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July 17, 2006

***Via Electronic Filing and U.S. Mail***

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

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

Attention Filing Center:

Enclosed for filing in the above-captioned docket are the original and five copies of the Rebuttal Testimony of Pamela G. Lesh and Jay Tinker together with supporting exhibits (Exhibit PGE/400 through PGE/405) on behalf of Portland General Electric.

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

Thank you in advance for your assistance.

Sincerely,

JJD:mmd
Enclosures
cc: UM 1234 Service List

## CERTIFICATE OF SERVICE

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

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Dated this 17th day of July, 2006.

J. Jeffrey Dudley

## I. Introduction

**Q. Please state your name and position.**

A. My name is Pamela G. Lesh. I am PGE's Vice President, Rates and Regulatory Affairs and Strategic Planning. My qualifications were previously provided in PGE Exhibit 100.

My name is Jay Tinker. I am a project manager in the Regulatory Affairs department. My qualifications were previously provided in PGE Exhibit 300.

**Q. What is the purpose of your rebuttal testimony?**

A. Our rebuttal testimony responds to the reply testimony of the OPUC Staff, ICNU, and CUB in UM 1234. Specifically, we address these parties' issues regarding whether:

1) A relationship exists between the Commission's decision in this docket and projections for Boardman's availability in forecasting PGE's net variable power costs (NVPC). (Staff Exhibit 100, pgs. 21-22) (ICNU Exhibit 100, pg. 7)
2) The Boardman outage is a stochastic or scenario event, for the purpose of applying the Commission's guidance on approving deferrals as provided in docket UM 1147. (Staff Exhibit 100, pg. 16) (ICNU Exhibit 100, pg. 14)
3) The Commission's decision to approve deferral must or should impose a sharing formula, in addition to specifying the method for calculating deferred amounts. (Staff Exhibit 100, pg. 19) (ICNU Exhibit 100, pg. 4) (CUB Exhibit 100, pg. 9)
4) The Commission must consider the effects of SB 408 in applying any prior decisions regarding appropriate sharing of deferred amounts. (CUB Exhibit 100, pg. 2)
5) PGE should have engaged in actions in advance of the Boardman outage to mitigate its impact on PGE and our customers. (ICNU Exhibit 100, pg. 15)

6) PGE's application meets the requirements of ORS 757.259. (ICNU Exhibit 100, pg. 4)

**Q. In general, what do the parties recommend with respect to Commission action on PGE's deferral request?**

A. Staff and CUB both recommend that the Commission grant the deferral but, because of the sharing formula they apply to this deferral stage, PGE would have the opportunity to recover only between .74% and 5.46%[1] of the $45.7 million we incurred providing power to our customers, should we demonstrate such amounts were prudent during the amortization phase of this case (ICNU Exhibit 100, pg. 18) (Staff Exhibit 100, pg. 20) (CUB Exhibit 100, pgs. 9-10). Staff further recommends that, for the days covered by the deferral period, PGE must forecast Boardman's availability (using the longstanding four-year weighted rolling average methodology) as if the outage never occurred and Boardman was 100% available on all days (Staff Exhibit 100, pgs. 21-22). CUB does not take a position on forecasting. ICNU recommends that the Commission deny the deferral outright and is non-committal on how PGE should forecast Boardman's availability for NVPC (ICNU Exhibit 100, pgs. 4 and 7).

In essence, the parties recommend that PGE receive <u>no</u> compensation for meeting our customers' power needs during Boardman's outage, now or in the future.

**Q. Please summarize PGE's application in this case.**

A. On November 18, 2005, 23 days after we took Boardman out of service because of serious vibration issues that had arisen in the low pressure turbine, PGE applied to defer – pursuant

[1] Recovery at 5.46% may not represent parties' latest position. The figure is based on CUB's testimony which took no position on recovery of Boardman's full versus de-rated capacity. Subsequent to filing of their testimony, an article on CUB's website suggested, "a fair amount would fall well under $1 million." Using Staff's suggested recovery ($905,000) with CUB's sharing percentage (70%) PGE would recover 1.4% of its replacement power costs.

to ORS 757.259 – the costs we were incurring to replace the output of this low variable cost resource with much higher-priced market power. We believe our deferral application both minimized the frequency of rate changes (ORS 757.259 (2)(e)) and appropriately matched costs and benefits (ORS 757.259 (2)(e)). PGE Exhibit 300 estimated these excess costs at $45.4 million for the deferral period, based on a specific identification of purchased power to replace 100% of the base-load energy normally provided by Boardman. We stated that we would exclude the portion of the outage for which we received recovery under the deferral from the historical four-year rolling weighted average for determining plant availability in NVPC forecasts, to prevent any "double recovery" of the excess costs. In essence, we proposed to treat the plant as 100% available during the deferral period, matching the 100% plant output we replaced with market purchases.

**Q. Do you agree with the corrections Staff offered in response testimony regarding PGE's deferral cost calculation?**

A. We agree with all of Staff's corrections except one. The following changes are appropriate:

- Removal of line losses for both Boardman and replacement purchases
- Minimal changes for daily energy allocation in November
- Removal of a single December daily purchase
- Update of May market prices for forgone planned outage.

Applying these corrections slightly changes our estimate of the replacement costs from $45.4 million to $45.7 million. This again assumes the full output of the Boardman plant, along with a future forced outage rate calculation assumption that Boardman was 100% available for all days of the deferral.

We do not agree with Staff's proposal to calculate replacement costs based on a Boardman availability of 93.5% because this does not match Staff's proposal to treat the plant as 100% available in future forecasts that use this period in the four-year weighted rolling average. We could support using either 100% or 93.5% for both purposes; what is important is that the calculations be consistent. If the Commission used 93.5% availability for both purposes, the deferred replacement costs would be $42.8 million.

**Q. Did PGE know that the 2006 water year would produce "good" hydro-electric production when you filed the deferral application?**

A. No. As noted above, we filed this application on November 18, 2005, early in the August-July water year. Although CUB suggests (CUB Exhibit 100, pg. 6) that we may have chosen the replacement cost methodology for the deferral, rather than a comprehensive comparison of forecast to actual NVPC, based on anticipation of good hydro, we had no way of knowing in November what the 2005-2006 winter, or water year would be.

**Q. Do you agree with CUB's suggestion that hydro was above average during the deferral period?**

A. No. While PGE is pleased to finally experience near average hydro flows after six years of below normal hydro, we would not consider the November through February deferral period one of "good hydro" as CUB contends. Over the entire four-month period, PGE hydro resources produced approximately 17,000 MWh (about 1%) more than expected in the relevant RVM filings. This additional output is very small, yielding basically normal hydro. Interestingly, ICNU claims that 2005 was a bad hydro year (ICNU Exhibit 100, pg. 11). Ultimately, the type of hydro conditions experienced was not a determinant of our decision to file this deferral.

