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**Douglas C. Tingey**
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May 13, 2009

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

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

**Re: UM 1355 – Investigation into Forecasting Forced Outage Rates**

Attention Filing Center:

Enclosed for filing in the captioned docket are an original and five copies of:

- **Reply Testimony and Exhibits of Mike Niman, Patrick G. Hager and Jay Tinker – PGE Exhibits 200 through 205, 206C, 207-208. PGE Exhibit 206C is confidential and subject to Protective Order 08-549 and is being sent under separate cover. This confidential exhibit should not be posted on the OPUC website.**

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 1355 service list. The confidential portions will be served upon parties that have signed the protective order. Please note that Exhibit 206C will not be sent to Idaho Power nor to their counsel, McDowell & Rackner P.C.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY
Assistant General Counsel

DCT:cbm
Enclosures
cc: Service List-UM 1355

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## I. Introduction

**Q. Please state your names and positions with PGE.**

A. My name is Mike Niman. My position at PGE is manager, Financial Analysis.

My name is Patrick Hager. My position at PGE is manager, Regulatory Affairs.

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

Mr. Hager's and Mr. Tinker's qualifications appear in Section V of PGE Exhibit 100. Mr. Niman's qualifications appear in Section VII.

**Q. Please summarize PGE's position.**

A. In our direct testimony, we discussed the soundness of Staff's 1984 memo for determining the forced outage rate (FOR) and how the methodology is still relevant today. We emphasized that good forecasting practices should lead to more accurate and precise estimates that are necessary for sound rate-making.

Our position has not changed – we still believe that the 1984 Staff Memo provides sound guidance in estimating FORs. We also continue to advocate for sound forecasting practices because they should lead to better estimates. However, while it is clear that all parties agree that, in general, a four-year average of FORs is best for forecasting purposes, it is also clear that parties need more time to work through at least some of the issues that arose towards the end (or even after) the workshops. As we discuss below, PGE believes that some issues could be moved to the current and/or subsequent annual power cost filings while others might be better left undecided or moved to a second phase of this docket.

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

A. The purpose of our testimony is threefold: we discuss the current status of this docket, we rebut some arguments put forth by parties in this docket, and we provide alternatives that PGE believes are superior to some proposals put forth by other parties.

In addition, in PGE Exhibit 204 we provide a summary of our positions regarding the issues in this docket, and we provide a 'proposal matrix' in Section VI, where we summarize the decisions we believe the Commission should make.

**Q. How is your testimony organized?**

A. In Section II, we discuss the proposals regarding the FOR calculation for peaking plants in PGE's power cost model (Monet) and we propose a reasonable alternative solution. We also discuss other parties' proposal to differentiate the high-load and low-load (or weekend/weekday) hours for short-term deferrable maintenance outages in Monet. Last, we discuss whether to use a forecast or an average value to forecast planned maintenance outages (PMO) in Monet.

In Section III, we rebut Staff's recommendation to benchmark FORs against NERC industry data.

In Section IV, we rebut Staff's proposal of alternative factor calculations for coal-fired facilities.

In Section V, we discuss the Parties and PGE's positions on reporting requirements for wind and outages.

In Section VI, we provide a summary of our positions and note specific decisions that PGE suggests the Commission make.

In Section VII, we provide the qualifications for Mr. Niman.

**Q. Does PGE have any concerns regarding this docket?**

A. Yes, we have two general concerns. First, we believe that the scope of this docket has expanded unnecessarily from what the Commission originally asked. Second, we believe that the issues have become very technical without laying a proper foundation in establishing a common goal.

**Q. Please discuss your first concern, that the scope of this docket has expanded too far.**

A. We believe parties have raised issues that go beyond the scope of what the Commission directed the parties to do in Order 07-015. The Order states, "The Commission shall open a new docket to review the appropriate method for determining the forced outage rate for generating plants…" Parties, however, have taken this opportunity to propose a new methodology to forecast planned maintenance outages, which is not part of the forced outage rate determination. Indeed, PGE believes that its current method of estimation for planned maintenance outages is superior to that proposed by other parties. However, the appropriate venue for this discussion is PGE's AUT filing or a general rate case, not a forced outage docket.

**Q. Please discuss your second concern, that the issues have become very technical without a proper foundation.**

A. During the workshops, discussions were generally at the policy level with little emphasis or discussion on the technical aspects. However, the issues became very technical in the first round of testimony. As we discussed in our direct testimony, the scope of the issues did not narrow significantly during the workshops. And, parties' direct testimony further demonstrates not only that the issues have not narrowed, but also that certain parties, although they did not discuss these technical issues during the workshops, now expect the Commission to resolve these highly technical issues without sufficient discussion and analyses.

**Q. Do some of these issues require significant resources and time to research and analyze?**

A. Yes. Some of the issues raised by parties (such as the EFORd methodology) would, if adopted, require a significant effort to incorporate in PGE's power cost model. Even then, the results may have little overall impact. Also, Staff has proposed several new formulas (e.g., factor calculations and wind availability reporting requirements) and methodologies (e.g., benchmarking) in their testimony without demonstrating that any of the proposed formulas will actually improve the forecast. Again, these proposals would require a significant effort to understand and analyze since they were not analyzed or discussed previously.

**Q. Please discuss the additional reporting requirements that have been proposed.**

A. Parties have proposed reporting requirements for wind availability and outages that are very excessive, without indicating why the current information provided by PGE is insufficient or why that additional information could not be acquired through other means, such as data requests.

PGE demonstrated our willingness to provide relevant power cost information to parties by helping develop an agreement for the Minimum Filing Requirements (MFRs) in our AUT filings. Parties have not indicated why or how this extensive MFR information is insufficient.

**Q. Since the issues in this docket have become very technical, parties have not sufficiently explored some of the issues, and others are outside the scope of this docket, how would PGE propose to resolve the issues?**

A. PGE proposes either moving some issues to other power cost related dockets or opening a Phase II to this docket or both. Our recommendations are provided in a table in Section VI.

**Q. What benefit will there be to moving some issues to other power cost dockets or opening a Phase II?**

A. This approach would reduce the number of issues in this docket, provide the parties sufficient time to examine the issues, provide the parties time to develop the analyses to propose appropriate solutions, and provide time for utilities to implement any necessary changes in their power cost models.

## II. Issues for PGE's AUT Filing

**Q. You noted that PGE recommends moving some issues to PGE's Annual Update Tariff (AUT) filings. Which issues does PGE recommend moving?**

A. We recommend that three issues be moved to PGE's Annual Update Tariff (AUT) filings:

- Issue I.A: Should there be a different forced outage rate forecasting method for a peaker plant versus a base load plant?
- Issue IV: What methodology should the Commission adopt for planned maintenance – average versus forecast – of thermal, hydro, and wind plants?
- Issue IV.A: How should this methodology for short-term deferrable maintenance be applied (e.g., high load/low load split, weekend/weekday split)?

**Q. Why does PGE propose to move these issues to the AUT?**

A. As we noted above, issues under consideration in this docket expanded both in number and complexity. As a result, parties have not had sufficient time to explore alternatives or proposed solutions to the issues. Indeed, it will take considerable time to analyze these three issues and they may result in time-consuming enhancements to the Monet model. Moving these issues to the AUT will allow PGE and parties additional time to work on these issues. If these issues are not resolved in PGE's current AUT filing, we would expect to continue to work with parties and to resolve these issues in subsequent filings.

### A. The FOR Calculation for Peaking Plants

**Q. Please explain ICNU's methodology for peaking plants.**

A. ICNU proposes that outage rates for gas-fired plants should be based on the North American Electric Reliability Council (NERC), Equivalent Forced Outage Rate demand (EFORd) methodology. (ICNU/100, Falkenberg/2, lines 20-23) This is the outage rate during the plant's demand period – the time a resource is most likely to run.

**Q. Do you agree with ICNU regarding the EFORd calculation?**

A. No. In concept, we agree that for a plant with a low annual capacity factor, such as Beaver as it currently operates, the EFORd notion will provide a better measure of the forced outage rate for modeling in Monet than the method we currently use. However, the EFORd equation has issues because it is complex and is not transparent. EFORd requires substantial additional plant data that are not currently available and it requires some simplifying assumptions or approximations to be made. In addition, the formula seems intended for a simple one-unit generating plant, where Beaver is more complex, having six units tied to a seventh.

**Q. Can a better method be developed for the Beaver plant?**

A. Yes. We believe that we can develop a better method to address the FOR issue with Beaver that accomplishes the goals of the EFORd concept but in a better, more easily understood way that makes use of existing plant data and takes into account Beaver's unique design configuration. However, although we have started working on a better method, we haven't finished and, as we note later, suggest that this issue be moved to the AUT docket.

**Q. Is the data collection effort for the EFORd calculation problematic?**

A. Yes. The data collection effort required for the standard EFORd calculation is particularly onerous for a plant configured like Beaver. Beaver has six CTs, six heat recovery steam generators (HRSGs), and a steam turbine/generator. The EFORd method has a number of implicit assumptions that would have to be verified continuously against Beaver's performance data. We believe that the same objective can be reached using a much simpler approach.

**Q. Does ICNU discuss any special circumstances for modeling outage rates for combined cycle plants such as PGE's Beaver plant?**

A. Yes. ICNU explains "[c]ombined cycle plants have multiple modes of operation, and may have multiple units at each plant. Further, these plants may have duct firing capability and in some circumstances may be able to operate in either combined cycle or simple cycle mode…To properly assess the outage rate from combined cycle units, ICNU proposes an 'expected value' approach be employed." (ICNU/100, Falkenberg/7-8)

**Q. Are there ways to improve the expected value approach?**

A. Yes. While we agree that the EFORd calculation should account for multiple units at a plant like Beaver, we believe that ICNU's expected value approach (as presented in ICNU's testimony) is too simplistic for a complex plant like Beaver.

**Q. Are you exploring an alternative calculation that is simple but more accurate than the "expected value" approach proposed by ICNU?**

A. Yes. We are exploring an alternative calculation that recognizes that the Beaver plant has several units in a unique configuration and that Beaver dispatches only for combined-cycle use in Monet. Beaver is dispatched only for combined cycle use in Monet and in actual operations, and it operates in simple cycle mode only when starting the plant up and testing. Therefore, if the steam turbine is forced out, the entire Beaver plant is effectively forced out because it is not economic to run the six combustion turbines (CTs) without the steam turbine. Mr. Falkenberg's example of "expected value" requires modifications in order to reflect this consideration.

**Q. What are the main problems that need to be overcome for PGE to be able to apply the EFORd concept to Beaver?**

A. For the Beaver plant, there are two problems that need to be considered and resolved at the same time:

1. Find a practical means to apply the EFORd concept to the Beaver plant.

2. Incorporate the multiple outage states at the Beaver plant in the calculation.

**Q. What do you conclude about the EFORd concept?**

A. In principle, we find the EFORd concept (but not the EFORd formula) reasonable. We emphasize that additional development work is required to produce a practical implementation. We are willing to continue to work with parties to arrive at an EFORd concept that would work for Beaver.

**Q. Does the EFORd calculation apply to PGE's other gas plants?**

A. No. We believe that it only makes practical sense for PGE to pursue the EFORd concept for Beaver at this time because our other gas-fired plants, Coyote Springs Unit 1 and Port Westward, are high annual capacity factor plants. That is, they behave more like base load generating plants, not peaking plants. Thus, they do not have the EFORd issue, which is the condition that as the plant's annual capacity factor declines to very low levels, its standard FOR calculation begins to produce an unrealistically high FOR.

## B. Planned Maintenance Outages

**Q. Please summarize the parties' positions regarding forecasting planned maintenance outages in Monet.**

A. Parties essentially argue that planned maintenance outages (PMOs) for thermal plants should be based on a four-year historical average of actual maintenance outages.

**Q. Do you agree with this proposed methodology?**

A. No. First, as we have already noted, we believe a proposed change in the methodology for PMO is outside the scope of "review[ing] the appropriate method for determining the forced outage rate for generating plants." Second, our current methodology of scheduled planned maintenance is an accurate predictor of PMOs. Third, we do not agree that it is sufficient cause for PGE to change our methodology because PacifiCorp uses a four-year rolling average in their model. There are undoubtedly good reasons for both methods used by the utilities.

