in the Deferral Period from forced outage hours used to calculate a forced outage rate in that docket.[13] .

With this issue dispensed with, we find no disagreement among Staff and parties that there is a total of $42.8 million in replacement power costs associated with the Boardman Outage, for the defined deferral period, that are eligible for deferral. We approve this amount.

[13] *See* Order No. 07-015 at 15.

C. What Eligible Replacement Power Costs Should Be Actually Deferred?

1. Positions

a. PGE

PGE argues that the Commission need not impose a deadband or other sharing mechanism if PGE's deferral request is granted. PGE asserts that the statutory authorization for deferrals does require the amount eligible for deferral to be shared, and points out that the Commission approves many deferrals without imposition of a sharing mechanism, including the deferrals of: PGE's anticipated 2005 Oregon state income tax kicker; pollution control tax credits; information technology costs; intervenor funding; and advertising. Indeed, PGE observes that the only deferred cost items that have ever been subject to sharing requirements are power costs. PGE asserts that regulatory policy should treat all deferrals the same.

PGE refutes the precedential value of the application of a deadband and a sharing mechanism in UM 995. PGE asserts that the Commission never intended its decision in that case to be the standard applied in other cases. Rather, PGE observes that the Commission recognized the situation—*i.e.*, the California energy crisis, near record drought, cold weather, and a catastrophic plant outage—to be extraordinary. PGE also points to numerous factual differences between the Boardman Outage and the situation in UM 995: 1) the UM 995 deferral period lasted almost 12 months, whereas the requested deferral period for Boardman is less than three months; 2) the UM 995 deferral was global in nature, taking into account all variations in power costs, whereas the requested deferral only addresses the outage of the Boardman plant; 3) a 250 basis points on ROE deadband in UM 995 allowed PacifiCorp to recover approximately 60 percent of excess power costs, whereas application of the same deadband to the Boardman Outage would disallow all but one percent of PGE's excess power costs.

PGE notes the severe consequences of applying a deadband or sharing mechanism. Although Staff and CUB both agree that the costs associated with the Boardman Outage should be deferred, PGE estimates that if any of the sharing mechanisms recommended by Staff and CUB are applied, PGE would recover only 0.74 to 5.46 percent (or less[14]) of the $45.7 million that PGE asserts was incurred to provide service to customers during the outage. As Staff also recommends that the Boardman Outage be ignored for future forecasting purposes, PGE argues that the effect of Staff's position is to essentially disallow the deferral, as ICNU recommends.

If the Commission applies a regulatory device, such as a deadband or sharing mechanism, when determining the total amount of Boardman replacement costs to be deferred, PGE argues that it must consider the impact of SB 408 when doing so. PGE states

[14] PGE indicates that CUB has publicly stated, since its testimony, that PGE should recover less than $1 million. Thus, PGE's hypothesis that using Staff's recommended recovery of $905,000, together with CUB's proposed sharing band of 70/30, PGE could recover only up to 1.4% of replacement power costs.

that the Commission indicated in Order No. 06-532, which adopted rules to implement SB 408, that it would consider the impact of SB 408 in other ratemaking proceedings. PGE asserts that the thresholds suggested by Staff, CUB and ICNU do not take into account tax implications to PGE of cost and revenue variances. As the calculation of taxes collected by a utility under SB 408 does not factor in variances from test-year forecasts, PGE explains that ratepayers realize a tax benefit of 40% on each dollar that PGE incurs in excess power costs. PGE argues that to compensate for this impact, the Commission must adjust any deadband or sharing mechanism that is applied, or increase the amount deferred by PGE's effective tax rate.

If the Commission does not authorize deferral of excess power costs related to the Boardman Outage, or implements one or more sharing mechanisms that effectively negate any recovery of Boardman Outage costs, PGE argues that the Commission must take into account the Boardman Outage when forecasting future rates. PGE prefers that the Commission use deferred accounting to allow PGE to recover prudently incurred replacement power costs, but argues that it is contradictory to deny deferred accounting for such costs on the basis that rates already take into account forced outages such as the Boardman Outage, yet not include that outage when modeling and forecasting future power costs.