## II. The Treatment of this Deferral Application is Inextricably Related to the Method Used to Determine Boardman's Availability for Future NVPC Forecasts

**Q. Please review how PGE presently determines thermal plant availability for purposes of NVPC forecasting.**

A. As we mentioned above, and have covered extensively in testimony in other dockets (see, e.g., UE 180 PGE Exhibit 400, pgs. 19-21), the Commission has for many years used a rolling, four-year weighted average of actual forced outage rates to determine thermal plant availability for purposes of NVPC forecasts. This methodology dates back to the 1980s. This methodology not only serves as an objective means to forecast what is otherwise an unknown number, but also acts as a risk allocation mechanism. Thermal plant operations better than expected benefit customers through future NVPC forecasts that are lower than they would otherwise have been because of greater expected output from low variable cost thermal resources. All else being equal, the utility is likely to spend more on NVPC in those years than the forecast because of the forced outage rate assumption. Likewise, thermal plant operations worse than expected compensate utilities in future NVPC forecasts that are higher than they would otherwise have been because of lower expected output from low variable cost resources. All else being equal, the utility is likely to spend less than the NVPC forecast in those years.

For example, Boardman performed extraordinarily well in both 1998 and 2001 with Equivalent Forced Outage Rates (EFOR) of 2.58% and 2.89% respectively. Both performances were included in the rolling average. The 2.89% was included in the 2006 RVM as an input for the current 6.5% Boardman forced outage rate or 93.5% availability factor. The annual Boardman EFORs comprising the current outage rate are below in Table 1.

**Table 1 2006 RVM Annual EFOR**

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

**Q. Based on that explanation, how does a deferral application for a thermal plant outage affect NVPC forecasting?**

A. Because the rolling, four-year average methodology uses historical information, deferral recovery for a period of thermal plant forced outage could result in a "double recovery" for the utility, as the forced outage days depress the availability factor for the subsequent years. Because of timing of data availability, the effect actually occurs during years two through six after the outage. Thus, for Boardman, the 2005 outage days would affect NVPC forecasts in 2007 through 2010; the 2006 forced outage days would affect NVPC forecasts in 2008 through 2011.

**Q. Did PGE consider, in November 2005 as this outage unfolded, simply relying on this methodology to "recover" the replacement costs it was incurring?**

A. Yes. For the reasons explained in our opening testimony, we saw that the use of the four-year average methodology as less desirable than a deferral (PGE Exhibit 100, pgs. 5-6). Foremost of those reasons was the sizable effect of this outage on NVPC forecasts during the years that it is part of the four-year average. All else being equal, including an outage of this duration in the forecasting methodology increases the chances that customers' rates do not actually reflect cost of service for the period. It also means that customers end up paying something more or less than the replacement cost, rather than the actual cost. We also noted that relying on the outage forecasting methodology to handle risk allocation of these kinds of costs could cause prolonged periods of mismatch between rates and cost of service if the utility involved did not have a regular schedule to forecast NVPC, as PGE does with the RVM and proposes to continue in UE 180.

In addition, at that time, we did not and could not know how the outage would unfold, particularly its duration. Because of the constraints of the deferred accounting statute, PGE had to file an application to preserve that regulatory treatment as an option. This decision should not result in a "head's we win, tails you lose" or "no recovery" situation that both alternatives produce.

**Q. Given that you now know the duration of the outage, would PGE consider continued use of the rolling, four-year average methodology of determining plant availability for Boardman a reasonable alternative to Commission approval of this deferral application?**

A. Yes, with a caveat. Because the forced outage spans two calendar years, the effect this number of days would otherwise have on the forecasted availability is muted from what it would be had an outage of this length occurred in a single calendar year. Assuming Boardman availability at 93.5% over the next six years for illustration purposes, Table 2 below shows the availability factors that would result from this treatment.

**Table 2**
**Boardman Availability Factor**

| Year | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|
| Availability Factor | 90.7 | 88.4 | 88.4 | 88.4 | 91.3 | 93.5 |

If the disconnect between our prices and cost of service that this difference will cause is acceptable, we are willing to use this option. The caveat is the one we explained in our testimony in docket UE 180 in connection with our proposed Variance Tariff. The risk allocation feature of the traditional forced outage methodology works only if all years reflected in a particular forecast are under the same regulatory framework; i.e., all with the same adjustment for the difference between actual and forecast, whether that be none, all, or some percentage. If the Commission were to deny this deferral in preference for using the traditional risk allocation for thermal plant forced outages of the four-year average methodology, and also to adopt our proposed Variance Tariff, we would need to adjust credits or charges to customers under that tariff to effectuate the Commission's decisions. As explained in UE 180, we prepared the tariff to accommodate this eventuality.

**Q. Is it clear that the parties believe the deferral and inclusion of this forced outage in future years' NVPC forecasts are equally viable alternatives?**

A. No. Staff's position appears to be that PGE should receive virtually no recovery of the actual replacement power costs incurred to serve customers under the deferral because losses of this sort are "in the normal course of business" and, then, to effectuate this result, preclude use of the risk allocation features of the forced outage rate methodology by assuming Boardman was 100% available during the deferral period. In other words, by requesting deferral, it appears Staff believes PGE has foregone the opportunity to use the other risk allocation methodology.

During deposition, Staff essentially revised its historical position on applying the four-year forced outage calculation. It appears Staff would now limit inclusion of events to those that are expected to occur once every four years.

> …the four-year average calculation implicitly assumes that, that the type of event would occur once in every four years. (PGE Exhibit 404, pg. 14)
>
> I mean, the purpose of normalizing forced outages in setting base rates is to reflect a normal level of forced outages on a going-forward basis. What I'm suggesting is that the four-year average calculation may not be the best way of doing it. It's the way that we've traditionally done it and it's the way that PGE has done it in recent cases.
>
> What I'm suggesting is that this deferral application illustrates the weaknesses in that approach. The weakness in that approach is that you can't include -- that it -- one, it doesn't include -- it includes an assumption that whatever goes into that four-year average calculation is going to occur on a going-forward basis at a probability of one in every four years. And

> what I'm suggesting is that that may not be appropriate. (PGE Exhibit 404, pg. 15)

CUB classifies this outage as abnormal and extraordinary and, accordingly, takes the position that the forced outage rate methodology should exclude it, but also recommends virtually no recovery because the loss is within the range of what CUB believes utilities should normally bear. As noted above, ICNU questions whether it would be appropriate to include this outage in the traditional forecasting methodology.