**Q. Do you agree with parties that PGE's current forecasting method for planned maintenance schedules over-forecasts planned outages?**

A. No. We disagree with parties that our planned maintenance schedules over-forecast to the extent parties have suggested. And, we strongly disagree that we systematically "game" the forecast, as CUB suggests.

**Q. Does PGE's PMO data demonstrate an accurate and reasonable forecast?**

A. Yes. The data suggest that from year-to-year, especially for the Boardman plant, there is very little difference between the forecast and actual values. The Boardman actual value of zero in 2006 is the year that the major forced outage extended into June, so there was no actual scheduled outage that year. If we remove that year from the comparisons, i.e., from 2002-2008 (excluding 2006), we would <u>under</u> forecast planned maintenance by 10 days.

**Q. Could the proposed rolling average methodology result in a less accurate forecast?**

A. Yes. A four-year rolling average may very likely result in less accurate forecasts for the Boardman plant, given the variation between the average and the actual planned outage, especially if the maintenance during one year was very short (e.g., zero) or very long (e.g., about 60 days), compared to our typical 30 days maintenance.

**Q. CUB Exhibit 102 claims to portray PGE's planned maintenance outages. Is this exhibit correct?**

A. No. CUB Exhibit 102 is not correct because sections of the data from the "Actual" columns are missing. In fact, CUB's exhibit is an incorrect version of a PGE Attachment to an informal OPUC data request, although, it appears that CUB's analysis in testimony uses the values from the original and correct PGE Attachment. PGE Exhibit 203 is the original (and correct) version of the PGE PMO Attachment.

**Q. What is PGE's position regarding forecasting the PMO?**

A. We believe that this issue is outside the scope of the docket. We note that this type of modification to the Monet model could result in a time-consuming enhancement without adding any improvement to the forecast. However, given that parties have raised this issue and given the complexities involved, we propose to continue to work on it with the other parties. We reiterate that the appropriate place to discuss changes in forecasting PMOs is PGE's AUT filing. Nevertheless, should parties wish to continue the PMO discussion, PGE is willing to work with other parties towards resolution.

### C. Short-term Deferrable Maintenance Outages

**Q. Please summarize ICNU's position regarding short-term deferrable maintenance (referred to as high-load/low-load or weekend/weekday split)?**

A. ICNU states "the most straightforward approach would be to include all deferrable maintenance outages in the weekend, or LLH. Given the deferrable nature of these events, simply including them in off-peak or weekend hours would be quite reasonable. An alternative is to differentiate outage rates by weekend or weekday, or between on- and off-peak periods." (ICNU/100, Falkenberg/44)

**Q. Do you agree with ICNU's proposed change?**

A. Yes, to some degree. We found ICNU's testimony sufficiently compelling to warrant an analysis of our own thermal plant data to determine if there is a significant difference in the incidence of forced outages between heavy-load hours (HLH) and light-load hours (LLH) for our plants.

**Q. How do you propose to proceed?**

A. We have already started our analysis, beginning with our Boardman plant. Next, we intend to analyze Colstrip Units 3 and 4, using data from the 2005-2008 four-year period. We are in the process of analyzing these outages, forced outages, and plant derations to determine if the split is a material NVPC issue that would warrant a methodology revision and a Monet modeling enhancement. However, this analysis is complex and time consuming and we do not expect to finish this analysis for months. We are willing to share our analysis with parties as we proceed.

**Q. After you perform the necessary analysis, if you determine the proposed change warrants a modeling enhancement, would this be a simple enhancement to implement?**

A. No. We expect a modeling enhancement of this kind to take considerable effort and time to implement in Monet. The plant dispatch algorithms in Monet do not currently distinguish HLH and LLH other than through the hourly market electric prices. Accommodating the enhancement would require, among other changes, a complete reworking of the "dll" program module that dispatches the gas plants and a revision of the programming code that dispatches the coal plants.

**Q. Do you prefer to keep the model straight-forward?**

A. Advantages of the Monet model include its reliance on straight-forward algorithms, model transparency, and speed of execution. Monet currently provides reasonable forecasts of NVPC without a host of "black-box" features. We hope to retain these characteristics. We prefer to avoid modeling changes that add little value and "fog the model." We believe that it makes sense to balance the value of any potential model enhancement with the effects on model run-time, our ability to validate the model results, and our ability to understand what the model is doing.

**Q. How long would you expect this type of model enhancement to take?**

A. We would expect the enhancement effort to extend beyond the current AUT cycle.

**Q. Is this an example of where the "one-size-fits-all" approach doesn't necessarily apply?**

A. Yes. Different utilities have different power systems with different issues and modeling approaches that are intended to accurately model their situations while keeping the models as simple, flexible, usable and understandable as possible. It may turn out that the coal plant on-/off-peak split issue is material for a utility with a large amount of coal-fired generation but not for another utility with a much smaller amount of coal-fired generation. What may make sense for one utility to include in its model may make no practical sense for another utility to do, but the "one-size-fits-all" approach would ignore this and require the modeling anyway, regardless of its cost-effectiveness.

## III. Forced Outage Rates and Benchmarking

**Q. Staff has proposed that NERC outage rate data should be used as a benchmark when historical years contain extreme events, when outages fall outside a range of what would be "considered normal," or when "significant" outages occur. Does PGE agree with Staff's position on the use of NERC data?**

A. No. As we discuss below, Staff has not provided any evidence that the group of plants used is appropriate for assessing the performance of PGE's thermal plants. In addition, Staff has not considered any other factors that influence forced outage rates, which must be controlled for in their analysis. Finally, we are reluctant to call Staff's procedure "benchmarking" because it's really "distribution censoring," which essentially implies a loss of information from the data set. We also note that there are inherent problems with the NERC data that would take considerable time and effort to understand and hopefully correct.

### A. Arbitrary 10$^{th}$ and 90$^{th}$ Percentiles and an Outage

<u>1. Staff's "Normal" Boundaries are Arbitrary</u>

**Q. Staff suggests using NERC data to create a probability distribution representing a range of possible FORs and to then set upper and lower limits at the 10$^{th}$ and 90$^{th}$ percentiles. Does Staff provide a rationale for using NERC data as a benchmark?**

A. No. Using NERC data with the percentile cut-offs results in an arbitrary benchmark and there is no evidence to indicate that this method will serve as a proper filter for FOR data. In fact, as we discuss below, this method will lead to a biased sample, ensuring that FORs are set <u>lower</u> than they should be.

**Q. Why does Staff choose the 90$^{th}$ and 10$^{th}$ percentiles as the cut-off?**

A. We don't know. These numbers appear to be completely arbitrary. Staff offers no evidence or insight as to why these boundaries are chosen; only that it is important to have "parity" with respect to the boundaries. There is no support for these figures and as we note above, these arbitrary boundaries can in fact introduce a bias. One could possibly argue that the 5$^{th}$ and 95$^{th}$ percentiles are more appropriate since they represent two standard deviations from the mean. However, the bias issues would still remain.

**Q. What is the benefit of using Staff's proposed methodology?**

A. We see no benefit from their proposal. Staff's methodology offers no improvement over the current practice, where parties discuss and debate whether an event is significant since each event is unique.

<u>2. Using NERC 10$^{th}$ or 90$^{th}$ Percentile as a Proxy is Incorrect</u>

**Q. Staff proposes to use NERC FOR data as a substitute for a generating plant's FOR actual data in two instances: if the plant's actual FOR is outside the 10$^{th}$ and 90$^{th}$ percentiles or if the plant has had an outage for a significant period of time. Do you agree with this substitution proposal?**

A. No. First, as we have discussed above, the percentiles recommended by Staff are arbitrary. If, for example, a plant's FOR was at the 95$^{th}$ percentile, then Staff's proposal would have us replace that data point with the 90$^{th}$ percentile from NERC. If we believe that using a four-year rolling average of FOR provides a good FOR forecast, then by using an incorrect FOR for one of the years ensures that the estimated FOR will be second-best.

Second, if a plant's FOR is indeed outside the 95$^{th}$ percentile, then it is likely that there would be analyses by parties as to <u>why</u> that occurred. And, if a deferral was authorized or if the outage(s) were imprudent, then the period would not be included in the FOR calculation anyway. Thus, Staff's proposal doesn't make sense and doesn't improve the forecast over the correct methodology.

**Q. What about the second situation where there is a significant outage?**

A. In this situation, Staff proposes to use the NERC data for years in which significant outages occur. It is unclear whether the entire year's data is replaced with some NERC benchmark and which replacement data are suggested as a replacement. Further, Staff is not clear under what conditions the determination is made to replace any of the data.

<u>3. A Possible Alternative for Removing an Outage</u>

**Q. If the Commission determines that the outage should be removed from the four-year FOR, how does PGE propose to derive the four-year average FOR computation?**

A. One proposal would be to use the most recent rolling four-year average FOR to impute the expected generation during an outage subsequently removed by the Commission.

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

A. Yes. PGE Exhibit 201 is very similar to the example provided by Staff (Staff/100, Brown/21), except we assume the extreme outage takes place in year 5. If the Commission were to determine that an outage should be removed from the four-year average FOR calculation, the expected generation would be imputed based on the prior four-year average FOR calculation. PGE Exhibit 201 provides this calculation as compared to the method used in UE 180.

**Q. Why is this method superior to Staff's suggestion of using NERC data to fill-in the outage period?**

A. This alternative method relies on recent historical plant performance, which we believe provides the best indicator of expected future performance, rather than using industry data to fill-in the missing portion of the 48-month period.

**Q. Are there other possible methods to explore for treating extreme outages within the four-year average FOR computation that use recent historical plant performance?**

A. Yes. Another possible approach would be to calculate the FOR from the calendar year prior to the current four-year period to impute the expected generation during an extreme outage. For example, if significant portions of the year 2006 were missing in the 2005-2008 four-year period, we would use the 2004 FOR to fill in the missing portions of 2006.

**Q. Does PGE believe it is necessary for the Commission to decide how it will compute the four-year average when it determines an outage should be removed?**

A. No. The Commission should decide on a case-by-case basis since every outage is different and may reflect different Commission treatment. Because the Commission has the flexibility and authority to make decisions on a case-by-case basis, which allows for the most effective regulatory outcome, it should not try to standardize responses to an outage event.

Furthermore, the duration of an extreme outage may necessitate different adjustments to the four-year average FOR. The appropriate rate-making response could be different for these, and countless other, scenarios. For this reason, we believe the Commission should make decisions on a case-by-case basis rather than determine a "one size fits all" adjustment methodology. However, if the Commission feels that it should make a decision in this regard, one of the methods we have outlined above should be adopted.

### B. Benchmarking Methodology Introduces a Bias

**Q. Staff believes that benchmarking will more accurately determine if a FOR in the test period is likely to occur and it will provide for a more accurate forecast of the test year. Does PGE agree?**

A. No. Staff has failed to provide evidence to support this assertion. Staff, in fact, stated that they could not find a more statistically significant method than the current four-year rolling average method, so it is unclear why benchmarking is more accurate, necessary, or superior. (Staff/100, page 17)

**Q. Staff claims that benchmarks are a common practice as a test of reasonableness and are therefore appropriate for use in FOR calculations (Staff/200, page 18). Does PGE agree?**

A. No. Staff cites as an example, a completely unrelated benchmarking instance – that of benchmarking costs of a project (wind generation facilities for PacifiCorp) and concludes that because it was appropriate and approved in that instance, that all benchmarking is appropriate. Benchmarking costs related to a project and benchmarking the forecasting of FORs are not comparable analyses and to conclude that benchmarking is useful for all analyses simply because it was appropriate in a non-comparable analysis, is incorrect. Benchmarking related to FORs has, in fact, not been used to date by the Commission and there is no precedent in this area. PGE does not agree that it is a reasonable method. Benchmarking is used to determine best practices and reasonableness, it is not appropriate to use a benchmark as a means of forecasting.