PGE explains that since 1984, test-year forecasts in general rate cases of net variable power costs have assumed thermal generating plants would be available, based on a weighted, rolling average of availability for the preceding four years. As PGE filed a general rate case with a test year of 2005 (Docket No. UE 180), the inclusion of the Boardman Outage in plant availability statistics is at issue in that proceeding. PGE takes the position that for future forecasting purposes, the Boardman Outage should be excluded only if the Commission authorizes deferral of replacement power costs.

b. Staff

Although Staff concludes that $42.8 million in Boardman Outage costs are eligible for deferral, Staff argues that only a small portion of these costs should actually be deferred. Staff recommends that the Commission impose sharing mechanisms that would divide responsibility for the outage costs between ratepayers and shareholders. The sharing mechanisms recommended by Staff would:

1. Require shareholders to absorb 100 percent of the excess power costs in a deadband equivalent to 250 of ROE;

2. Shareholders absorb 50 percent of the excess power costs in a sharing band between 250 and 400 of ROE; and

3. Shareholders absorb 10 percent of the excess power costs beyond 400 ROE.

Staff asserts that these sharing mechanisms are consistent with Commission precedent since 2001 for power cost deferrals. Staff observes that the Commission first imposed such sharing mechanisms for deferred power costs in Docket UM 995. In that case, Staff asserted that the following three principles justified the application of a sharing mechanism to deferred costs:

1. Utilities typically bear the risks and rewards of revenue and cost changes between rate cases, and should be protected only to the extent that cost changes are truly extraordinary;

2. Risks should not be completely shifted from the utility to its customers. It is appropriate to share even the risks of extraordinary cost changes;

3. The utility should receive incentives to minimize costs.

In Docket UM 995, Staff also argued that sharing mechanisms allow extraordinary costs to be shared with ratepayers, while capturing the "normal business risk" that a utility is generally exposed to between rate cases.

Staff agrees with PGE that any sharing mechanism applied to Boardman Outage costs could be adjusted to account for the effects of implementation of SB 408. To address the effects described by PGE, Staff suggests that the Commission adjust the deadband in Staff's proposed sharing mechanism by the tax effects for 2006, when the SB 408 automatic adjustment clause takes effect.

c. CUB

CUB also recommends that appropriate sharing mechanisms be implemented, observing that PGE fails to convincingly argue why such mechanisms should not be applied. CUB points to several other instances where a deadband of 250 basis points has been instituted, and various sharing bands applied (*e.g.*, 50/50 sharing band for power cost variances between 250 and 400, and a 75/25, 80/20 or 90/10 band for costs above 400.[15] For deferral of Boardman Outage related costs, CUB recommends that the Commission institute a 250 basis points on ROE deadband, with a sharing band of 70/30 applied to all costs outside the deadband. Using Staff's corrected excess costs of $42.8 million, application of CUB's proposed band would result in PGE customers absorbing up to $655,000 of such costs. CUB also takes the position that the Boardman Outage is a catastrophic plant failure that should not be included in a utility's four-year average.

CUB acknowledges that rules adopted in AR 499, pursuant to SB 408, may have consequences on any mechanisms applied to a deferral. CUB asserts that its testimony in UE 180 is relevant here. In UE 180, CUB stated, with regard to the interplay of SB 408 and sharing mechanisms, the following:

> We recognize that the application of Senate Bill 408 may create a reason to reevaluate the appropriate magnitude of a

[15] CUB/100, Jenks/8, referencing Docket Nos. UM 995, UM 1008/UM 1009, UM 1007 and UE 165.