**Q. Were the alternatives of deferral or use of the forced outage rate methodology available for PacifiCorp's Hunter plant outage that is the basis of the parties' recovery recommendations in this proceeding?**

A. Not easily. At the time of the Hunter outage, PacifiCorp had already requested a comprehensive deferral of the difference between actual and forecasted NVPC because of the Western power market crisis and drought conditions. Handling Hunter under the traditional risk allocation of the forced outage rate methodology would have required making outboard adjustments to the comparison of actual and forecast NVPC.

## III. The Boardman Outage is a Scenario Event that Qualifies for Deferral with Material Financial Impact.

**Q. Why is classification of Boardman's outage as a scenario or stochastic event important?**

A. The Commission's guidance on deferred accounting in Docket UM 1147 uses this distinction to identify the size of financial effect required for approval of deferred accounting. The chart below from Staff's testimony (Staff Exhibit 100, pg. 15) shows the relationships between classification and deferral approval outcome.

| **Financial Effect** | **Type of Event** | | |
|---|---|---|---|
| | Stochastic Risk | Scenario Risk | Commission Approved |
| | (1)(2) | (3)(4) | (5)(6) |
| Substantial | Deferral Considered (7) | Deferral Considered | Deferral Considered |
| Material | Deferral Not Considered | Deferral Considered | Deferral Considered |
| Immaterial | Deferral Not Considered | Deferral Not Considered | Deferral Considered |

(1) Stochastic risk is defined as a risk that can be predicted as part of the normal course of events; it is quantifiable and can be represented by a known statistical distribution (Order 04-108).
(2) Examples of stochastic risk are hydro variability, normal plant outages, employee compensation, and weather.
(3) Scenario risk is defined as a risk that is not susceptible to prediction and quantification; it is often represented by abrupt changes in business factors or practices (Order 04-108).
(4) Examples of scenario risk are catastrophic plant outages (Trojan), environmental costs, and material unexpected changes to costs.
(5) These events are either mandated, pursuant to Commission approval, or emerging from a rate case settlement.
(6) Examples of these events are DSM costs, a PGA, and intervenor funding.
(7) Event should be extraordinary.

**Q. Why do you consider the Boardman outage to be properly classified as a scenario risk?**

A. PGE considers this outage, which Staff determined to have a likelihood of occurring approximately once every hundred years (Staff Exhibit 100, pg. 16), much closer in nature to the Trojan outages of the early 1990s than to the variation in water years. It is a scenario event that should qualify for deferral upon a showing of material financial effect.

**Q. What positions do the parties take?**

A. Staff and ICNU assert that the outage is a stochastic risk.

CUB does not characterize the outage (CUB Exhibit 100, pg. 3). CUB's testimony does, however, state that the outage is "extraordinary" (CUB Exhibit 100, pg. 1) and refers to it as a "catastrophic outage" (CUB Exhibit 100, pg. 4). Similar to Staff and ICNU, CUB believes it inappropriate to include the outage in the four-year forced outage rate, "as an outage of this magnitude is unlikely to repeat itself" (CUB Exhibit 100, pg. 4). This implies that CUB might consider the outage a scenario event.

**Q. Are the Staff and ICNU positions that this outage is stochastic well supported?**

A. No. During deposition, Staff characterized the outage as "Rare. Not normal." (PGE Exhibit 404, pg. 3) and "it is not normal in the sense that it was an extreme -- it had an extreme duration associated with it" (PGE Exhibit 404, pg. 2). Staff concludes that "an outage with duration greater than 104 days occurs roughly once every 100 years" (Staff Exhibit 100, pg. 16). Using Staff's Table 3, these terms seem closer to the Trojan category than the "normal" plant outages indicated as "stochastic."

The ICNU witness does not disagree that the outage was a rare occurrence and uses this characteristic to question the appropriateness of including such a long outage in the four-year average forced outage rate noting "there is also the question of whether it was an event that is likely to re-occur in the future" (ICNU Exhibit 100, pg. 7). This position appears inconsistent with ICNU's position that the outage was a stochastic event.

**Q. Does Staff offer concrete guidance on the difference between outages which are stochastic versus those that are scenario risks?**

A. No, the following exchange is illustrative of Staff's guidance:

> Q. Page 16 of your Testimony. I'm sorry, I don't have a line. 4. It says, "Staff considers generating plant forced outages to be a stochastic risk." Right?
>
> Is that all generating plant outages?

> A. Staff considers generating plant outages that occur during the normal course of business to be a stochastic risk.
> Q. Okay. So the question was whether that means all plant outages are a stochastic risk.
> A. No, not all plant outages are a stochastic risk.
> Q. Okay. Which ones aren't?
> A. Those that do not occur during the normal course of business. (PGE Exhibit 404, pgs. 12-13)

**Q. Did Staff define "normal course of business"?**

A. Yes. Under questioning it was defined as an event that occurs "On the order of once every hundred years." (PGE Exhibit 404, pg. 4)

**Q. What is troubling about this definition?**

A. Utilities do not plan for events that occur once every one hundred years. IRPs are not based on 1-in 100-peak demands, hydro availability is not based on 1-in-100 water years. Staff's definition seems designed specifically to classify the Boardman outage as a stochastic risk, not a scenario risk. One can see the fallacy in the definition by simply examining the lifetime of an asset such as Boardman. When built, Boardman's assumed useful life was 40 years. It is unclear how an event occurring once in every 2 ½ lifetimes is "normal".

**Q. Does Staff's conclusion that the Boardman outage is a stochastic risk fail on other criteria that Staff has used to distinguish the categories or scenario and stochastic risk?**

A. Yes. Staff has explained that variations from stochastic risks should balance over time while variations from scenario risks will not (Order 04-108, pg. 9).

> Let me try and answer that by stating the question. I think the question here is should there be a high likelihood that the swings of a stochastic risk will balance out over time through rate making. Should there be a high -- should there be a – should we do rate making, should we design our rates in such a way, that there is a high likelihood that for stochastic risks the swings will balance out over time.
>
> I would answer yes, we should. (PGE Exhibit 404, pg. 10)

Assuming continued use in Oregon of the traditional forced outage rate forecasting methodology (and exclusion of this outage from the methodology as parties have suggested), there is little to no possibility the loss from the Boardman outage will balance out over time. There are no 'negative' forced outage rates. The four-year forced outage rate incorporates superior performance from any single year. Any company benefits from this superior performance are short lived, accruing during the year, and passed to customers in the four following years. Superior plant performance is included in the four year average through the EFOR. As we indicated earlier, EFORs of less than 3% for Boardman have been reflected in rates through the four-year average.