**Q. How does PGE respond to Staff's statement that a utility can file a deferral if it is unsatisfied with the adjustment to its FOR?**

A. Simply because a utility has the option to file a deferral doesn't mean Staff's proposal is reasonable. A deferral can be applied in any instance. The methodology used to forecast FORs should produce the best predictor of the FOR. The Commission also has the ability to make adjustments to the FOR when it is deemed necessary due to an extreme event; therefore, a mechanism to adjust for extreme events already exists. Staff simply claims that their methodology is superior and states that a utility can file a deferral if it believes it should recover additional costs – when Staff instead should provide evidence that their method improves the FOR forecasts, without imposing additional and unnecessary burdens on the utility.

**Q. Staff asserts that using the FOR is a type of retroactive rate-making tool and thus Staff's proposed methodology is further justified because it will be more accurate. (Staff/100, pages 20-21) Does PGE agree?**

A. No. Retroactive ratemaking is essentially adjusting rates based on past actual cost/revenue information in order to assure recovery of past costs. Using historical performance data to forecast a FOR is not equivalent to adjusting rates based on historical cost/revenue. It is simply the best predictor for future outages, a calculation that is necessary to forecast power costs for a future test year. We note that the NERC data Staff proposes to apply would also use historical data. Again, Staff has not proven that their proposed method will deliver a more accurate result than the current four-year rolling average method.

**Q. Do you have any other observations regarding Staff's benchmarking proposal using NERC data?**

A. Yes. Our analysis of the NERC data shows that the data exhibit a right-skewed and fat-tailed distribution, which means that the data are <u>not</u> normally distributed. This type of result is expected since FORs can only fall to zero, but they have the potential to be 100%. In addition, more data points occur to the right of the mean than to the left. Staff notes this as well, stating in reference to 1999 NERC data, "However, as you can see these are not equally distributed on both sides of the mean" (Staff/105, Brown/6).

**Q. Why is it important to note that the data are not normally distributed?**

A. It's important because a procedure that identifies the 10th and 90th percentiles (such as Staff's) and substitutes these percentiles for the "extreme" values effectively biases the expected value of FORs using NERC data. (Staff/105, Brown/1)

**Q. Please explain how Staff's results are biased?**

A. By identifying the 90th and 10th percentiles of a skewed and fat-tailed distribution and treating them equally, the remaining data (presumably representative of expected FOR outcomes based on Staff's testimony) are altered relative to the entire data set, resulting in a lower expected FOR. That is, Staff's methodology provides an implicit downward bias in the NERC FOR data.

**Q. Can you demonstrate this bias?**

A. Yes. In PGE Exhibit 202, we use Staff's data for 600-699 MW coal plants (Staff/105, Brown/1). For each year, we compute the mean (or expected) FOR for all of the data. In 1999, for example, the mean is 6.51%. In addition, we compute the mean for each year, replacing data outside the 90th and 10th percentiles identified by Staff with the 90th and 10th percentile data points, respectively. For example, in 1999 the mean (or expected) FOR is 6.25%, if the data falling outside of the 90th and 10th percentiles are replaced with the 90th and 10th percentile data points. Similar calculations were performed for 2000-2007. For each year, the mean of the data with such a replacement methodology was significantly below that of the entire year's data, indicating that the mean (or expected) outcome has been lowered through Staff's procedure, sometimes substantially.

**Q. If the Commission approves Staff's benchmarking procedure, how do you recommend it be adjusted?**

A. We recommend that the Commission adjust the data used to define the upper bound of allowed FORs to preserve the mean of the entire data set and the expected FOR based on the

NERC data, and thereby remove the bias introduced by Staff's procedure. This procedure is demonstrated in PGE Exhibit 202, where we adjust the data to reasonably preserve the mean FOR outcome. For example, in 1999 the upper bound of allowed FORs would be 15.91%, rather than 13.41% as indicated by Staff. Similar calculations are also shown for 2000-2007.

**Q. Do you have any other suggested modifications to Staff's approach?**

A. Yes. Staff takes a simple (i.e., equally weighted) four-year average of its identified annual 90$^{th}$ and 10$^{th}$ percentile figures. Rather than this approach, we recommend that the Commission adopt an approach that pools all four years of data and that the percentiles (with the adjustment described above) be derived from the combined data. Merging the four years of data preserves the underlying distribution of the data. Staff's averaging procedure adds an unnecessary complication. PGE Exhibit 202 provides an example of this procedure for 2003. Combining the four years of data from 1999-2002 results in a 10$^{th}$ percentile figure of 1.102% (compared to Staff's 1.39% figure) and a 90$^{th}$ percentile figure of 11.51% (compared to Staff's 11.29%). With an adjustment to preserve the mean of the NERC data, the appropriate upper bound to the benchmark is 17.12%. Table 1 below illustrates the result for 2003.

**Table 1**
**(2003 FOR Benchmark)**

| | **Staff 4-year avg of annual 90$^{th}$ and 10$^{th}$ percentiles** | **PGE Derive percentiles based on combined 4 years of data** | **PGE Adjust upper bound benchmark to preserve mean of combined data** |
|---|---|---|---|
| Lower Bound Benchmark | 1.39% | 1.102% | **1.102%** |
| Upper Bound Benchmark | 11.29% | 11.51% | **17.12%** |
| | | | |
| 1999-2002 NERC data mean | 5.77% | 5.79% | 5.79% |
| Replacing data outside 90/10 percentiles | 5.24% | 5.25% | 5.79% |

**Q. You stated that the 10th and 90th percentiles are arbitrary. Could you use other percentiles?**

A. Yes. It makes little sense to arbitrarily choose the 10th and 90th percentiles in relationship to extreme or abnormal events. Standard statistical tests typically rely on 95% or 99% confidence levels, equivalent to two or three standard deviations from the mean; thus, outcomes exceeding the 90th percentile are not considered extreme.

**Q. Please summarize PGE's position.**

A. PGE believes and other parties have agreed that the four-year rolling average is the best predictor of forecast outage rates for future test years. In the event of extreme or abnormal events, PGE believes this is still true because the Commission has discretion to make an adjustment if necessary. The four-year rolling average FOR is already a flexible tool and Staff has offered an arbitrary replacement methodology with little support or evidence that their methodology will in fact improve the forecasting function of the FOR. The Commission should reject Staff's proposal and continue to use the four-year rolling average to predict test year outage rates.

### C. Weaknesses of NERC Sample Data

**Q. Does PGE have concerns regarding the NERC data that Staff suggests be used to develop the benchmark?**

A. Yes. Most of these concerns were addressed in our testimony in UE 180 in PGE Exhibit 1900, pgs. 42-44, and PGE Exhibit 2600, pgs. 21-23. We have provided copies of these pages as PGE Exhibits 207 and 208. Specifically, the NERC data may be inappropriate to use as a benchmark due to:

1. Challenges in selecting an appropriate peer group
2. Degree to which NERC data is objective and verifiable

3. Incentives created by using an FOR benchmark

**Q. Did Staff address any of these concerns regarding NERC data in testimony proposing the benchmark?**

A. No. Our concerns remain that the use of a peer group defined only in terms of the size and type of plant is inappropriate, and that the NERC data are not verifiable and may not be objective due to different utility reporting methods.

**Q. Please describe further your concerns regarding the selection of the peer group.**

A. A benchmark which compares PGE's plants against all plants reporting to NERC of the same fuel type and rough size may include several plants that are in fact not reasonably comparable. The NERC data set includes all vintages of plants fitting the general size/fuel type description. Comparing Boardman to coal plants that could be substantially newer or older than Boardman is not reasonable. Other potential issues which may be reasonably expected to affect plant performance, and hence not provide for a reliable benchmark, include fuel source (Powder River Basin vs. Appalachian coal), general technology, and vintage. Other factors to consider would be plant design, construction, and operations and maintenance practices. As we pointed out in UE 180, NERC advised against the approach for which Staff continues to advocate as being overly simplistic for purposes of benchmarking.

**Q. Please describe further why NERC data may not be objective.**

A. We discussed in UE 180, the NERC data may not be objective due to the flexibility that reporting parties have in deciding whether an outage is planned or forced or whether reporting utilities are all following the same conventions generally to report forced outages.

**Q. Is this problem exacerbated by the lack of access to the raw data reported to NERC?**

A. Yes. The underlying data reported by NERC cannot be verified by PGE or any other party to this regulatory proceeding. NERC does not supply parties with the actual reports provided by reporting entities. Even if such reports were made available, it would take a Herculean effort to attempt to verify that the actual plant performance of reporting utilities was consistent with that reported to NERC.

**Q. What is the consequence of such data not being verifiably objective?**

A. Any benchmark used based on such data may contain substantial bias. Because of this potential for bias, it is unreasonable to benchmark PGE's facilities against NERC data. Further, Staff does not show that benchmarking against data that are not objective or verifiable provides for a more accurate test year forecast of PGE's power costs, as is claimed.

**Q. Do you have any other concerns about the use of NERC data as a benchmark as proposed by Staff?**

A. Yes. Benchmarking, when done reasonably, should highlight not only how performance matches up against peers, but more importantly should suggest ways to improve (if deficient) by highlighting <u>how</u> those peers achieved the results that they achieved.

**Q. Does Staff's benchmarking proposal provide the potential for this type of learning?**

A. No. Again, since the NERC data are not objective and verifiable, and since it provides no basis for discovering how the data set results were achieved, it provides no opportunity to improve on results if a deficiency were found.

**Q. Could benchmarked FORs also provide perverse regulatory incentives?**

A. Potentially. The operators of a plant may seek to do additional planned maintenance to achieve lower FORs.

**Q. Is Staff' benchmark methodology truly a benchmark?**

A. No. The manner in which the data are implemented does not make the methodology a "true" benchmark. A more appropriate label for this methodology might be a FOR "ceiling and floor." The way the data are used in this context is to decrease or increase (or "reset") the FOR in the forecasting model when, and if, a FOR falls outside "arbitrary" percentiles.

## IV. Staff's Alternative Factor Calculations for Coal-Fired Facilities

**Q. What is Staff's position on the forecasting methodology that the Commission should adopt (Consolidated Issue 1)?**

A. Staff does not support the formula that has been in practice since 1984 to calculate forced outage rates (FORs). Instead, Staff now proposes three new formulas – one each for the forced outage rate, the planned outage rate, and the deferrable maintenance outage rate – to calculate the outage rate for coal-fired facilities. This change in methodology would apply to all utilities. (Staff/100, Brown/9, lines 21-26)

**Q. Do you agree with Staff's proposed formula change?**

A. No. First, it's not clear why the three new formulas are relevant or, second, if they improve the current calculations or even the FOR forecast. Indeed, Staff does not provide evidence that the new formulas are more accurate. Without that evidence, recalculating each plant's FOR will "undo" the work we diligently put forth in the NVPC MFRs with no value added. For example, PGE would need to review the data for each of our thermal plants to ensure that the data can still be used with the new formulas. We would then have to make numerous calculations and reproduce the extensive supporting documentation and explanations included in the MFRs.

**Q. What is PGE's position on the forced outage rate formula?**

A. We propose to continue with the existing formulas to calculate FORs[1].

**Q. Did PacifiCorp and PGE issue a set of data requests so that Staff could clarify how the three new formulas would be used in the NVPC calculation?**

A. Yes. PacifiCorp issued a series of questions in Data Request No. 3 to ascertain how the three new formulas on top of page 10 of Staff Exhibit 100 apply to the FOR. PGE also

[1] We note that PGE has agreed to consider the EFORd issue for Beaver and the deferrable maintenance outage on- / off-peak split issue for Boardman and Colstrip Units 3 and 4, as we discussed earlier in this testimony.

requested Staff provide this information. In PacifiCorp's Data Request No. 4, it asks Staff to explain whether there are differences in the value of FORs and if so, why. PGE requested a copy of the Staff's response and it is not due to PGE until after this testimony is filed.