> deadband and sharing bands. In the past, a deadband and sharing bands were pre-tax values, and the utility then got a tax deduction, which reduced the impact of these bands. With the implementation of SB 408, these tax deductions will most likely be incorporated in the SB 408 automatic adjustment clause, and so no longer act to mitigate the amounts in a deadband and sharing bands. As the rules implementing SB 408 are not yet finalized, and as SB 408 is likely to face both a tough legislative session as well as legal challenges, we have designed a mechanism without taking into account SB 408. Once SB 408 is fully implemented, the Commission may wish to revisit a deadband or sharing bands such that the impact on the utility and the customers remain the same. CUB does not oppose redrawing the deadband and sharing bands so that post-SB 408 bands have the same after-tax impact as pre-SB 408 bands. CUB Opening Brief at 9, citing UE 180 CUB/200/Jenks/23.

CUB supports adjustment of proposed sharing mechanisms to account for SB 408 implications.

d. ICNU

Although ICNU's primary position is that PGE's deferral application should not be granted, ICNU argues if the Commission grants PGE's deferral application, the Commission should apply a 250 basis points on ROE deadband and a 50/50 sharing band. ICNU asserts that a 250 basis points on ROE deadband reflects the level of power cost variability risk that a utility assumes between rate cases, as the Commission has imposed in prior rate cases,[16] while the 50/50 sharing band represents a fair allocation of the additional risk, consistent with prior Commission decisions.[17] ICNU adds that the deadband and sharing band should be applied, regardless of whether the Commission deems the Boardman Outage to be a stochastic or scenario risk. ICNU observes that in UM 995, the Commission applied the same devices to the deferral of costs associated with a scenario event.

Although ICNU points to the UM 995 case as an example of the Commission's application of a 250 basis points on ROE deadband and additional sharing bands to a deferral, ICNU argues that application of these regulatory devices were not based on the specific circumstances of that docket. ICNU asserts that the Commission simply adjusted the outermost band of the sharing band to reflect the circumstances of that case. Thus, ICNU argues that the Commission should apply the 250 basis points deadband now if it grants PGE's deferral application, and although ICNU proposes a 50/50 sharing band,

[16] ICNU refers to Order No. 01-420 at 5, 28; Order No. 01-231, Appendix A, at 4; Order No. 01-307, Attachment A, at 1; and Order No. 04-108 at 9.
[17] ICNU refers to Order No. 01-420 at 28-29.

ICNU acknowledges that the Commission should tailor the sharing mechanism to the circumstances of the deferral.

ICNU disputes PGE's contention that the Boardman Outage is analogous in any way to the Trojan shutdown. ICNU asserts that a shutdown and decommissioning of a nuclear facility is far different than a temporary outage at a coal plant. In any case, ICNU observes that deferrals associated with the Trojan plant were authorized fifteen years ago, before the Commission significantly elaborated on its deferred accounting policy.

ICNU also opposes adjusting the amount to be deferred in any way to account for SB 408. Although ICNU acknowledges that the Commission observed that it would take into account the tax effects associated with SB 408 when considering issues such as power cost adjustment mechanisms, ICNU argues that a power cost deferral is far different. ICNU also asserts that the Commission determined in Order No. 06-532 that it would be contrary to the legislature's intent to adopt an earnings test, or deferred account, that would effectively offset the SB 408 automatic adjustment clause. ICNU believes that adjusting the Boardman Outage deferral would indirectly accomplish this result.

2. Resolution

The variability of power costs is expected, such that we anticipate some divergence between actual and forecast costs. Ratemaking has been traditionally designed with the understanding that utilities are responsible for absorbing such power cost changes between rate proceedings.[18] To the extent that the variance between forecast and actual power costs is extraordinary, however, we have several regulatory tools available, including deferral, to address such costs. When using regulatory tools such as a deferral, however, we must determine when excess power costs—i.e., actual costs above forecast—are truly extraordinary. We must also decide how to allocate responsibility for costs that are eligible for deferral between a utility's shareholders and its ratepayers, in order to ensure that ratepayers are responsible only for extraordinary costs and that utilities receive incentives to minimize costs. Having already determined that at least some costs associated with the Boardman Outage are extraordinary and eligible for deferral, we turn to the latter decisions.