Even if Oregon adopted an entirely different methodology for determining availability of thermal plants to forecast NVPC, it is still unlikely that a forced outage of this duration would "balance out over time," simply because a thermal plant cannot be more than 100% available. Thermal plants differ significantly from hydro generation in this regard: thermal plants cannot produce more than 100% of "average," which hydro can, depending on water conditions.

**Q. Does Staff suggest how such swings could balance over time?**

A. Staff states there are many methods that the Commission could use to achieve balance over the years:

> But there's many methods available to the Commission to achieve that balance over time. I just wanted to state that. They could use deferred accounting, they could use normalized rate making. There's many methods that the Commission could use to achieve that balance over time.

Using Staff's recommendations, however, PGE will recover less than 1% through deferral, and may never include this outage period in the rolling four-year average. Staff makes no mention of other options.

**Q. Has Staff analyzed the balancing of these swings over time?**

A. No. The Staff witness stated that he had not analyzed how an outage of this duration might balance out over time such that it fit within the definition of a stochastic risk:

> I haven't, in this testimony, done any analysis of the balance over time. (PGE Exhibit 404, pg. 11)

**Q. Staff suggests events such as this outage could be modeled in forecasting NVPC for purposes of setting rates. Would this be appropriate?**

A. First, it should be clear that neither PGE's current prices nor those in effect in 2005 include the potential of this outage. There is no "forced outage adder to account for outages that are more extreme than those reflected in a normal four-year rolling average" (Staff Exhibit 100, pg. 23). As to the appropriateness of including extreme events in rates, no party has demonstrated how such an event could be reasonably modeled in rates. Such a mechanism would be problematic at best; extreme events cannot be modeled. An adder would need to include <u>all</u> potential disruptive events, such as an earthquake, or a terrorist attack to name two extreme events.

Such an adder would also violate a basic regulatory tenant - matching costs customers pay with the benefits they receive. Staff suggests an outage of this duration occurs once every one hundred years. If rates include costs related to such an extreme event, customers in year one pay for something that may not happen until year 100. The converse is true as well: customers in the future (one hundred years) would pay for current outages. While there is no requirement that costs and benefits be matched perfectly in time, Staff's construct would result in a great temporal mismatch of costs and benefits.

**Q. Has Staff demonstrated that the Boardman outage is "stochastic?"**

A. No. Staff defines a stochastic risk as a risk that can be predicted as part of the normal course of events; it is quantifiable and can be represented by a known statistical distribution (Order 04-108). However, Staff has not performed the necessary analysis to prove that the risk of all possible Boardman outages is quantifiable and can be represented by a known statistical distribution.

**Q. Why do you contend that Staff has not done this analysis?**

A. In deposition Staff witness admits that such an analysis would involve a histogram that reflects the number of occurrences of a type of an event (PGE Exhibit 404, pg. 5). Staff further admits that, "I have not created such a histogram…" (PGE Exhibit 404, pg. 5). While Staff believes it is "likely possible" to create such a histogram, they are unsure of even the data to use to construct it (PGE Exhibit 404, pg. 5). "I mean, you have to - - you have to actually do the analysis and start down the path before you're gonna know whether or not at the end of the day it's a reasonable data set to use. You'd have to actually do the analysis." (PGE Exhibit 404, pg. 6) Further, Staff agrees that statistical testing may be required to validate the model (PGE Exhibit 404, pg. 7). Staff has done no such analysis and has run no statistical tests.

**Q. Does the classification of this outage as stochastic or scenario matter, ultimately, to the parties' recommendations whether the Commission should approve deferral?**

A. No, not really. Staff finds the financial effect substantial and thus eligible for deferral. CUB also recommends approving the deferral, albeit without characterization.

## IV. The Commission's Decision to Grant this Deferral Need Not and Should Not Impose a Sharing Mechanism.

**Q. Did PGE's application for the deferral propose a sharing mechanism in addition to the method of calculating the amount to defer?**

A. No.

**Q. Why not?**

A. Based on our experience with deferrals and our understanding of the deferral statute, we believe that there is no requirement that authorizing a deferral include a sharing methodology and that, in this instance, the earnings test is the best means to ensure that any amount authorized for amortization is reasonable.

We conclude that the statute does not require sharing because many deferrals the Commission authorizes include no sharing and good policy reasons support no sharing. For example, the deferral of PGE's anticipated 2005 Oregon State income tax kicker, the ISFSI pollution control tax credits, Information Technology costs, Intervenor Funding, and Advertising costs all required no sharing. Certainly, the statute does not say anything about limiting the deferral of costs or revenues to some amount produced by sharing. We can recollect no instances in which the deferral of a revenue increase or cost reduction included any sharing. The only instances, in our recollection, of the deferral of a cost increase or revenue decrease that included sharing are those that relate to power costs. Proper regulatory policy would treat all deferrals the same.

We conclude that the earnings test is the best means to assure that the amount of replacement costs PGE recovers from customers is reasonable for several reasons. This tool, provided for in the deferred accounting statute, has historically served to:

(a) ensure that cost savings or revenue increases outside of the deferred items did not offset their effect such that recovery or refund of the deferral produced an unreasonable return for the utility;

(b) express the Commission's discretion regarding how to share discrete cost or revenue changes between customers and the utility.

The most complete Commission discussion on its use of the earnings test was in Order No. 93-257.

> In the future, the Commission intends to tailor earnings tests to fit the type of deferral. For example, if the Commission authorized deferral of an emergency increase in cost, the earnings test applied might allow a utility to amortize the deferral to the extent that it brings the utility's earnings for the period up to the bottom of a reasonable range. This type of earnings test could also apply to gas tracking cases. In this way, the Commission could encourage the utility to control its costs. (pgs. 11-12)

In PGE's experience, inclusion of a sharing component in the calculation of the deferral itself has occurred when one or both of the following circumstances are present:

1) a need exists to align the short-term interest of the utility with that of customers because utility decisions yet to be made will affect the size of the deferral. For example, when the Commission granted PGE 90% recovery of the costs it projected to incur to replace Trojan when it went off-line in 1991, the Commission approved the deferral early in the replacement period using a formula that compared actual to forecasted NVPC. Under this calculation methodology, PGE's purchasing decisions yet to come would affect the amount of the deferral and sharing the total aligned interests.

2) an expectation exists that the earnings test will limit the amount deferred. This situation occurred during the Trojan deferrals that followed its permanent closure

(UM 594 and UM 692). The replacement power cost percentages chosen reflected the expected reduction in O&M costs that accompanied plant closure.