## V. Wind and Outage Reporting Requirement

**Q. Parties have suggested extensive additions to the amount of information that PGE currently provides in its filings. What plant forced outage information does PGE currently provide in its AUT filings, such as UE 208?**

A. PGE provided its thermal plant FOR calculations, formulas, and supporting documentation as part of the Minimum Filing Requirements (MFRs). PGE Exhibit 205 is a list of the information that PGE includes in its MFRs. The MFRs include detailed descriptions of the inputs to the Monet model and Volume 3 – Thermal Plant Inputs – of the MFRs includes information about thermal FORs. As part of the MFRs, we also provided thorough documentation of the inputs to Monet as well as a copy of the model.

**Q. What new wind availability information did you include in the MFRs?**

A. In addition to the outage information provided, PGE agreed to provide an annual report of wind availability, based on discussions with Staff, CUB, and ICNU in the workshops. The wind availability report provided in our MFRs is confidential PGE Exhibit 206C. This report contains information regarding wind availability and production of our Biglow Canyon Wind Farm Phase 1 facility.

### A. Wind Availability Reporting Requirements

**Q. Can you briefly explain what wind availability reporting requirements that Staff and ICNU have proposed?**

A. Yes. Staff proposes a wind availability report for each facility that the utility owns and operates. Staff states the reports should include maximum net output of the facility (given actual wind conditions in a calendar year), lack of availability due to planned maintenance, lack of availability due to line loss, and lack of availability due to forced outage, turbine failure, or non-scheduled maintenance. These factors will then be calculated to produce an actual capacity factor.

ICNU proposes the utilities report annually and specific information similar to that reported for thermal operating plants.

**Q. What is your recommendation for wind reporting requirements?**

A. We strongly recommend that the Commission accept the wind farm availability information as provided by the turbine vendor(s) per the service agreements and automatically calculated by the turbine control software. This is the availability that we use for our internal plant availability reporting. The contract availability is a true reflection of equipment availability and accounts for equipment failure hours on an individual turbine basis. This automatically calculated availability also accounts for time the equipment is out of service for scheduled maintenance. It is accurate and easy to provide.

Using a different method to calculate availability will require additional staff time as well as the development of different calculation programs and/or methods but will not likely improve the information required.

**Q. Is the "lack of availability due to line losses" a driver of the actual plant availability?**

A. No. If Staff's "lack of availability due to line loss" is for the loss of the transmission line between the Biglow Canyon substation and Portland, this would occur only on very rare situations, amounting to less than 3-4 hours per year. We do not believe this factor is a driver of the availability and should not require separate reporting.

**Q. Which does Staff suggest providing in the wind availability report: the maximum hourly generation during an hour or the net output of the plant at the switchyard during the year?**

A. It's unclear. Staff makes a recommendation, but we don't know if Staff is suggesting a maximum hourly generation during an hour of the year or the net output of the plant at the switchyard during the year. If it is the output during the year, then the word "maximum" has no meaning. PGE can provide net output from the plant on an annual basis. This information is recorded by the billing quality meter at our substation.

**Q. You said you provided an annual wind availability report in the MFRs, what information is provided in this report?**

A. This annual report provides data on wind availability and production of our Biglow Canyon Wind Farm Phase 1 facility. The first set of data in this report provides total available hours, supplier controlled hours, supplier uncontrolled hours, and Vestas contract availability by month.

The second set of data provides a comparison of 2008 actual production to estimated production by month. This includes:

- Actual Net MWh to BPA from Substation
- Actual Capacity Factor Percentage
- Estimated Generation MWh
- Estimated Capacity Factor Percentage

**Q. Can you determine the net and gross generation?**

A. Yes. We can determine gross generation by totaling the individual unit generation from our SCADA system, now that the system is fully operational. Also, we are able to record the plant net as measured at the substation output, which is available in the annual report as discussed above.

### B. Outage Reporting Requirements

**Q. Can you briefly explain what outage reporting requirements other parties have proposed?**

A. Yes. CUB proposed adopting a standardized reporting requirement for plant outages. They state, "A detailed report should be filed for each plant outage that is in excess of 24 hours in length." CUB then details an extensive list of items that should be included in a report. (CUB/100, Jenks/11-12)

ICNU proposed a root cause analysis for all outages longer than one week. Also, ICNU proposed the utilities report standard NERC data for all thermal, hydro, and wind resources. (ICNU/100, Falkenberg/61, lines 11-18)

**Q. Do these requirements seem excessive?**

A. Yes. CUB and ICNU's reporting requirements seem excessive in light of the detailed content we currently provide in the MFRs. We worked with ICNU (and other parties) to determine the information that would be included in the MFRs. We now provide this information to parties at the time of the filing, or no later than 15 days following.

**Q. Can parties file a data request for information that they believe exists and would like to examine?**

A. Yes. If parties believe we are filing information with NERC and any other regulatory entity, they can request a copy of this information with a data request.

## VI. Conclusions

**Q. Please summarize your recommendations.**

A. We believe that the issues in this docket have expanded beyond the Commission's directive and have become too technical without a proper foundation of thorough discussion and analysis. We believe that some of these issues can be better discussed and analyzed in other dockets, such as PGE's AUT filings, and have indicated so in a summary table below. Other issues, however, should be either rejected, or modified, or moved to a "Phase 2" of this docket for clarification, further analysis, and/or resolution.

**PGE's Summary Proposals Matrix**

| Consolidated Issue | Primary Recommendation | Alternative Recommendation | Alternative Recommendation: UM 1355 Phase II |
|---|---|---|---|
| **Planned Maintenance Outages** | Determine PMO is beyond the scope of this docket | Move the issue to the AUT | Move the issue to a Phase II of UM 1355 |
| **Gas Peaker FOR (EFORd and Expected value)** | Move the issue to the AUT | | Move the issue to a Phase II of UM 1355 |
| **Deferred Maintenance** | Move the issue to the AUT | | Move the issue to a Phase II of UM 1355 |
| **Benchmarking 4-Yr FOR against 90/10 NERC Data** | Reject Staff's proposal. 4-Yr FORs do not require benchmarking since they provide the best forecast, and NERC data do not provide appropriate peer group for benchmarking. | Replace 90$^{th}$ percentile calc with adjusted upper bound and use 4 years of NERC data combined | |
| **Replacing outage data removed by the Commission to establish 4-yr FOR** | Reject Staff's proposal to replace outage data with NERC data. Commission has flexibility to decide on case-by-case basis | Replace outage data removed by the Commission with historical plant performance data. We suggest two alternatives. | |
| **Alternative coal factor calculations** | Reject Staff's proposal. Existing FOR formulas are appropriate | | |
| **Wind and Outage Reporting Requirement** | Reject Parties' proposals to expand reporting requirements. Current MFRs provide sufficient documentation. | | |

## VII. Qualifications

**Q. Mr. Niman, please state your educational background and experience.**

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

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

A. Yes.

**List of Exhibits**

| **PGE Exhibit** | **Description** |
|---|---|
| Exhibit 201 | Proposed Calculation for an Extreme Outage |
| Exhibit 202 | Alternative Calculation of Staff's Benchmark Methodology |
| Exhibit 203 | Planned Maintenance Outages |
| Exhibit 204 | Reference List |
| Exhibit 205 | Minimum Filing Requirements (MFRs) provided by PGE |
| **Exhibit 206C** | **Wind Availability Report for Biglow Canyon Phase I** |
| Exhibit 207 | UE 180/UE 181/UE 184 PGE Exhibit 1900, pgs. 42-44 |
| Exhibit 208 | UE 180/UE 181/UE 184 PGE Exhibit 2600, pgs. 21-23 |

**PGE Proposal for Treating Outages Removed by the Commission from 4-Year Average**

100 MW Plant

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| Total forced outage hours | 60,000 | 100,000 | 50,000 | 75,000 | 400,000 |
| Total MWH in one year | 876,000 | 876,000 | 876,000 | 876,000 | 876,000 |
| Forced outage rate | 7% | 11% | 6% | 9% | 46% |
| Rolling 4-Year Average | | | | 8% | 18% |

Commission decision in year 5, removes 300,000 hours from the outage calculation

**Method used in UE-180**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| Total forced outage hours | 60,000 | 100,000 | 50,000 | 75,000 | 100,000 |
| Total MWH in one year | 876,000 | 876,000 | 876,000 | 876,000 | 576,000 |
| Forced outage rate | 7% | 11% | 6% | 9% | 17% |
| Rolling 4-Year Average | | | | 8% | 11% |

**PGE Proposal - Use prior 4 year average to impute expected generation during outage**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 |
|---|---|---|---|---|---|
| Total forced outage hours | 60,000 | 100,000 | 50,000 | 75,000 | 124,401 |
| Total MWH in one year | 876,000 | 876,000 | 876,000 | 876,000 | 876,000 |
| Forced outage rate | 7% | 11% | 6% | 9% | 14% |
| Rolling 4-Year Average | | | | 8% | 10% |

where 124,401 = 100,000 + (300,000 * Prior 4-yr avg FOR of 8%)