In this proceeding, Staff, CUB and ICNU argue that regardless of the nature of the Boardman Outage—whether stochastic or scenario—there is a normal range of business risk associated with power cost variances that PGE must absorb before any costs are deferred. They contend that the measure of this normal band of risk is a 250 basis points deadband on ROE, as the Commission has applied in past cases, such as UM 995. However, PGE responds, and we agree, that employing the 250 basis points deadband on ROE to a scenario event such as the Boardman Outage would be a new application of the deadband.

[18] Our discussion of PGE's power costs risks reflect risks associated with ratemaking in effect when PGE filed the Boardman deferral application, prior to implementation of a Power Cost Adjustment Mechanism (PCAM) pursuant to Order No. 07-015. We expect that the PCAM will significantly alter future power cost risks and rewards for PGE, and will change how they are addressed, eliminating the need for power cost deferrals.

The 250 basis points deadband on ROE originated in UM 1008/UM 1009, and was again applied in UM 995 as a sharing mechanism to allow PacifiCorp to recover power cost changes deemed extraordinary. In Order No. 04-108, entered in UM 1071, we articulated the distinction between stochastic and scenario risks, and explained that a 250 basis points deadband on ROE was also useful as a measuring stick to determine whether the financial impact of a stochastic event is substantial enough to warrant deferral in the first place. In Order No. 07-015, entered in UE 180, we applied an adjusted 150 basis points on ROE deadband[19] as an explicit measure of normal business risk.

We must decide whether it is appropriate to apply a measure of normal business risk to a scenario risk such as the Boardman Outage. If so, then we must decide what the appropriate measure is. As we discussed above, we consider the Boardman Outage to be a scenario risk because we find the scope of the Boardman Outage to be outside of the range of foreseeable forced outages. This method of identifying a scenario risk differs significantly from an alternative method, whereby we classify an event as a scenario risk because we find that it was not susceptible, in the first place, to prediction or quantification. The fundamental distinction between these two classifications of scenario risk is the relevance of the concept of normal risk. In the first method, there is a range of normal risk that must be deviated from before an event will be considered a scenario risk; in the second, there is no range of risk to evaluate.

If an event is deemed a scenario risk because it is outside a range of normal risk, we find that it is appropriate to apply a measure of normal risk when allocating, for deferral purposes, the costs associated with the event. We recognize, however, that the proposed 250 basis points deadband on ROE may not be the appropriate measure of normal risk to be applied in such a case. Rather, we find that the measure of normal risk applied to a scenario event should be contextual, reflecting the pertinent range of risk, and considering whether the scenario event is isolated, or combined with another scenario event or other extenuating circumstances.

For the Boardman Outage, we find the appropriate measure of normal risk to be the range of forseeability we earlier defined as a reasonable deviation range around the pertinent forced outage rate. We find that PGE should not be allowed to defer costs that would likely be associated with an outage within this range of normal risk. However, as parties did not present evidence in this proceeding that would allow us to explicitly calculate this level of costs, we find it appropriate to approximate the financial impact of this range of risk. We determine that a 100 basis point deadband on ROE should be applied to costs eligible for deferral. Consistent with our pledge in Order No. 06-532, we further find that the ROE deadband should be adjusted from 100 to 80 basis points to account for the SB 408 effect on costs incurred on or after January 1, 2006, for the Boardman Outage.

We also agree with Staff and intervenors that a utility should be given appropriate incentives to minimize costs incurred during any event that may be the subject of a deferral application. Consequently, after the 80 basis points deadband on ROE is applied,

[19] The size of the deadband reflects adjustment for SB 408 effects.

PGE should be allowed to defer 90 percent of the deadband-adjusted replacement costs eligible for deferral. Requiring a utility to absorb 10 percent of the deadband-adjusted replacement costs provides an incentive to the utility to minimize the duration of, and costs associated with, future plant outages.

ORDER

IT IS ORDERED THAT:

1. Portland General Electric Company's request to defer costs associated with the outage of its Boardman plant, from November 18, 2006 to February 5, 2006, pursuant to ORS 757.259(2)(e), is granted.