**Q. How does your experience reconcile with the Commission's decision in UM 995, which the parties cite extensively as the basis for recommending that the Commission impose a sharing formula at the deferral stage?**

A. We can only speculate regarding the circumstances that produced the UM 995 decision because it was not a generic docket and PGE did not participate in the decision. The decision concerned a specific set of circumstances for one utility and one time period. We do know that a number of circumstances are different here:

1) The UM 995 deferral period was for almost 12 months; our deferral request is not quite three months.

2) The UM 995 deferral tracked the variance between forecast NVPC and actual NVPC; ours tracks only specifically incurred Boardman replacement power costs.

3) The Commission had not determined a forecast of NVPC for purposes of PacifiCorp's rates at the time of UM 995. The Commission last set PacifiCorp's NVPC forecast for rate setting purposes in UE 111 (filed in 1999). The UE 111 test period did not align with the UM 995 deferral period. By contrast, the Commission set the PGE NVPC forecast for purposes of the period covered by this deferral application in late 2004 and late 2005, respectively, for the portions of the deferral in 2005 and 2006.

We do know that for the PGE deferral frequently cited as establishing a requirement of a 250 basis point deadband – the 2001 power cost adjustment – PGE agreed to the deadband only a month into the deferral period when it was still equally probable that the mechanism would produce a credit to customers as a charge. Of course, this application of a deadband was in a settlement that specifically states that the parties agreed not to cite it as precedent. We do not know if a positive outcome was possible for PacifiCorp at the time the Commission imposed the deadband in UM 995. In the instance of this Boardman deferral application, no range of outcomes is possible. A 250 basis point deadband would operate simply as a 250 basis point reduction in the amount of cost PGE incurred to serve customers that it could recover. As we explained in the previous section, little or no possibility exists that PGE would ever have an opportunity to "balance out" this loss through better-than-expected availability at Boardman.

**Q. Does the nature of the risk addressed by a deferral as stochastic or scenario matter in terms of applying a sharing formula to the authorization of the deferral?**

A. We do not know. The Commission's guidance in UM 1147 focused on the circumstances in which it would authorize a utility to defer amounts; it did not address the formulas – identification or sharing – by which utilities would calculate authorized deferrals. On deposition, Staff explained its understanding of the effect of classification on sharing requirements. For scenario risks, Staff suggested that no sharing may apply to the deferral authorization:

> Well, you know, in theory, if the -- if the type of event was a scenario event, one that was not expected to occur in the normal course of business, and it resulted in one extra dollar, then, you know, I think an argument can be made that that would be a material effect.
>
> Now whether or not we're going to go through the regulatory burden of, you know, trying to recover that one extra dollar, I mean, there's some lower threshold that just, in the normal course of regulation, doesn't rise to the level of needing to be accounted for. But what I'm saying is that the threshold for material is quite low. (PGE Exhibit 404, pgs. 8-9)

**Q. Is a deadband necessary to account for cost offsets that may mitigate the excess costs incurred under the deferral?**

A. No, this is a concern CUB expresses (CUB Exhibit 100, pg. 7). As noted above, however, the statutory earnings test serves this purpose quite well. In 1995, Order No. 95-1216, application of the earnings test to PGE's deferral of Trojan replacement power from July, 1 1993, to March 31, 1994, resulted in PGE receiving approximately 20% of the authorized deferral because O&M reductions at the plant offset the majority of the additional variable power costs. The use of a deadband to capture such effects assumes cost offsets that may not exist.

## V. The Commission Must Consider the Effects of SB 408 in Deciding this Application

**Q. Has the Commission indicated it will consider the impact of SB 408 when evaluating issues?**

A. Yes. In Order No. 06-400 the Commission indicated they would consider tax effects in evaluating issues:

> In response, we will consider the tax effects when evaluating issues in other dockets, such as power cost adjustment mechanism. (pg. 9)

**Q. Will SB 408 affect the financial impact of the Boardman outage?**

A. Yes. The replacement costs that PGE incurred during the 2006 portion of the requested deferral period will affect PGE's taxes paid for 2006, which is the first year of the income tax true-up required by SB 408. All else being equal, this would trigger a credit to customers, and thus a loss to PGE, of an additional 40% of the 2006 replacement cost PGE incurred.

**Q. Please elaborate.**

A. Given the approach to deriving "taxes collected in rates" currently supported by the Commission in the AR 499 proceeding, actual variations in the stand-alone financial performance of the utility will lead to refunds/surcharges. Thus, a requirement in a deferral docket (such as UM 1234) that a utility absorb power costs will effectively require the utility to refund to customers the tax benefit of the excess costs that the utility absorbed. As a result, a 250 basis point deadband effectively imposes additional harm onto the utility, which increases the effective size of the deadband.

**Q. Can you provide an example?**

A. Yes. For simplicity, assume that a utility has no parent, no subsidiaries, and no non-utility operations. Effectively, the utility is a stand-alone utility. During a ratecase, the

Commission authorizes rates with an expected ROE that translates into an expected tax liability of $50 million. During the year, the utility experiences financial results that perfectly mirror the rate case, except for an outage at a major plant that results in additional costs of $10 million, for which the utility has sought deferral. If the application of a deadband in the deferral proceeding required the utility to absorb the entire excess costs, then earnings will be lower by $10 million (pre-tax) relative to the rate case assumptions. Since the utility costs were higher than in the test year it will have a lower tax liability by $4 million (40% of $10 million). Under Staff's proposed rules in AR 499, the utility would refund this $4 million to customers. Thus, the application of a deadband in this example deferral docket not only required the utility to absorb $10 million of higher power costs, but effectively resulted in an additional $4 million refund through SB 408.

**Q. Was SB 408 in effect at the time of UM 995 or the deferral in which PGE stipulated to a 250 basis point deadband?**

A. No.

**Q. What is the effect of a 250 basis point deadband given SB 408?**

A. Staff has characterized this amount as "normal variability between rate cases that would not trigger a rate filing by the company or a show cause request by other parties." (Staff Exhibit 100, pg. 20) Assuming the deadband applies to an instance in which the actual result could be either costs or savings of up to 250 basis points, applying SB 408 will produce credits or charges to customers, depending whether the utility is in the positive or negative side of the deadband. Thus, a positive 250 basis points would cause a charge to customers. Using

Staff's numbers as an example, customers would pay $16.5 million[2] for this "normal variability." A negative 250 basis points would cause a credit to customers. Again, using Staff's numbers as an example, the utility would bear $16.5 million for this "normal variability." Even if UM 995 represents an inflexible Commission policy, rather than a fact-specific decision, that 250 basis points is variability that warrants no adjustment to rates (unless it is for specific Commission-approved items such as the tax kicker), the Commission must revisit that decision in light of the effects of SB 408.