**Coal Fossil Units 600-699MW**
**NERC Data**

| Units | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.69 | 0.91 | 0.01 | 0.00 | 0.42 | 0.19 | 0.10 | 0.22 | 0.07 |
| 2 | 1.06 | 1.00 | 0.33 | 0.09 | 0.50 | 0.38 | 0.46 | 0.47 | 0.18 |
| 3 | 1.33 | 1.62 | 0.60 | 0.54 | 0.63 | 0.96 | 0.84 | 0.60 | 0.21 |
| 4 | 1.81 | 1.67 | 0.88 | 0.63 | 0.75 | 1.01 | 0.88 | 0.62 | 0.24 |
| 5 | 1.91 | 1.70 | 0.99 | 0.64 | 1.32 | 1.21 | 1.14 | 0.71 | 0.99 |
| 6 | 1.94 | 1.77 | 1.00 | 0.70 | 1.35 | 1.23 | 1.30 | 1.27 | 1.04 |
| 7 | 1.97 | 2.00 | 1.14 | 0.72 | 1.36 | 1.42 | 1.60 | 1.33 | 1.22 |
| 8 | 2.42 | 2.04 | 1.21 | 0.79 | 1.42 | 1.48 | 1.69 | 1.40 | 1.25 |
| 9 | 2.46 | 2.10 | 1.26 | 0.83 | 1.54 | 1.59 | 1.81 | 1.64 | 1.50 |
| 10 | 2.49 | 2.15 | 1.40 | 0.92 | 1.59 | 1.67 | 2.03 | 1.91 | 1.95 |
| 11 | 2.57 | 2.50 | 1.90 | 0.94 | 1.60 | 1.93 | 2.07 | 1.94 | 2.00 |
| 12 | 2.77 | 2.53 | 1.92 | 0.98 | 1.70 | 1.97 | 2.39 | 2.03 | 2.05 |
| 13 | 2.92 | 2.54 | 2.04 | 1.12 | 1.78 | 2.06 | 2.46 | 2.06 | 2.17 |
| 14 | 2.99 | 2.60 | 2.15 | 1.21 | 1.79 | 2.26 | 2.51 | 2.41 | 2.41 |
| 15 | 3.11 | 2.68 | 2.19 | 1.30 | 1.83 | 2.40 | 2.62 | 2.58 | 2.61 |
| 16 | 3.12 | 2.81 | 2.37 | 1.37 | 1.91 | 2.57 | 2.85 | 2.94 | 2.99 |
| 17 | 3.22 | 3.03 | 2.56 | 1.42 | 2.08 | 2.58 | 2.94 | 2.98 | 3.29 |
| 18 | 3.25 | 3.06 | 3.25 | 1.55 | 2.29 | 2.70 | 3.00 | 3.06 | 3.40 |
| 19 | 3.47 | 4.18 | 3.35 | 1.59 | 2.53 | 2.97 | 3.05 | 3.24 | 3.46 |
| 20 | 3.71 | 4.22 | 3.84 | 1.64 | 2.75 | 3.14 | 3.38 | 3.33 | 3.75 |
| 21 | 3.89 | 4.34 | 3.93 | 1.72 | 3.18 | 3.34 | 3.63 | 3.48 | 3.79 |
| 22 | 4.01 | 4.51 | 4.33 | 1.86 | 3.35 | 3.36 | 4.03 | 3.87 | 3.86 |
| 23 | 4.02 | 4.80 | 4.50 | 1.89 | 3.91 | 3.45 | 4.12 | 4.20 | 4.21 |
| 24 | 4.26 | 4.89 | 4.60 | 1.99 | 3.97 | 3.67 | 4.33 | 4.40 | 4.71 |
| 25 | 4.37 | 5.00 | 4.62 | 2.70 | 4.42 | 3.71 | 4.34 | 4.47 | 5.04 |
| 26 | 4.56 | 5.05 | 4.68 | 2.79 | 4.50 | 3.80 | 4.88 | 4.62 | 5.11 |
| 27 | 4.95 | 5.14 | 4.78 | 2.99 | 5.02 | 3.84 | 4.90 | 4.65 | 5.21 |
| 28 | 4.98 | 5.32 | 4.90 | 3.10 | 5.22 | 4.06 | 5.11 | 4.71 | 5.45 |
| 29 | 5.23 | 5.67 | 5.12 | 3.17 | 5.30 | 4.59 | 5.12 | 4.97 | 5.52 |
| 30 | 5.33 | 5.68 | 5.47 | 3.41 | 5.52 | 4.67 | 5.25 | 5.15 | 5.55 |
| 31 | 5.56 | 6.02 | 5.58 | 3.50 | 5.83 | 4.71 | 5.42 | 5.26 | 5.67 |
| 32 | 5.78 | 6.14 | 5.87 | 3.77 | 5.87 | 4.98 | 5.45 | 5.40 | 5.68 |
| 33 | 5.94 | 6.23 | 5.98 | 3.84 | 5.89 | 5.07 | 5.73 | 5.60 | 5.80 |
| 34 | 5.95 | 6.29 | 6.18 | 4.17 | 6.02 | 5.09 | 5.82 | 5.92 | 6.21 |
| 35 | 6.37 | 6.37 | 6.90 | 4.42 | 6.05 | 5.14 | 5.95 | 5.93 | 6.40 |
| 36 | 6.82 | 6.69 | 7.31 | 4.44 | 6.07 | 5.25 | 5.96 | 6.30 | 6.98 |
| 37 | 7.10 | 7.00 | 7.44 | 4.52 | 6.49 | 5.29 | 6.50 | 6.50 | 7.61 |
| 38 | 7.36 | 7.10 | 7.62 | 4.61 | 6.78 | 5.63 | 6.62 | 6.52 | 8.00 |
| 39 | 7.54 | 7.11 | 7.69 | 4.76 | 7.03 | 5.68 | 6.64 | 6.76 | 8.57 |
| 40 | 7.86 | 7.27 | 7.83 | 4.90 | 7.18 | 5.90 | 7.24 | 6.87 | 8.62 |
| 41 | 8.46 | 7.40 | 7.87 | 5.51 | 7.47 | 6.46 | 7.45 | 6.91 | 8.90 |
| 42 | 8.48 | 8.68 | 7.90 | 5.63 | 7.79 | 6.62 | 7.66 | 7.05 | 9.37 |
| 43 | 8.92 | 8.97 | 7.91 | 5.68 | 8.08 | 6.95 | 7.73 | 7.07 | 9.53 |
| 44 | 9.08 | 9.31 | 8.04 | 6.07 | 8.12 | 7.24 | 7.96 | 7.46 | 9.69 |
| 45 | 9.57 | 9.97 | 8.70 | 6.73 | 8.78 | 7.76 | 8.00 | 10.26 | 10.08 |
| 46 | 10.17 | 10.39 | 9.57 | 7.37 | 9.37 | 7.91 | 8.34 | 10.58 | 10.36 |
| 47 | 10.57 | 10.86 | 10.68 | 8.02 | 10.80 | 8.05 | 8.65 | 10.88 | 10.37 |
| 48 | 10.68 | 11.20 | 11.51 | 8.35 | 10.83 | 8.41 | 9.64 | 11.35 | 10.45 |
| 49 | 11.17 | 11.66 | 12.03 | 9.42 | 11.23 | 8.52 | 10.40 | 12.36 | 10.77 |
| 50 | 11.51 | 12.13 | 14.02 | 10.51 | 13.15 | 10.42 | 10.60 | 12.45 | 11.45 |
| 51 | 13.17 | 14.05 | 18.34 | 10.71 | 13.92 | 10.88 | 11.65 | 17.18 | 11.83 |
| 52 | 13.78 | 14.38 | | 17.06 | 16.55 | 12.02 | 11.74 | 22.40 | 13.93 |
| 53 | 13.97 | 14.48 | | 17.74 | 22.11 | 12.52 | 22.60 | 23.23 | 14.20 |
| 54 | 14.22 | 17.86 | | 34.51 | 23.34 | 12.70 | 29.51 | 23.72 | 14.47 |
| 55 | 16.71 | 23.00 | | | | 13.55 | | 24.93 | 17.54 |
| 56 | 19.24 | 36.55 | | | | 14.93 | | | 23.25 |
| 57 | 20.55 | | | | | 16.37 | | | 23.85 |
| 58 | | | | | | 30.94 | | | |
| | | | | | | | | | |
| **90th percentile** | **13.41** | **13.09** | **9.57** | **9.10** | **11.11** | **12.17** | **10.17** | **12.41** | **12.67** |
| **10th percentile** | **1.96** | **1.89** | **1.00** | **0.71** | **1.35** | **1.36** | **1.39** | **1.29** | **1.15** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **4 year average 90th percentile** | | | | **11.29** | **10.72** | **10.49** | **10.64** | **11.47** | **11.86** |
| **4 year average 10th percentile** | | | | **1.39** | **1.24** | **1.11** | **1.20** | **1.35** | **1.30** |
| Average (All Data) | 6.51 | 6.87 | 5.22 | 4.46 | 5.75 | 5.23 | 5.71 | 6.37 | 6.58 |
| 4-year average | | | | 5.77 | 5.57 | 5.16 | 5.29 | 5.76 | 5.97 |

**Coal Fossil Units 600-699MW**
**NERC Data**

| Units | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 2 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 3 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 4 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 5 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 6 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 7 | 1.97 | 2.00 | 1.14 | 0.72 | 1.36 | 1.42 | 1.60 | 1.33 | 1.22 |
| 8 | 2.42 | 2.04 | 1.21 | 0.79 | 1.42 | 1.48 | 1.69 | 1.40 | 1.25 |
| 9 | 2.46 | 2.10 | 1.26 | 0.83 | 1.54 | 1.59 | 1.81 | 1.64 | 1.50 |
| 10 | 2.49 | 2.15 | 1.40 | 0.92 | 1.59 | 1.67 | 2.03 | 1.91 | 1.95 |
| 11 | 2.57 | 2.50 | 1.90 | 0.94 | 1.60 | 1.93 | 2.07 | 1.94 | 2.00 |
| 12 | 2.77 | 2.53 | 1.92 | 0.98 | 1.70 | 1.97 | 2.39 | 2.03 | 2.05 |
| 13 | 2.92 | 2.54 | 2.04 | 1.12 | 1.78 | 2.06 | 2.46 | 2.06 | 2.17 |
| 14 | 2.99 | 2.60 | 2.15 | 1.21 | 1.79 | 2.26 | 2.51 | 2.41 | 2.41 |
| 15 | 3.11 | 2.68 | 2.19 | 1.30 | 1.83 | 2.40 | 2.62 | 2.58 | 2.61 |
| 16 | 3.12 | 2.81 | 2.37 | 1.37 | 1.91 | 2.57 | 2.85 | 2.94 | 2.99 |
| 17 | 3.22 | 3.03 | 2.56 | 1.42 | 2.08 | 2.58 | 2.94 | 2.98 | 3.29 |
| 18 | 3.25 | 3.06 | 3.25 | 1.55 | 2.29 | 2.70 | 3.00 | 3.06 | 3.40 |
| 19 | 3.47 | 4.18 | 3.35 | 1.59 | 2.53 | 2.97 | 3.05 | 3.24 | 3.46 |
| 20 | 3.71 | 4.22 | 3.84 | 1.64 | 2.75 | 3.14 | 3.38 | 3.33 | 3.75 |
| 21 | 3.89 | 4.34 | 3.93 | 1.72 | 3.18 | 3.34 | 3.63 | 3.48 | 3.79 |
| 22 | 4.01 | 4.51 | 4.33 | 1.86 | 3.35 | 3.36 | 4.03 | 3.87 | 3.86 |
| 23 | 4.02 | 4.80 | 4.50 | 1.89 | 3.91 | 3.45 | 4.12 | 4.20 | 4.21 |
| 24 | 4.26 | 4.89 | 4.60 | 1.99 | 3.97 | 3.67 | 4.33 | 4.40 | 4.71 |
| 25 | 4.37 | 5.00 | 4.62 | 2.70 | 4.42 | 3.71 | 4.34 | 4.47 | 5.04 |
| 26 | 4.56 | 5.05 | 4.68 | 2.79 | 4.50 | 3.80 | 4.88 | 4.62 | 5.11 |
| 27 | 4.95 | 5.14 | 4.78 | 2.99 | 5.02 | 3.84 | 4.90 | 4.65 | 5.21 |
| 28 | 4.98 | 5.32 | 4.90 | 3.10 | 5.22 | 4.06 | 5.11 | 4.71 | 5.45 |
| 29 | 5.23 | 5.67 | 5.12 | 3.17 | 5.30 | 4.59 | 5.12 | 4.97 | 5.52 |
| 30 | 5.33 | 5.68 | 5.47 | 3.41 | 5.52 | 4.67 | 5.25 | 5.15 | 5.55 |
| 31 | 5.56 | 6.02 | 5.58 | 3.50 | 5.83 | 4.71 | 5.42 | 5.26 | 5.67 |
| 32 | 5.78 | 6.14 | 5.87 | 3.77 | 5.87 | 4.98 | 5.45 | 5.40 | 5.68 |
| 33 | 5.94 | 6.23 | 5.98 | 3.84 | 5.89 | 5.07 | 5.73 | 5.60 | 5.80 |
| 34 | 5.95 | 6.29 | 6.18 | 4.17 | 6.02 | 5.09 | 5.82 | 5.92 | 6.21 |
| 35 | 6.37 | 6.37 | 6.90 | 4.42 | 6.05 | 5.14 | 5.95 | 5.93 | 6.40 |
| 36 | 6.82 | 6.69 | 7.31 | 4.44 | 6.07 | 5.25 | 5.96 | 6.30 | 6.98 |
| 37 | 7.10 | 7.00 | 7.44 | 4.52 | 6.49 | 5.29 | 6.50 | 6.50 | 7.61 |
| 38 | 7.36 | 7.10 | 7.62 | 4.61 | 6.78 | 5.63 | 6.62 | 6.52 | 8.00 |
| 39 | 7.54 | 7.11 | 7.69 | 4.76 | 7.03 | 5.68 | 6.64 | 6.76 | 8.57 |
| 40 | 7.86 | 7.27 | 7.83 | 4.90 | 7.18 | 5.90 | 7.24 | 6.87 | 8.62 |
| 41 | 8.46 | 7.40 | 7.87 | 5.51 | 7.47 | 6.46 | 7.45 | 6.91 | 8.90 |
| 42 | 8.48 | 8.68 | 7.90 | 5.63 | 7.79 | 6.62 | 7.66 | 7.05 | 9.37 |
| 43 | 8.92 | 8.97 | 7.91 | 5.68 | 8.08 | 6.95 | 7.73 | 7.07 | 9.53 |
| 44 | 9.08 | 9.31 | 8.04 | 6.07 | 8.12 | 7.24 | 7.96 | 7.46 | 9.69 |
| 45 | 9.57 | 9.97 | 8.70 | 6.73 | 8.78 | 7.76 | 8.00 | 10.26 | 10.08 |
| 46 | 10.17 | 10.39 | 9.57 | 7.37 | 9.37 | 7.91 | 8.34 | 10.58 | 10.36 |
| 47 | 10.57 | 10.86 | 9.57 | 8.02 | 10.80 | 8.05 | 8.65 | 10.88 | 10.37 |
| 48 | 10.68 | 11.20 | 9.57 | 8.35 | 10.83 | 8.41 | 9.64 | 11.35 | 10.45 |
| 49 | 11.17 | 11.66 | 9.57 | 9.10 | 11.11 | 8.52 | 10.17 | 12.36 | 10.77 |
| 50 | 11.51 | 12.13 | 9.57 | 9.10 | 11.11 | 10.42 | 10.17 | 12.41 | 11.45 |
| 51 | 13.17 | 13.09 | 9.57 | 9.10 | 11.11 | 10.88 | 10.17 | 12.41 | 11.83 |
| 52 | 13.41 | 13.09 | | 9.10 | 11.11 | 12.02 | 10.17 | 12.41 | 12.67 |
| 53 | 13.41 | 13.09 | | 9.10 | 11.11 | 12.17 | 10.17 | 12.41 | 12.67 |
| 54 | 13.41 | 13.09 | | 9.10 | 11.11 | 12.17 | 10.17 | 12.41 | 12.67 |
| 55 | 13.41 | 13.09 | | | | 12.17 | | 12.41 | 12.67 |
| 56 | 13.41 | 13.09 | | | | 12.17 | | | 12.67 |
| 57 | 13.41 | | | | | 12.17 | | | 12.67 |
| 58 | | | | | | 12.17 | | | |
| Average - Extreme values replaced w/ Staff calc'd 90/10 percentiles | 6.25 | 6.17 | 4.90 | 3.65 | 5.18 | 5.13 | 5.12 | 5.54 | 6.10 |
| Average (All Data) | 6.51 | 6.87 | 5.22 | 4.46 | 5.75 | 5.23 | 5.71 | 6.37 | 6.58 |
| Delta (Staff - All Data) | -0.26 | -0.70 | -0.32 | -0.81 | -0.56 | -0.11 | -0.59 | -0.83 | -0.47 |