2. Pursuant to the terms of this Order, we authorize Portland General Electric Company to defer $ 26.439 million.

3. Ratemaking treatment to amortize these costs is deferred for a ratemaking proceeding.

Made, entered, and effective FEB 12 2007.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

757.259 Amounts includable in rate schedule; deferral; limit in effect on rates by amortization. (1) In addition to powers otherwise vested in the Public Utility Commission, and subject to the limitations contained in this section, under amortization schedules set by the commission, a rate or rate schedule:

(a) May reflect:

(A) Amounts lawfully imposed retroactively by order of another governmental agency; or

(B) Amounts deferred under subsection (2) of this section.

(b) Shall reflect amounts deferred under subsection (3) of this section if the public utility so requests.

(2) Upon application of a utility or ratepayer or upon the commission's own motion and after public notice, opportunity for comment and a hearing if any party requests a hearing, the commission by order may authorize deferral of the following amounts for later incorporation in rates:

(a) Amounts incurred by a utility resulting from changes in the wholesale price of natural gas or electricity approved by the Federal Energy Regulatory Commission;

(b) Balances resulting from the administration of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980;

(c) Direct or indirect costs arising from any purchase made by a public utility from the Bonneville Power Administration pursuant to ORS 757.663, provided that such costs shall be recovered only from residential and small-farm retail electricity consumers;

(d) Amounts accruing under a plan for the protection of short-term earnings under ORS 757.262 (2); or

(e) 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.

(3) Upon request of the public utility, the commission by order shall allow deferral of amounts provided as financial assistance under an agreement entered into under ORS 757.072 for later incorporation in rates.

(4) The commission may authorize deferrals under subsection (2) of this section beginning with the date of application, together with interest established by the commission. A deferral may be authorized for a period not to exceed 12 months beginning on or after the date of application. However, amounts deferred under subsection (2)(c) and (d) or (3) of this section are not subject to subsection (5), (6), (7), (8) or (10) of this section, but are subject to such limitations and requirements that the commission may prescribe and that are consistent with the provisions of this section.

(5) Unless subject to an automatic adjustment clause under ORS 757.210 (1), amounts described in this section shall be allowed in rates only to the extent authorized by the commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. The commission may require that amortization of deferred amounts be subject to refund. The commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the commission that the amount was prudently incurred by the utility.

(6) Except as provided in subsections (7), (8) and (10) of this section, the overall

average rate impact of the amortizations authorized under this section in any one year may not exceed three percent of the utility's gross revenues for the preceding calendar year.

(7) The commission may allow an overall average rate impact greater than that specified in subsection (6) of this section for natural gas commodity and pipeline transportation costs incurred by a natural gas utility if the commission finds that allowing a higher amortization rate is reasonable under the circumstances.

(8) The commission may authorize amortizations for an electric utility under this section with an overall average rate impact not to exceed six percent of the electric utility's gross revenues for the preceding calendar year. If the commission allows an overall average rate impact greater than that specified in subsection (6) of this section, the commission shall estimate the electric utility's cost of capital for the deferral period and may also consider estimated changes in the electric utility's costs and revenues during the deferral period for the purpose of reviewing the earnings of the electric utility under the provisions of subsection (5) of this section.

(9) The commission may impose requirements similar to those described in subsection (8) of this section for the amortization of other deferrals under this section, but may not impose such requirements for deferrals under subsection (2)(c) or (d) or (3) of this section.

(10) The commission may authorize amortization of a deferred amount for an electric utility under this section with an overall average rate impact greater than that allowed by subsections (6) and (8) of this section if:

(a) The deferral was directly related to extraordinary power supply expenses incurred during 2001;

(b) The amount to be deferred was greater than 40 percent of the revenue received by the electric utility in 2001 from Oregon customers; and

(c) The commission determines that the higher rate impact is reasonable under the circumstances.

(11) If the commission authorizes amortization of a deferred amount under subsection (10) of this section, an electric utility customer that uses more than one average megawatt of electricity at any site in the immediately preceding calendar year may prepay the customer's share of the deferred amount. The commission shall adopt rules governing the manner in which:

(a) The customer's share of the deferred amount is calculated; and

(b) The customer's rates are to be adjusted to reflect the prepayment of the deferred amount.