**Q. Did Staff or ICNU take SB 408 into account?**

A. No. (PGE Exhibit 404, pgs. 16-17) (PGE Exhibit 405, pg. 1)

[2] Staff presents $41.9 million as a 250 basis point deadband (Staff Exhibit 100, pg. 20). Applying a 39.3% composite tax rate to this figure yields $16.5 million.

## VI. The Commission Should Ignore Claims that PGE Should Have Known this was Coming and Prepared in Advance.

**Q. ICNU claims that the Boardman outage was a foreseeable event and that PGE should have taken action in advance of the outage (ICNU Exhibit 100, pg. 14). Do you agree?**

A. No. Despite the rhetoric in this docket, these types of major outages cannot be predicted. Staff has indicated that these types of events are "1 in 100." We do not believe one can put an exact frequency on the event. However, clearly it is a very infrequent event. If PGE was to purchase power in advance of such outages, how much should we purchase? When? And who should pay for that power? It would not make sense to purchase today for an infrequent event that may not happen for years (or decades). ICNU seems to be concerned about matching costs and benefits, yet their suggested scheme, in addition to being completely unrealistic, would force costs to be incurred today for events that may not happen for significant periods of time in the future.

**Q. Are there other options aside from purchasing in advance?**

A. ICNU seems to suggest that other options exist, but proposes nothing specific. Such options do not exist. For example, there are currently no counterparties providing replacement power cost insurance.

**Q. Is there a common element between ICNU's claims that advance actions should have been taken and Staff's claim that rates can be set in such a way as to balance these events out over time?**

A. Yes. We believe parties have a fundamentally mistaken notion that regulatory constructs can be established that effectively remove any need for the Commission to take action when significant unexpected events occur. Cost of service rates set on periodic forecasts cannot handle all contingencies as utilities deliver upon their obligation to serve. Regulation's strength is its flexibility to address events as they occur. The deferred accounting statute is one tool the Commission has to do just that. The Commission's statutory task of assuring safe and adequate service at fair and reasonable rates is not limited to doing so only periodically in rate cases.

## VII. PGE's Deferral Meets ORS 757.259 Requirements.

**Q. ICNU's witness states that PGE's deferral does not minimize the frequency of rate changes because PGE would have been unlikely to obtain interim rate relief (ICNU Exhibit 100, pg. 10). Do you agree?**

A. No. However, we believe this is a position regarding the legal standards for interim rate relief and is inappropriate for inclusion in expert policy testimony. PGE will address ICNU's argument regarding interim rates in legal briefs.

**Q. ICNU testimony also asserts that PGE's deferral application fails to meet the standard of appropriate matching costs and benefits (ICNU Exhibit 100, pg. 12). Do you agree?**

A. No. ICNU has made this claim in other deferral proceedings as well, most recently in legal comments in UM 1265/1257 (Grid West deferral). The requirement of matching costs and benefits does not require exact temporal matching of costs and benefits. In fact, such a strict standard would effectively be impossible to meet since the Commission must go through a process of considering a deferral application before it approves amortization. The requirement of matching costs and benefits requires that customers pay the costs for services for which they benefit. Customers have benefited from the power provided by PGE to replace Boardman's expected output. This deferral provides a mechanism for customers to cover the costs of such power. The exchange below from the deposition of Staff witnesses Galbraith and Owings illustrate that customers have received this benefit (PGE Exhibit 404, pg. 1):

> Q. So whatever demand customers put on it, PGE has to go find the power and deliver it, right?
> A. That's correct; yes.
> Q. So that customers benefitted from this power that was used?
> A. Yes.

**Q. Does this conclude your testimony?**

A. Yes.

## List of Exhibits

| PGE Exhibit | Description |
|---|---|
| 401 | Revised Boardman Excess Cost Calculations |
| 402 | Hydro Generation in Deferral Months |
| 403 | Intervenor Suggested Recovery |
| 404 | Referenced Staff Deposition Pages |
| 405 | Referenced ICNU Deposition Page |

## Boardman Excess Power Costs

| | | | Initial Filing | Revised Figures | |
|---|---|---|---|---|---|
| | | | Full Capacity | Full Capacity | De-rated Capacity |
| Excess Costs | Start Date | End Date | Dollars | Dollars | 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 |

# Comparison of Hydro Generation (MWH) During the Boardman Deferral Period

| | November | December | January | February | Total |
|---|---|---|---|---|---|
| Forecast | 368,790 | 448,110 | 511,345 | 435,065 | 1,763,310 |
| Actual | 382,660 | 408,625 | 549,642 | 439,612 | 1,780,539 |
| | | | | | |
| Actual - Forecast | 13,870 | (39,485) | 38,297 | 4,547 | 17,229 |
| % Increase (Decrease) | 3.76 | (8.81) | 7.49 | 1.05 | 0.98 |

# Calculation of Suggested Recovery by Intervenors

PGE Actual Replacement Costs
**$ 45,700,000**

| Party | Replacement Costs | Basis Points | $/Basis Point | Shared Costs | Sharing Percent | Recovery | Percent of Replacement Costs |
|---|---|---|---|---|---|---|---|
| ICNU | $ 42,600,000 | 254 | $ 167,717 | $ 670,866 | 50% | $ 335,433 | **0.73%** |
| Staff | | | | $ 905,000 | 50% | $ 452,500 | **0.99%** |
| CUB | $ 45,700,000 | 271 | $ 168,635 | $ 3,541,328 | 70% | $ 2,478,930 | **5.42%** |

Q So whatever demand customers put on it, PGE has to go find the power and deliver it, right?

A That's correct; yes.

Q So that customers benefitted from this power that was used?

A Yes.

Q And what's your estimate of the incremental cost of the power due to the Boardman outage?

A The incremental cost of power. I'm not sure where you're going with that there.

Q You came up with a number in your testimony for what the deferral should be, right? What the cost was. Didn't you?

A Yes.

Q What was that number?

A For the deferral period, Staff estimated the replacement power cost to be $54.2 million.

Q And then you made some adjustments to that?

A That's correct. The amount that would be eligible for deferral would be that $54.2 million number minus the baseline costs that are included in PGE's rates.

Q Which are?

A $8.2 million. That results in what I've called an excess power cost of $46.1 million. And the Boardman outages is a stochastic event or a stochastic risk, so it's in the first column. And to be eligible for deferred accounting, for the Commission to exercise its discretion to authorize deferred accounting, the Commission has said that the financial effect must be substantial.

Q So it is -- the box with footnote 7 in it, is that the right box?

A That's correct.

Q Okay. So was the Boardman outage a normal plant outage?