**Coal Fossil Units 600-699MW**
**NERC Data**

| Units | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 2 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 3 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 4 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 5 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 6 | 1.96 | 1.89 | 1.00 | 0.71 | 1.35 | 1.36 | 1.39 | 1.29 | 1.15 |
| 7 | 1.97 | 2.00 | 1.14 | 0.72 | 1.36 | 1.42 | 1.60 | 1.33 | 1.22 |
| 8 | 2.42 | 2.04 | 1.21 | 0.79 | 1.42 | 1.48 | 1.69 | 1.40 | 1.25 |
| 9 | 2.46 | 2.10 | 1.26 | 0.83 | 1.54 | 1.59 | 1.81 | 1.64 | 1.50 |
| 10 | 2.49 | 2.15 | 1.40 | 0.92 | 1.59 | 1.67 | 2.03 | 1.91 | 1.95 |
| 11 | 2.57 | 2.50 | 1.90 | 0.94 | 1.60 | 1.93 | 2.07 | 1.94 | 2.00 |
| 12 | 2.77 | 2.53 | 1.92 | 0.98 | 1.70 | 1.97 | 2.39 | 2.03 | 2.05 |
| 13 | 2.92 | 2.54 | 2.04 | 1.12 | 1.78 | 2.06 | 2.46 | 2.06 | 2.17 |
| 14 | 2.99 | 2.60 | 2.15 | 1.21 | 1.79 | 2.26 | 2.51 | 2.41 | 2.41 |
| 15 | 3.11 | 2.68 | 2.19 | 1.30 | 1.83 | 2.40 | 2.62 | 2.58 | 2.61 |
| 16 | 3.12 | 2.81 | 2.37 | 1.37 | 1.91 | 2.57 | 2.85 | 2.94 | 2.99 |
| 17 | 3.22 | 3.03 | 2.56 | 1.42 | 2.08 | 2.58 | 2.94 | 2.98 | 3.29 |
| 18 | 3.25 | 3.06 | 3.25 | 1.55 | 2.29 | 2.70 | 3.00 | 3.06 | 3.40 |
| 19 | 3.47 | 4.18 | 3.35 | 1.59 | 2.53 | 2.97 | 3.05 | 3.24 | 3.46 |
| 20 | 3.71 | 4.22 | 3.84 | 1.64 | 2.75 | 3.14 | 3.38 | 3.33 | 3.75 |
| 21 | 3.89 | 4.34 | 3.93 | 1.72 | 3.18 | 3.34 | 3.63 | 3.48 | 3.79 |
| 22 | 4.01 | 4.51 | 4.33 | 1.86 | 3.35 | 3.36 | 4.03 | 3.87 | 3.86 |
| 23 | 4.02 | 4.80 | 4.50 | 1.89 | 3.91 | 3.45 | 4.12 | 4.20 | 4.21 |
| 24 | 4.26 | 4.89 | 4.60 | 1.99 | 3.97 | 3.67 | 4.33 | 4.40 | 4.71 |
| 25 | 4.37 | 5.00 | 4.62 | 2.70 | 4.42 | 3.71 | 4.34 | 4.47 | 5.04 |
| 26 | 4.56 | 5.05 | 4.68 | 2.79 | 4.50 | 3.80 | 4.88 | 4.62 | 5.11 |
| 27 | 4.95 | 5.14 | 4.78 | 2.99 | 5.02 | 3.84 | 4.90 | 4.65 | 5.21 |
| 28 | 4.98 | 5.32 | 4.90 | 3.10 | 5.22 | 4.06 | 5.11 | 4.71 | 5.45 |
| 29 | 5.23 | 5.67 | 5.12 | 3.17 | 5.30 | 4.59 | 5.12 | 4.97 | 5.52 |
| 30 | 5.33 | 5.68 | 5.47 | 3.41 | 5.52 | 4.67 | 5.25 | 5.15 | 5.55 |
| 31 | 5.56 | 6.02 | 5.58 | 3.50 | 5.83 | 4.71 | 5.42 | 5.26 | 5.67 |
| 32 | 5.78 | 6.14 | 5.87 | 3.77 | 5.87 | 4.98 | 5.45 | 5.40 | 5.68 |
| 33 | 5.94 | 6.23 | 5.98 | 3.84 | 5.89 | 5.07 | 5.73 | 5.60 | 5.80 |
| 34 | 5.95 | 6.29 | 6.18 | 4.17 | 6.02 | 5.09 | 5.82 | 5.92 | 6.21 |
| 35 | 6.37 | 6.37 | 6.90 | 4.42 | 6.05 | 5.14 | 5.95 | 5.93 | 6.40 |
| 36 | 6.82 | 6.69 | 7.31 | 4.44 | 6.07 | 5.25 | 5.96 | 6.30 | 6.98 |
| 37 | 7.10 | 7.00 | 7.44 | 4.52 | 6.49 | 5.29 | 6.50 | 6.50 | 7.61 |
| 38 | 7.36 | 7.10 | 7.62 | 4.61 | 6.78 | 5.63 | 6.62 | 6.52 | 8.00 |
| 39 | 7.54 | 7.11 | 7.69 | 4.76 | 7.03 | 5.68 | 6.64 | 6.76 | 8.57 |
| 40 | 7.86 | 7.27 | 7.83 | 4.90 | 7.18 | 5.90 | 7.24 | 6.87 | 8.62 |
| 41 | 8.46 | 7.40 | 7.87 | 5.51 | 7.47 | 6.46 | 7.45 | 6.91 | 8.90 |
| 42 | 8.48 | 8.68 | 7.90 | 5.63 | 7.79 | 6.62 | 7.66 | 7.05 | 9.37 |
| 43 | 8.92 | 8.97 | 7.91 | 5.68 | 8.08 | 6.95 | 7.73 | 7.07 | 9.53 |
| 44 | 9.08 | 9.31 | 8.04 | 6.07 | 8.12 | 7.24 | 7.96 | 7.46 | 9.69 |
| 45 | 9.57 | 9.97 | 8.70 | 6.73 | 8.78 | 7.76 | 8.00 | 10.26 | 10.08 |
| 46 | 10.17 | 10.39 | 9.57 | 7.37 | 9.37 | 7.91 | 8.34 | 10.58 | 10.36 |
| 47 | 10.57 | 10.86 | 12.88 | 8.02 | 10.80 | 8.05 | 8.65 | 10.88 | 10.37 |
| 48 | 10.68 | 11.20 | 12.88 | 8.35 | 10.83 | 8.41 | 9.64 | 11.35 | 10.45 |
| 49 | 11.17 | 11.66 | 12.88 | 16.39 | 16.19 | 8.52 | 15.48 | 12.36 | 10.77 |
| 50 | 11.51 | 12.13 | 12.88 | 16.39 | 16.19 | 10.42 | 15.48 | 20.01 | 11.45 |
| 51 | 13.17 | 19.61 | 12.88 | 16.39 | 16.19 | 10.88 | 15.48 | 20.01 | 11.83 |
| 52 | 15.91 | 19.61 | | 16.39 | 16.19 | 12.02 | 15.48 | 20.01 | 17.18 |
| 53 | 15.91 | 19.61 | | 16.39 | 16.19 | 13.37 | 15.48 | 20.01 | 17.18 |
| 54 | 15.91 | 19.61 | | 16.39 | 16.19 | 13.37 | 15.48 | 20.01 | 17.18 |
| 55 | 15.91 | 19.61 | | | | 13.37 | | 20.01 | 17.18 |
| 56 | 15.91 | 19.61 | | | | 13.37 | | | 17.18 |
| 57 | 15.91 | | | | | 13.37 | | | 17.18 |
| 58 | | | | | | 13.37 | | | |
| | | | | | | | | | |
| Average - Upper bound adjustment to calc'd 90th percentiles | 6.51 | 6.87 | 5.22 | 4.46 | 5.75 | 5.23 | 5.71 | 6.37 | 6.58 |
| Average (All Data) | 6.51 | 6.87 | 5.22 | 4.46 | 5.75 | 5.23 | 5.71 | 6.37 | 6.58 |
| Delta (Staff - All Data) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 90th Percentile per Staff | 13.41 | 13.09 | 9.57 | 9.10 | 11.11 | 12.17 | 10.17 | 12.41 | 12.67 |
| Upper bound to preserve mea | 15.91 | 19.61 | 12.88 | 16.39 | 16.19 | 13.37 | 15.48 | 20.01 | 17.18 |

| 1999-2002 Data | Replace extreme w/ 90/10 percentiles | Adj Upper Bound |
|---|---|---|
| 0.00 | 1.10 | 1.10 |
| 0.01 | 1.10 | 1.10 |
| 0.09 | 1.10 | 1.10 |
| 0.33 | 1.10 | 1.10 |
| 0.54 | 1.10 | 1.10 |
| 0.60 | 1.10 | 1.10 |
| 0.63 | 1.10 | 1.10 |
| 0.64 | 1.10 | 1.10 |
| 0.69 | 1.10 | 1.10 |
| 0.70 | 1.10 | 1.10 |
| 0.72 | 1.10 | 1.10 |
| 0.79 | 1.10 | 1.10 |
| 0.83 | 1.10 | 1.10 |
| 0.88 | 1.10 | 1.10 |
| 0.91 | 1.10 | 1.10 |
| 0.92 | 1.10 | 1.10 |
| 0.94 | 1.10 | 1.10 |
| 0.98 | 1.10 | 1.10 |
| 0.99 | 1.10 | 1.10 |
| 1.00 | 1.10 | 1.10 |
| 1.00 | 1.10 | 1.10 |
| 1.06 | 1.10 | 1.10 |
| 1.12 | 1.12 | 1.12 |
| 1.14 | 1.14 | 1.14 |
| 1.21 | 1.21 | 1.21 |
| 1.21 | 1.21 | 1.21 |
| 1.26 | 1.26 | 1.26 |
| 1.30 | 1.30 | 1.30 |
| 1.33 | 1.33 | 1.33 |
| 1.37 | 1.37 | 1.37 |
| 1.40 | 1.40 | 1.40 |
| 1.42 | 1.42 | 1.42 |
| 1.55 | 1.55 | 1.55 |
| 1.59 | 1.59 | 1.59 |
| 1.62 | 1.62 | 1.62 |
| 1.64 | 1.64 | 1.64 |
| 1.67 | 1.67 | 1.67 |
| 1.70 | 1.70 | 1.70 |
| 1.72 | 1.72 | 1.72 |
| 1.77 | 1.77 | 1.77 |
| 1.81 | 1.81 | 1.81 |
| 1.86 | 1.86 | 1.86 |
| 1.89 | 1.89 | 1.89 |
| 1.90 | 1.90 | 1.90 |
| 1.91 | 1.91 | 1.91 |
| 1.92 | 1.92 | 1.92 |
| 1.94 | 1.94 | 1.94 |
| 1.97 | 1.97 | 1.97 |
| 1.99 | 1.99 | 1.99 |
| 2.00 | 2.00 | 2.00 |
| 2.04 | 2.04 | 2.04 |
| 2.04 | 2.04 | 2.04 |
| 2.10 | 2.10 | 2.10 |
| 2.15 | 2.15 | 2.15 |
| 2.15 | 2.15 | 2.15 |
| 2.19 | 2.19 | 2.19 |
| 2.37 | 2.37 | 2.37 |
| 2.42 | 2.42 | 2.42 |
| 2.46 | 2.46 | 2.46 |
| 2.49 | 2.49 | 2.49 |
| 2.50 | 2.50 | 2.50 |
| 2.53 | 2.53 | 2.53 |
| 2.54 | 2.54 | 2.54 |
| 2.56 | 2.56 | 2.56 |
| 2.57 | 2.57 | 2.57 |
| 2.60 | 2.60 | 2.60 |
| 2.68 | 2.68 | 2.68 |
| 2.70 | 2.70 | 2.70 |