(12) The provisions of this section do not apply to a telecommunications utility. [1987 c.563 §2; 1989 c.18 §1; 1989 c.956 §1; 1993 c.175 §1; 1999 c.865 §31; 2001 c.733 §3; 2003 c.132 §1; 2003 c.234 §3]

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
BOARDMAN EARNINGS TEST
Oct 1, 2005 - Sept 30, 2006
(Thousands of Dollars)

Regulatory adjustments based on Docket UE-115, Order 01-777.	Actual Financial Statements	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	Boardman Deferral	Regulated Adjusted Results with Boardman
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,330,776	0	1,330,776	0	1,330,776	0	1,330,776
Sales for Resale	143,436	(143,436)	0	0	0	0	0
Other Operating Revenues	16,820	(5,016)	11,804	(4,863)	6,940	26,439	33,379
Total Operating Revenues	1,491,031	(148,452)	1,342,579	(4,863)	1,337,716	26,439	1,364,155
Operation & Maintenance							
Net Variable Power Cost	804,821	(177,261)	627,560	(13,855)	613,705	0	613,705
Total Fixed O&M	139,754	0	139,754	0	139,754	0	139,754
Other O&M	160,555	3,462	164,017	(10,412)	153,605	0	153,605
Total Operation & Maintenance	1,105,129	(173,799)	931,330	(24,266)	907,064	0	907,064
Depreciation & Amortization	222,740	0	222,740	0	222,740	0	222,740
Other Taxes / Franchise Fee	74,604	0	74,604	(157)	74,447	0	74,447
Income Taxes	15,912	16,897	32,809	7,703	40,512	10,392	50,904
Total Oper. Expenses & Taxes	1,418,385	(156,901)	1,261,484	(16,720)	1,244,764	10,392	1,255,156
Utility Operating Income	72,646	8,449	81,095	11,857	92,952	16,047	108,999
Rate of Return	4.00%		4.47%		5.13%		6.01%
Return on Equity	1.56%		2.39%		3.55%		5.14%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	4,073,413	0	4,073,413	(300)	4,073,114	0	4,073,114
Accumulated Depreciation	2,212,322	0	2,212,322	0	2,212,322	0	2,212,322
Accumulated Def. Income Taxes	138,606	0	138,606	49	138,655	0	138,655
Accumulated Def. Inv. Tax Credit	9,199	0	9,199	0	9,199	0	9,199
Net Utility Plant	1,713,287	0	1,713,287	(349)	1,712,938	0	1,712,938
Net Trojan Investment	0	0	0	0	0	0	0
Weatherization Investment	5	0	5	0	5	0	5
Deferred Programs & Investment	3,084	0	3,084	182	3,266	0	3,266
Operating Materials & Fuel	56,268	0	56,268	0	56,268	0	56,268
Misc. Deferred Credits	(13,912)	0	(13,912)	0	(13,912)	0	(13,912)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	55,274	(377)	54,898	(746)	54,152	463	54,615
Total Average Rate Base	1,814,006	(377)	1,813,629	(913)	1,812,716	463	1,813,180

Boardman Excess Power Costs

Excess Costs	Start Date	End Date	Initial Filing Full Capacity Dollars	Revised Figures Full Capacity Dollars	 De-rated Capacity Dollars
Nov 17 - Nov 30	11/18/2005	11/30/2005	$ 7,115,190	$ 6,987,053	$ 6,531,173
December	12/1/2005	12/31/2005	$ 19,768,532	$ 19,367,268	$ 17,988,091
January	1/1/2006	1/31/2006	$ 20,743,313	$ 20,355,062	$ 19,151,409
Feb 1 - Feb 5	2/1/2006	2/5/2006	$ 2,520,441	$ 2,473,242	$ 2,372,888
Total Excess Power Costs - Deferral Period			$ 50,147,477	$ 49,182,626	$ 46,043,561
Avoided Maintenance Savings					
Apr 29 - May 27	4/29/2006	5/27/2006	$ 4,763,722	$ 3,468,019	$ 3,253,550
Net Excess Power Costs - Deferral Period			$ 45,383,755	**$ 45,714,606**	$ 42,790,012