A I don't know what you mean by normal, so you'll have to --

Q Well, that's -- okay.

Footnote 2. "Examples of stochastic risk are hydro variability, normal plant outages, employee compensation, and weather."

Was this a normal plant outage?

A It's normal in the sense that it occurs in the normal course of business. So it is not normal in the sense that it was an extreme -- it had an extreme duration associated with it.

Q Okay, so was it normal or not normal?

MS. ANDRUS: Objection; asked and answered.

occurs in the normal course of events. I would consider it to be a normal plant outage.

Q But we just established that it was not normal in duration, right?

A It is a -- it's a very long plant outage (nods head). It's a hundred-and-five-day plant outage, which is a rare plant outage duration.

Q Not -- not normal.

A Rare. Not normal. (Nods head.)

Q Okay. So if it's not normal, the other option on your chart is catastrophic, right?

A I'm not sure that there's only two categories of plant outages, normal and catastrophic. There might be -- you know, one way of looking at this is, is that it could be a normal outage that occurs in the normal course of events, but it happens to be on the long end of the duration scale.

I'm -- you know, I'm not sure that the only two categories that -- I'm not sure that every single plant outage can be put into a normal category and/or a catastrophic category, if that's what you're trying to get me to do.

Q And you don't think that can be done.

A I think it requires judgment. And, again, I've said that I believe that this Boardman plant outage is the type of plant outage that occurs in the normal course of events. It happens to be a long plant outage, and so it -- it's a rare event. But it's still an event that occurs in the normal course of business.

Q What do you mean by occurs in the normal course of business?

A It's one that can be expected to occur.

Q How often?

A Not, not very frequently.

Q Do you know how frequently?

A On the order of once every hundred years.

Q And that's the normal course of events? Once in a hundred years?

A Yes.

Q What gets included in the four-year rolling average? For plant outages.

MS. ANDRUS: Did you say "what gets"?

MR. TINGEY: Yes.

THE WITNESS: Outages that occurred in the four-year period.

BY MR. TINGEY:

Q Like this one?

A Not necessarily.

Q Okay, why not?

question?

THE WITNESS: No.

BY MR. TINGEY:

Q Okay. You used the phrase "frequency distribution." What does that mean?

A I'm thinking in terms of -- I'm thinking in terms of a histogram that reflects the number of occurrences of a type of event.

Q Do you know that? (Indiscernible) Boardman?

(Reporter inquires.)

BY MR. TINGEY:

Q Do you know of such -- could you create such a histogram? Do you have the information to do that?

A I have not created such a histogram; however, I believe that it is likely possible that one could create such a histogram using the type of data that -- that PGE got from the North American Reliability Council: the NERC GADS data. It might be possible to create such a histogram from that data center.

Q This requires some modeling of this data? Is that how you --

How do you do it?

A Well, you would get the NERC data, the NERC GADS data, and you would do analysis similar to the analysis that PGE has done in this case to look at the frequency of these types of events. And you'd want to look for units of similar fuel type and similar capacity and simply look for the number of outages of this duration over the period of time that's covered by that data set.

Q Is that a proper data set to use for this analysis?

A As I stated, you know, I believe that one could use the NERC data for this purpose. But that's my belief at this time. I mean, you have to -- you have to actually do the analysis and start down the path before you're gonna know whether or not at the end of the day it's a reasonable data set to use. You'd have to actually do the analysis.

Q Okay. So how do you know at the end of the day whether it was a reasonable data set?

A You'd want to look at how many -- how robust that data set was. You'd want to look and see how many units of similar fuel type and similar capacity are in that data set, whether or not there's differences between the units that are included in that data set and the unit that you're trying to look at, namely, Boardman. You'd want to see if there was differences in there that matter.

If there's differences that make a

difference, then it may not be an appropriate data set to use.

But if those -- but if there are no differences, if the similarities are significant enough, then it's probably a data set that could be used for that purpose.

Q Are there statistical tests you could run or that such a model should meet?

A There may be.

Q Do you know of any?

A Not sitting here today, no.

Q And all you're talking about is the duration of such an outage, not -- that wouldn't have anything to do with the financial impact; is that correct?

A The likelihood of that type of outage; that's correct.

Q Okay. So for the analysis we've just been discussing, the financial impact didn't enter into it.

A That's correct.

Q If you wanted to model the financial impact, what would you have to do?

MS. ANDRUS: Do you mean model it in conjunction with the analysis that he just discussed?

MR. TINGEY: Yeah, yeah. Same kind of deal.

Q Okay. What's the threshold for material?

A The threshold for material is pretty low. In other words, to qualify for -- let's go back to the chart for one second.

MR. TINGEY: Page 15.

THE WITNESS: So the question was is what's the threshold for material.

BY MR. TINGEY:

Q Yes.

A And so again I'm going to put it back in the context of the Commission exercising its discretion, and back in the context of this two-step, two-stage test.

If the type of event is -- is a scenario event, one that is not expected to occur in the normal course of business, and actually one of those types of events occurs, then the financial impact need not be substantial; it simply needs to be material. And so I expect the threshold for material is quite a bit less than substantial.

Q Do you know how much?

A Well, you know, in theory, if the -- if the type of event was a scenario event, one that was not expected to occur in the normal course of business, and it resulted in one extra dollar, then, you know, I think an argument can be made that that would be a material effect.

Now whether or not we're going to go through the regulatory burden of, you know, trying to recover that one extra dollar, I mean, there's some lower threshold that just, in the normal course of regulation, doesn't rise to the level of needing to be accounted for. But what I'm saying is that the threshold for material is quite low.

Q Okay. There's no benchmark out there like you found for substantial.

A That's correct.

Q Okay.

A Not that I'm aware of.

Q Okay. And with respect to "substantial," you used this 250-basis-points as the test to decide whether it was substantial and then used it for the deadband as well, correct?

A I used the 250 basis points of PGE ROE to -- as the standard for whether or not the financial impact of the Boardman outage was substantial or not, and concluded that the financial impact was substantial.

Q Then you imposed that 250 basis points as a deadband as well, right?

reading of that, do you agree with it.

A Let me try and answer that by stating the question. I think the question here is should there be a high likelihood that the swings of a stochastic risk will balance out over time through rate making. Should there be a high -- should there be a -- should we do rate making, should we design our rates in such a way, that there is a high likelihood that for stochastic risks the swings will balance out over time.

I would answer yes, we should.

Q Thanks.

A But there's many methods available to the Commission to achieve that balance over time. I just wanted to state that. They could use deferred accounting, they could use normalized rate making. There's many methods that the Commission could use to achieve that balance over time. Okay?

Q Good.

A Thank you.

Q I don't want to cut you off.