| | |
|---|---|
| 11.51 | 90th Percentile |
| 1.102 | 10th Percentile |
| 5.79 | Mean - All Data |
| 5.25 | Mean - Replace outside 90th / 10th Percentiles (Staff Method) |
| 5.79 | Mean - w/adj to upper bound |

| PGE Suggested Calc of FOR benchmark: | |
|---|---|
| Lower Bound | 1.102 |
| Upper Bound | 17.12 |

| 1999-2002 Data | Replace extreme w/ 90/10 percentiles | | Adj Upper Bound |
|---|---|---|---|
| 2.77 | 2.77 | | 2.77 |
| 2.79 | 2.79 | | 2.79 |
| 2.81 | 2.81 | | 2.81 |
| 2.92 | 2.92 | | 2.92 |
| 2.99 | 2.99 | | 2.99 |
| 2.99 | 2.99 | | 2.99 |
| 3.03 | 3.03 | | 3.03 |
| 3.06 | 3.06 | | 3.06 |
| 3.10 | 3.10 | | 3.10 |
| 3.11 | 3.11 | | 3.11 |
| 3.12 | 3.12 | | 3.12 |
| 3.17 | 3.17 | | 3.17 |
| 3.22 | 3.22 | | 3.22 |
| 3.25 | 3.25 | | 3.25 |
| 3.25 | 3.25 | | 3.25 |
| 3.35 | 3.35 | | 3.35 |
| 3.41 | 3.41 | | 3.41 |
| 3.47 | 3.47 | | 3.47 |
| 3.50 | 3.50 | | 3.50 |
| 3.71 | 3.71 | | 3.71 |
| 3.77 | 3.77 | | 3.77 |
| 3.84 | 3.84 | | 3.84 |
| 3.84 | 3.84 | | 3.84 |
| 3.89 | 3.89 | | 3.89 |
| 3.93 | 3.93 | | 3.93 |
| 4.01 | 4.01 | | 4.01 |
| 4.02 | 4.02 | | 4.02 |
| 4.17 | 4.17 | | 4.17 |
| 4.18 | 4.18 | | 4.18 |
| 4.22 | 4.22 | | 4.22 |
| 4.26 | 4.26 | | 4.26 |
| 4.33 | 4.33 | | 4.33 |
| 4.34 | 4.34 | | 4.34 |
| 4.37 | 4.37 | | 4.37 |
| 4.42 | 4.42 | | 4.42 |
| 4.44 | 4.44 | | 4.44 |
| 4.50 | 4.50 | | 4.50 |
| 4.51 | 4.51 | | 4.51 |
| 4.52 | 4.52 | | 4.52 |
| 4.56 | 4.56 | | 4.56 |
| 4.60 | 4.60 | | 4.60 |
| 4.61 | 4.61 | | 4.61 |
| 4.62 | 4.62 | | 4.62 |
| 4.68 | 4.68 | | 4.68 |
| 4.76 | 4.76 | | 4.76 |
| 4.78 | 4.78 | | 4.78 |
| 4.80 | 4.80 | | 4.80 |
| 4.89 | 4.89 | | 4.89 |
| 4.90 | 4.90 | | 4.90 |
| 4.90 | 4.90 | | 4.90 |
| 4.95 | 4.95 | | 4.95 |
| 4.98 | 4.98 | | 4.98 |
| 5.00 | 5.00 | | 5.00 |
| 5.05 | 5.05 | | 5.05 |
| 5.12 | 5.12 | | 5.12 |
| 5.14 | 5.14 | | 5.14 |
| 5.23 | 5.23 | | 5.23 |
| 5.32 | 5.32 | | 5.32 |
| 5.33 | 5.33 | | 5.33 |
| 5.47 | 5.47 | | 5.47 |
| 5.51 | 5.51 | | 5.51 |
| 5.56 | 5.56 | | 5.56 |
| 5.58 | 5.58 | | 5.58 |
| 5.63 | 5.63 | | 5.63 |
| 5.67 | 5.67 | | 5.67 |
| 5.68 | 5.68 | | 5.68 |
| 5.68 | 5.68 | | 5.68 |
| 5.78 | 5.78 | | 5.78 |

| 1999-2002 Data | Replace extreme w/ 90/10 percentiles | | Adj Upper Bound |
|---|---|---|---|
| 5.87 | 5.87 | | 5.87 |
| 5.94 | 5.94 | | 5.94 |
| 5.95 | 5.95 | | 5.95 |
| 5.98 | 5.98 | | 5.98 |
| 6.02 | 6.02 | | 6.02 |
| 6.07 | 6.07 | | 6.07 |
| 6.14 | 6.14 | | 6.14 |
| 6.18 | 6.18 | | 6.18 |
| 6.23 | 6.23 | | 6.23 |
| 6.29 | 6.29 | | 6.29 |
| 6.37 | 6.37 | | 6.37 |
| 6.37 | 6.37 | | 6.37 |
| 6.69 | 6.69 | | 6.69 |
| 6.73 | 6.73 | | 6.73 |
| 6.82 | 6.82 | | 6.82 |
| 6.90 | 6.90 | | 6.90 |
| 7.00 | 7.00 | | 7.00 |
| 7.10 | 7.10 | | 7.10 |
| 7.10 | 7.10 | | 7.10 |
| 7.11 | 7.11 | | 7.11 |
| 7.27 | 7.27 | | 7.27 |
| 7.31 | 7.31 | | 7.31 |
| 7.36 | 7.36 | | 7.36 |
| 7.37 | 7.37 | | 7.37 |
| 7.40 | 7.40 | | 7.40 |
| 7.44 | 7.44 | | 7.44 |
| 7.54 | 7.54 | | 7.54 |
| 7.62 | 7.62 | | 7.62 |
| 7.69 | 7.69 | | 7.69 |
| 7.83 | 7.83 | | 7.83 |
| 7.86 | 7.86 | | 7.86 |
| 7.87 | 7.87 | | 7.87 |
| 7.90 | 7.90 | | 7.90 |
| 7.91 | 7.91 | | 7.91 |
| 8.02 | 8.02 | | 8.02 |
| 8.04 | 8.04 | | 8.04 |
| 8.35 | 8.35 | | 8.35 |
| 8.46 | 8.46 | | 8.46 |
| 8.48 | 8.48 | | 8.48 |
| 8.68 | 8.68 | | 8.68 |
| 8.70 | 8.70 | | 8.70 |
| 8.92 | 8.92 | | 8.92 |
| 8.97 | 8.97 | | 8.97 |
| 9.08 | 9.08 | | 9.08 |
| 9.31 | 9.31 | | 9.31 |
| 9.42 | 9.42 | | 9.42 |
| 9.57 | 9.57 | | 9.57 |
| 9.57 | 9.57 | | 9.57 |
| 9.97 | 9.97 | | 9.97 |
| 10.17 | 10.17 | | 10.17 |
| 10.39 | 10.39 | | 10.39 |
| 10.51 | 10.51 | | 10.51 |
| 10.57 | 10.57 | | 10.57 |
| 10.68 | 10.68 | | 10.68 |
| 10.68 | 10.68 | | 10.68 |
| 10.71 | 10.71 | | 10.71 |
| 10.86 | 10.86 | | 10.86 |
| 11.17 | 11.17 | | 11.17 |
| 11.20 | 11.20 | | 11.20 |
| 11.51 | 11.51 | | 11.51 |
| 11.51 | 11.51 | | 11.51 |
| 11.66 | 11.51 | | 17.12 |
| 12.03 | 11.51 | | 17.12 |
| 12.13 | 11.51 | | 17.12 |
| 13.17 | 11.51 | | 17.12 |
| 13.78 | 11.51 | | 17.12 |
| 13.97 | 11.51 | | 17.12 |
| 14.02 | 11.51 | | 17.12 |

| 1999-2002 Data | Replace extreme w/ 90/10 percentiles | | Adj Upper Bound |
|---|---|---|---|
| 14.05 | 11.51 | | 17.12 |
| 14.22 | 11.51 | | 17.12 |
| 14.38 | 11.51 | | 17.12 |
| 14.48 | 11.51 | | 17.12 |
| 16.71 | 11.51 | | 17.12 |
| 17.06 | 11.51 | | 17.12 |
| 17.74 | 11.51 | | 17.12 |
| 17.86 | 11.51 | | 17.12 |
| 18.34 | 11.51 | | 17.12 |
| 19.24 | 11.51 | | 17.12 |
| 20.55 | 11.51 | | 17.12 |
| 23.00 | 11.51 | | 17.12 |
| 34.51 | 11.51 | | 17.12 |
| 36.55 | 11.51 | | 17.12 |

January 7, 2009

TO: Gordon Feighner
Citizens' Utility Board

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

**PORTLAND GENERAL ELECTRIC**
**UM 1355**
**PGE Response to CUB Data Request**
**Dated January 6, 2009**
**Question No. 001**

**Request:**

**Please provide to CUB complete copies of any and all information previously provided to Staff in response to Staff's informal data requests.**

*Response:*

Attachment 001-A is PGE's actual and forecasted planned maintenance hours for our thermal plants from 2002 through 2008. We provided this information to OPUC Staff as an informal data response by email on November 10, 2008.

# UM 1355
# Attachment 001-A

Actual vs. Forecasted Planned Maintenance Hours

**UM 1355 Investigation into Forced Outage Rate**
**PGE Thermal Plants**
**Forecasted and Actual Planned Maintenance Outages**

| | | | Duration is in Number of Days | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Boardman | | Colstrip Unit 3 | | Colstrip Unit 4 | | Coyote Springs - All States | | Port Westward | |
| | Forecasted* | Actual | Forecasted | Actual | Forecasted | Actual | Forecasted | Actual | Forecasted | Actual | Forecasted | Actual |
| UE 192 | 2008 AUT | 2008 | 30 | 30 | 0 | 0 | 0 | 0 | 9 | 8 | 16 | 8 |
| UE 180 | GRC, 2007 Test Year | 2007 | 30 | 26 | 44 | 49 | 0 | 0 | 20 | 17 | 16 | 12 |
| UE 172 | 2006 RVM | 2006 | 29 | 0 | 9 | 0 | 52 | 52 | 16 | 11 | na | na |
| UE 161 | 2005 RVM | 2005 | 32 | 29 | 7 | 0 | 7 | 0 | 9 | 15 | na | na |
| UE 149 | 2004 RVM | 2004 | 69 | 72 | 44 | 59 | 0 | 0 | 0 | 4 | na | na |
| UE 139 | 2003 RVM | 2003 | 30 | 29 | 0 | 0 | 58 | 56 | 28 | 35 | na | na |
| UE 115 | GRC, 2002 Test Year | 2002 | 16 | 30 | 15 | 0 | 30 | 0 | 9 | 5 | na | na |

* Forecasted data are from Monet PC Input Sheets related to each UE Docket Number and/or final Assumptions/Summary Report.