Commission Calculation	$ Millions
Power Costs	42.800
1 basis Point=.167798	
80 Basis Point deduction	(13.424)
90% Recovery	26.439
Authorized Deferral	26.439

D17145 - BOARDMAN POWER COST DEFERRAL

UM 1234 - APPROVED WITH OPUC ORDER NO. 07-049 DATED 02/12/2007

Month		Accrual N11147	Amortization	Interest on Avg Balance X78201	Ending Balance D17145
December	2005				0.00
January	2006	26,439,000		200,121.20	26,639,121.20
February				201,635.95	26,840,757.15
March				203,162.16	27,043,919.31
April				204,699.93	27,248,619.24
May				206,249.34	27,454,868.58
June				207,810.48	27,662,679.06
July				209,383.43	27,872,062.49
August				210,968.29	28,083,030.78
September				212,565.14	28,295,595.92
October				214,174.08	28,509,770.00
November				215,795.20	28,725,565.20
December				217,428.59	28,942,993.79
January	2007			209,893.62	29,152,887.41
February				201,397.86	29,354,285.27
March				202,789.19	29,557,074.46
April				204,190.12	29,761,264.58
May				205,600.74	29,966,865.32
June				207,021.09	30,173,886.41
July				208,451.27	30,382,337.68
August				209,891.32	30,592,229.00
September				211,341.32	30,803,570.32
October				212,801.33	31,016,371.65
November				214,271.43	31,230,643.08
December				215,751.69	31,446,394.77
	Totals	26,439,000	-	5,007,394.77	31,446,394.77
	2006	26,439,000	-	2,503,993.79	28,942,993.79
	2007	-	-	2,503,400.98	2,503,400.98
	Totals	26,439,000	-	5,007,394.77	31,446,394.77

Interest = [Prior Month Balance + (Current Month Accrual/2) + (Current Month Amortization/2)] x 9.083%/12 months beginning in October 2001
Interest = [Prior Month Balance + (Current Month Accrual/2) + (Current Month Amortization/2)] x 8.290%/12 months beginning in January 2007

Approved Cost of Capital (UE-115)	**0.0908**
Approved Cost of Capital (UE-180)	**0.0829**

Note: Interest is accrued retrospectively beginning January 1, 2006

Boardman Deferral Offsets
Values as of December 31, 2007

Boardman Deferral	31,446,395
Offsets:	
Trojan NDT refund per OPUC Order #07-015	(20,000,000)
ISFSI credits	(11,580,070)
Deferral Residual Balances	
Tariff 127-2002 PCA	(1,623,878)
Williams Settlement	(34,806)
Category A Advertising Deferral Year 1	(1,601)
SAVE	(129,243)
DSM	(74,306)
FAS 109	(19,882)
Accumulated Provisions - Special Contracts	(13,896)
Category A Advertising Deferral Year 2	165,010
Category A Advertising Deferral Year 3	153,266
Pelton / Round Butte Transition Costs	438,831
FERC Settlement	16,751
Other Deferrals	
GRID West Regulatory Asset	1,445,542
Incremental Interest on Portland Energy Solutions Note	(188,114)
Total Offsets/Residuals/Other Deferrals	(31,446,395)
Net Rate Impact	0

UE ___ / PGE / 206
Tooman - Hager / 1

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **TESTIMONY OF PORTLAND GENERAL ELECTRIC COMPANY (PGE/100-106 and PGE/200-206 non confidential portions) AND MOTION FOR APPROVAL OF PROTECTIVE ORDER**, to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. UM 1234

Dated at Portland, Oregon, this 9th day of October 2007.

RANDY DAHLGREN

SERVICE LIST

OPUC DOCKET # UM 1234

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