A No, I know.

Q Okay. Will a major plant outage, like the one in this docket, balance out over time?

A It depends on how you -- again, it's a rate-

A It might. Again, I'd have to consider it. I haven't, in this testimony, done any analysis of the balance over time.

Q Okay. But is it fair to say that if it's not included in the four-year average then it can't balance out over time?

A Not necessarily. Again, I'm not convinced.

As we stated in our testimony, Staff is currently looking at the way forced outages are included in base rates. There's other ways of doing it other than simply using a historic four-year rolling average that may be better than using four-year rolling averages; there's alternative ways of doing it. And one of the considerations that you'd want to look at in weighing those alternative ways of doing it is is it likely to achieve some sort of balance over time?

It's an issue for a normalized rate making. It's a rate-case issue; it's not a deferred-accounting issue.

Q And do you think there is some method out there that would make it so that this particular outage would balance out over time?

A Again, I'm not sure that this particular outage -- again, you'd have to look back and look at likelihood that these types of events will balance out over that period, yes, you would need to know -- you would need to incorporate knowledge about those types of variables that you listed into the modeling on a going-forward basis.

BY MR. TINGEY:

Q Okay. And that wasn't all of the variables, that was just some, right?

A There's, there's -- numerous variables that impact that balancing over time, yeah. And you'd want to pay attention to the ones that likely had the strongest influence or the -- you wouldn't need to account for every little one.

Q That's not how PGE's current rates were set, correct?

A That's correct.

Q Page 16 of your Testimony. I'm sorry, I don't have a line. 4. It says, "Staff considers generating plant forced outages to be a stochastic risk." Right?

Is that all generating plant outages?

A Staff considers generating plant outages that occur during the normal course of business to be a stochastic risk.

Q Okay. So the question was whether that means all plant outages are a stochastic risk.

A No, not all plant outages are a stochastic risk.

Q Okay. Which ones aren't?

A Those that do not occur during the normal course of business.

Q Which is where we started the discussion this morning.

A Which is where we started the discussion this morning.

Q Okay. Was there any discussion of a deadband in the UM 1147 Order?

A I don't know.

Q Why do we need a deadband? Why should there be a deadband?

A Staff discusses the purpose of a deadband in its testimony. That's at page 20, lines 24 through, I guess, the end of the page. 24 through 28. And the purpose of a deadband is to capture the normal business risk that a company is generally exposed to between rate cases.

Q Okay. Any other reasons?

A Not that are coming to mind right here.

Q The deferral statute doesn't require a deadband, does it?

issued in UM 1234.

Q Okay. Good. Then we're back to where we were. If there's no deferral filed, would it be appropriate to include all of those days in the four-year average?

A And I, and I said no, it would not be appropriate to include those in the four-year average calculation, because the four-year average calculation implicitly assumes that, that the type of event would occur once in every four years. What I'm saying is that you'd want to adjust that outage to reflect its extreme nature.

Q What if plant was out for one week each month for a year?

MS. ANDRUS: Objection; it's too vague.

MR. TINGEY: I don't think so.

MS. ANDRUS: What are you asking? What if --

MR. TINGEY: Let me finish.

BY MR. TINGEY:

Q What if it's out for one week each month? Would it be appropriate to include those outages in the four-year rolling average?

A It would depend on the circumstances underlying the fact that the plant was out a week every month for a year. I mean, the purpose of normalizing forced outages in setting base rates is to reflect a normal level of forced outages on a going-forward basis. What I'm suggesting is that the four-year average calculation may not be the best way of doing it. It's the way that we've traditionally done it and it's the way that PGE has done it in recent cases.

What I'm suggesting is is that this deferral application illustrates the weaknesses in that approach. The weakness in that approach is that you can't include -- that it -- one, it doesn't include -- it includes an assumption that whatever goes into that four-year average calculation is going to occur on a going-forward basis at a probability of one in every four years. And what I'm suggesting is that that may not be appropriate.

I think it's pretty clear the last couple of pages of the Testimony here indicates that Staff is willing to consider alternative methods of normalizing outages in base rates. Part of the reason we're willing to consider alternative methods is because of the weaknesses that have been illustrated with using the four-year average calculation.

Q That's not the way current rates were set

A I did, as I discussed earlier, which was speak with Ed Busch, who's an expert on SB 408, and ask him if he felt that our recommendation was appropriate considering how the adjustment will work for SB 408.

Q So how specifically did you include SB 408 in your recommendation?

MS. ANDRUS: Asked and answered. Objection.

MR. TINGEY: I don't think it was answered, so go ahead.

MR. PERKINS: I'd just like to object on the basis of relevance. I don't see how the Senate Bill 408 questions are relevant and I'd just like that noted for the record.

MR. TINGEY: Okay.

BY MR. TINGEY:

Q Go ahead.

A Well, again, I feel like I was pretty clear. I discussed it with Ed. Ed is overseeing the implementation of the SB 408 docket. He went over what our testimony is and what our position is, and I would bow to his expertise in that area, so.

Q Okay. And how would your recommendation have changed if SB 408 didn't exist?

A For this portion of the docket as far as the deferral mechanism itself I don't think that our recommendation would have changed. In the amortization phase of the docket our recommendation for how this issue is handled may be different, I don't know. Again, I would bow to Ed's expertise in that and we would consult with him on it.

Q But the recommendations in your Testimony as filed would not have changed?

A I don't think -- no, I don't think they would have.

Q I was discussing with Mr. Galbraith earlier your Testimony, and he went into a portion about this deadband. Page 20, if you want to look at it. That the purpose of it was to capture the normal business risk exposed -- the Company's exposed to during rate cases, right?

A That's correct.

Q And the effect of that deadband is now significantly different in 2006 than it was in 2005, right?

A On the hypothetical assumptions that you gave me, they would be. Specifically to this docket and how SB 408 gets implemented, it would just be a guess on my part.

years customers got higher rates and some years they got lower rates.

In Oregon, at least, there isn't that sort of a history. The history is that power cost adjustment mechanisms haven't been in place typically in the past, and when they have been used, whatever type they are, they tended not to be in effect for very long, or they tended to be done away with whenever any cost that was concerning the Commission at the time went away.

Q You heard of SB 408?
A I've heard of it.
Q Do you know what it is?
A I understand it has to do with tax treatment of utilities.
Q Okay. Do you know what the proposals on the table are? That it would cause to happen?
A I don't.
Q So I can guess the answer to this question, but we'll ask it anyway. Did you consider the impact of SB 408 in your recommendations in this docket?
A No.
Q Let's take a one-minute break and see if we can get to the end of this real quick; is that okay?
THE WITNESS: That's fine.