Comment: The Boardman actual value of zero in 2006 is the year the major forced outage extended into June, so there was no actual scheduled outage this year.

# PGE's Reference List

| | UM 1355 Consolidated Issues List | Direct Testimony | Reply Testimony |
|---|---|---|---|
| **I.** | **What forecasting methodology should the Commission adopt for thermal generating plants?** | Sections III and IV | |
| | a. Should there be a different forecasting method for peaker plant versus base load plant?<br>i. Are there any particular considerations (e.g. combined cycle plant outage rate computations)? | | Section II.A |
| | b. Which forced outages should be included in the forced outage rate determination (e.g. extreme events)?<br>i. What role should industry data play in this determination? | Section IV.A.3 | Section III |
| | c. What methodology should be employed for treatment of excluded outages? | | Section III.A.3 |
| | d. What is the appropriate methodology for calculating forced outage rates and how should that be applied within the power cost model? | | Section III.A.1 |
| | e. How should new thermal resources be treated? | Section IV.A.4 | |
| | f. What is the appropriate length for the historical period? | Section IV.A.2 | |
| | g. Should non-outage related adjustments be included in the forced outage rate determination? If so, which non-outage related adjustments should be included? | | |
| | h. Should the forced outage rate determination be adjusted when a new capital investment improves reliability | | |
| **II.** | **What hydro availability methodology should the Commission adopt?** | Section IV.B | |
| **III.** | **What wind availability reporting methodology should the Commission adopt?** | Section IV.C | Section III.A |
| | a. How should wind availability be appropriately applied to forecasting for a rate determination? | Section IV.C | |
| **IV.** | **What methodology should the Commission adopt for planned maintenance (e.g. average versus forecast) of thermal, hydro, and wind plants?** | Section IV.D | Section II.B |
| | a. How should this methodology be applied (e.g. high load/low load split, weekend/weekday split)? | | Section II.C |
| **V.** | **What data reporting requirements should the Commission require regarding outages?** | Section V | Section III.B |

# Minimum Filing Requirements
# July 7, 2008

## General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

## Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

# Direct Case Filing

Applicability
- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents
1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

<u>Supporting Documents and Work Papers for the Following</u>

7. Forward Curve Inputs. Consists of:
    a. Electric curve extract from Trading Floor curve file
    b. Gas curve extract from Trading Floor curve file
    c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
    d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
    e. Oil forward curve
8. Load Inputs. Consists of:
    a. Monthly load forecast from Load Forecast Group
    b. Hourly load forecast from Load Forecast Group
    c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
    a. Capacities
    b. Heat Rates
    c. Variable O&M

        This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, $SO_2$ emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
    d. Forced outage rates
    e. Maintenance outage schedules and derations
    f. Minimum capacities
    g. Operating constraints
    h. Minimum up times
    i. Minimum down times
    j. Plant testing requirements
    k. Oil usage volumes
    l. Coal commodity costs
    m. Coal transportation costs
    n. Coal fixed fuel costs classified as NVPC items

        Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

        This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

        For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

        Electric Physical Contracts
        Electric Financial Contracts
        Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

<u>Historical Operating Data</u>

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

## Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

prices. While inclusion of outages in test year assumptions for four years after occurrence may provide an opportunity to recover some losses, full cost recovery is far from certain. The utility also typically incurs higher O&M costs, working to repair whatever has caused the outage.

**Q. Does ICNU offer any examples of utilities showing lower concern for plant reliability because their prices reflect, one way or another, historical forced outage rates they experience for their generating plants?**

A. No.

**Q. Do either Staff or ICNU make any demonstration that using NERC data, stochastically or not, will produce test year forced outage rate assumptions that are more accurate than the rolling four-year average methodology?**

A. No. They provide no such demonstration either for 2007 or for any particular series of years.

**Q. Is there a clear best way to select peer groups from within the NERC data?**

A. No. There are many ways to parse the NERC data, not simply by size and fuel type.

**Q. How do Staff and ICNU select peer groups?**

A. They both use NERC data that is classified only by size of plant and fuel type, e.g., 600-799 MW and coal for Colstrip.

**Q. Does NERC recommend using data in this way?**

A. No. NERC itself offers a benchmarking service, and in its material criticizes the approach Staff and ICNU chose. PGE Exhibit 1912 is a copy of NERC material on its benchmarking service. It states that

> "many benchmarking programs have assumed that for fossil steam units, fuel type and size ranges are the proper selection criteria. We have

> found from our extensive benchmarking studies that fuel types and especially the arbitrary size ranges (100-199 MW, 200-299 MW, etc.) are relatively much less statistically significant than other design and operational characteristics such as criticality, duty cycle, vintage, pressurized/balanced draft, etc. Because each individual unit is unique, our process ensures that the optimal peer group is selected; balancing the need for similarity in design and operations with the need for a large enough sample size for statistical validity. Without this objective analysis to find the optimal peer select criteria any conclusions drawn from the comparisons could very well be invalid and misleading."

Ironically, Staff cites this document (Staff/100, Gaalbraith/18, footnote 5) but disregards NERC's advice in choosing peer groups.

**Q. Are there other potential issues with the use of NERC data?**

A. Yes. Utilities report to NERC voluntarily; nothing requires this reporting. Also, data reporting may not be consistent across all utilities. For example, one plant's forced outage may be another plant's maintenance outage.

**Q. Did Staff recognize this potential issue?**

A. Yes. Staff recognized this (Staff/100, Galbraith /11-12) and suggests adjusting NERC forced outage rates.

**Q. Please explain.**

A. PGE adjusts forced outages as reported by the individual generating plants to included forced maintenance outages. That is, the plant may report an outage as a maintenance outage if the plant was able to delay the outage for a short period of time. However this outage is properly classified as a forced outage, and reflected as such in our RVM filings.

Staff's solution to the forced/maintenance outage issue with NERC data is to apply an adjustment equal to the percentage difference between PGE's forced outage rate as reported by the plant and that used for RVM filings. This adjustment is 7.26

percent and 7.69 percent for Boardman and Colstrip respectively. The major problem with Staff's solution is the reliance on the untested assumption that other utilities have the same correlation between forced outages and forced maintenance outages as reported to NERC.

**Q. Has Staff used NERC data in the past?**

A. Yes. In the 1984 memo NERC data was incorporated only when there was insufficient plant data. Further, the analysis focused on vintage, in addition to capacity and fuel type.

**Q. Do you agree with ICNU's assertion that the NERC data provide an "objective, verifiable means of estimating power costs?" (ICNU/103, Falkenberg/15).**

A. No. As we noted above, reporting is voluntary and even Staff recognizes that reporting utilities may not do so using consistent definitions. While NERC data may be fine for general comparisons, it is not appropriate for ratemaking purposes.

**Q. What adjustments to 2007 test year forecasted NVPC do Staff and ICNU propose based on this change in methodology?**

A. Staff recommends reducing PGE's 2007 test year forecasted NVPC by $12.847 million. ICNU recommends a reduction of $7.175 million.

**Q. Could you verify the calculations ICNU made to produce the suggested reduction to the 2007 test year NVPC forecast?**

A. No. The capacities of Boardman and Colstrip shown in ICNU's analysis were incorrect, listed as 383 and 294.8 when actual capacities are 380.25 and 293.6 respectively for the 2007 test year. Also, we could not verify the NERC forced

(Staff/100, Galbraith/7). There is also an interplay with any PCA mechanism. A sharing regime mitigates problems associated with forced outage assumptions; a deadband can be more problematic.

**Q. Are there other issues with parties' positions on removing the 2005 Boardman outage, and Colstrip for all of 2002?**

A. Yes. First, regarding Boardman, UM 1234 is addressing the 2005-2006 outage. We expect guidance from the Commission regarding treatment for the portion of this outage during the deferral period, which should also inform us on how to derive the four-year average for this docket.

Second, regarding Colstrip, there has been no evidence presented on imprudence, either in this case, or the 2004, 2005, or 2006 RVM proceedings, or in PacifiCorp's recently completed rate case. As stated above, the only rationale is that it is an "extreme outage rate." If this is indeed a proper standard, fairness would require removal of years when plants perform exceptionally well. Coyote had such exceptional performance in 2002, 2004 and 2005 with forced outage rates of 1.6, 0.76, and 1.01 percent, respectively. Parties are not clamoring for removal of these exceptional outage rates. Inclusion of only exceptionally good years is asymmetric treatment, and improper.

**Q. What is Staff's response to your concerns with its choice of peer groups for Boardman and Colstrip?**

A. Staff disregards our concern that NERC itself is critical of the method Staff and ICNU used in choosing peer groups for plant comparisons. Staff states that, from its review of the NERC benchmarking,

> The material describing these benchmarking services does not indicate the sign or magnitude of the potential bias. (Staff/1500, Galbraith/19, lines 14-16)

Staff does not deny that bias exists.

**Q. Staff suggests the optimal peer group may have a lower forced outage rate than its chosen peer group, "in other words, the optimal peer group for the Boardman unit may have a lower forced outage rate than the standard peer group based on fuel type and capacity." (Staff/1500, Galbraith/19, lines 17-19). Is this proper justification for selecting a peer group?**

A. No. This is just speculation. The optimal peer group could have a higher, or lower, forced outage rate. Conceivably the optimal peer group's rate could equal the overall average.

**Q. Staff calls the NERC data "verifiable and objective." (Staff/1500, Galbraith/19, line 24). Is this correct?**

A. This does not appear to be true. PGE could not verify ICNU's NERC data. (PGE Exhibit/1900, Tinker-Schue-Drennan/44). Further, ICNU could not explain the differences in their data and those that PGE found on the NERC website. ICNU states:

> It is possible that NERC may have retroactively revised its figures after I obtained these documents from its web page. (ICNU/108, Falkenberg/18, lines 18-20)

ICNU rationalizes away the differences stating:

> "it makes little difference, because the numbers differ by only a small amount." (ICNU/108, Falkenberg/18, lines 20-21)

Similar to Staff's 'defense' of peer group choice, ICNU's defense seems weak.

**Q. Do you have any other issues with the contention of 'verifiable and objective' data?**

A. Yes. As shown above we could not verify the data on a macro level. We are also unaware how one would verify the data on a plant-specific level. PGE is doubtful that we, or any other party, could verify that the data included in the NERC dataset are correct, especially when such data involve plants outside of our control.

It may be that the data are "objective" from the NERC standpoint, *i.e.*, NERC probably has no stake in presenting the data figures in one way or another. On a plant-specific level, there may be issues of objectivity. As stated in our testimony (PGE Exhibit/1900, Tinker-Schue-Drennan/43), plants may not report outages in the same manner.

**Q. The current method of forecasting forced outage rates is well established, having been in place for more than 20 years. If the Commission decides it would like to change methodologies, what should it consider?**

A. Any change should be well reasoned, not based on a single occurrence. (Staff/1500, Galbraith/19). Any change should include all utilities, not strictly PGE. Any change should include all units, not a subset of units (unless there are appropriate reasons). Any change, if using NERC data, should rely on the appropriate peer group, not an overall average that may or may not be reflective of the generating unit in question.

**Q. How should the Commission proceed with any changes to the current forced outage methodology?**

A. One possibility is to open an investigation so that all utilities and stakeholders could participate. This investigation would focus on alternatives to the current methodology, such as use of NERC data. If the investigation shows more accurate or more appropriate alternatives, the Commission should consider changes to its current policy.

**Q. How did Staff and ICNU misconstrue PGE's statements regarding forced and planned outages?**

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day caused **PGE REPLY TESTIMONY** 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. 1355

Dated at Portland, Oregon, this 13th day of May, 2009.

DOUGLAS C. TINGEY

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