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Douglas C. Tingey
Assistant General Counsel

April 7, 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:

- **Direct Testimony and Exhibits of Patrick G. Hager and Jay Tinker – PGE Exhibits 100 through 104. PGE Exhibits 103C and 104C are confidential and subject to protective order 08-549 and sent under separate cover. These confidential exhibits will not be posted on the OPUC website.**

Also enclosed are an original and three copies of:

- **Work Papers**

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.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT:smc
Enclosures
cc: Service List-UM 1355

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **DIRECT TESTIMONY AND EXHIBITS OF PORTLAND GENERAL ELECTRIC COMPANY (PGE 100-104C)** 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 7th day of April, 2009.

DOUGLAS C. TINGEY

SERVICE LIST

OPUC DOCKET # UM 1355

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I. Introduction

Q. Please state your names and positions with PGE.

A. 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.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. We present and explain PGE's proposed methodology for forecasting forced outage rates for generating plants. We also discuss the soundness of Staff's 1984 memo for determining the regulated FORs and why the methodology is still relevant today. We then present our position on each of the consolidated issues.

Q. How is your testimony organized?

A. In Section II, we discuss the purpose of the investigation into FORs as prescribed in Commission Order 07-015 and what transpired in the workshops in this docket.

In Section III, we summarize our position on the four-year rolling average and discuss the 1984 Staff memo. Then, we briefly discuss the power cost adjustment and deferral mechanisms.

In Section IV, we discuss our position on the consolidate issues in this docket.

In Section V, we provide our qualifications.

II. Investigation into Forecasting Forced Outage Rates

Q. What is the purpose of this investigation?

A. In Order 07-015, the Commission said they appreciated the concerns of the parties that a four-year rolling average (4YRA) of the forced outage rate (FOR) may not always be the most accurate forecast. For this reason, the Commission opened a new generic docket to examine this issue.

The Commission also recognized that there was an extreme outage at Boardman in 2005, and to account for that anomaly, they adjusted the 4YRA by removing the forced outage hours and period hours (November 18, 2005 through December 31, 2005) from the calculation. This adjustment was similar to the adjustment made in the PacifiCorp rate case for the extreme outage at the Hunter facilities.

Q. Does PGE agree with this direction set forth in the Order?

A. Yes. As we discuss in the next section, the 4YRA may not be a perfect estimate, but it's reasonable, easy to use, easily verifiable, and adjustments for extreme one-time events can easily be made to the methodology.

Q. Did the parties in this docket hold workshops?

A. Yes. Parties held four workshops on March 18, 2008, October 22, 2008, December 3, 2008, and January 14, 2009. During the workshops, we discussed FORs and planned maintenance outages (PMO) of not only thermal units, but also wind and hydro units. We also discussed details related to the calculation of the FOR of generating units. Based on the workshops, Staff assembled an issues list that was augmented by parties.

Q. What approach did PGE take in the workshops?

A. PGE believes the best approach is to determine what principles underlie the current FOR methodology used in rate making as well as what goals have guided FOR forecasting methodology. We believe the principles and goals are a prerequisite to a productive discussion as they relate to the current issues.

Q. Should the goal of accuracy and precision be desirable FOR forecast qualities?

A. Yes. Good forecasting practices lead to more accurate and precise estimates that are necessary for sound rate-making because they ensure that costs are effectively allocated to the customers who enjoy or influence the results of system operations. However, this goal must be balanced with the availability of data for the plants. Thus, complex models that rely on thermal plant data essentially provide a more precise, but not necessarily accurate forecast.

Q. Did the scope of the issues narrow during the workshops?

A. No. Forced outage rates for generating units is a broad issue. It is challenging to narrow the issues when the goal and principles are not well defined and agreed upon initially. Rather than narrowing the issues in the workshops, the issues have expanded significantly and we believe some parties seek a "one size fits all" approach as a proposed solution – trying to cover many one-time or abnormal situations.

Q. During the workshops did parties develop a better methodology than the 4YRA?

A. No. Although parties covered a variety of issues related to forecasting methodology for generating units, including thermal, wind and hydro facilities, and the workshops were productive, a better methodology than the 4YRA was not developed.

Q. Would PGE agree that the best approach to mitigating high replacement power costs due to high market prices is to solely change the 4YRA methodology in forecasting FORs?

A. No. Changing market prices are not reason enough to replace the 4YRA methodology with a different and unproven methodology. The 4YRA is one statistical aspect of plant performance in the model that incorporates many variables to forecast net variable power costs for rate-making purposes. High market prices increase the consequences of problems with any methodology.

A new unproven methodology could have problems affected by high market prices to a greater extent than any problems in the current methodology. Further, a new methodology may not result in the "…most accurate forecast of forced outages at the relevant plants," as directed by the Commission.

Q. What did PGE conclude from the workshops?

A. We believe the 4YRA has withstood the test of time. No one has demonstrated a superior methodology. The 4YRA is a uniform and simple methodology that works reasonably well, yet it's not a "one-size fits all" approach, and complements the Commission's other regulatory mechanisms such as the Power Cost Adjustment Mechanism (PCAM) and use of deferred accounting. We believe the 1984 Staff memo continues to be an appropriate framework with a clearly stated purpose and guidelines.

III. Forecasting Forced Outage Rates for Rate-Making Purposes

Q. Please summarize PGE's position.

A. PGE proposes that the Commission continue to use a 4YRA methodology for the following reasons:

- The 4YRA works well and is flexible enough for specific adjustments, as necessary.
- This methodology complements other regulatory mechanisms.
- The regulatory mechanisms work in concert to promote the goal of seeking "…the most accurate forecast of forced outage at the relevant plants."
- The methodology in the 1984 Staff memo is still relevant for the current issues in the docket.

A. 1984 Staff Memo

Q. Please briefly describe the 1984 Staff memo.

A. Since at least 1984, the Commission has allowed FORs to be forecast for rate-making, using the now familiar four-year average procedure. The 1984 Staff memo contains several basic guidelines and a clear purpose for forecasting the performance of thermal plants used in setting rates and the four year average methodology. PGE Exhibit 101 is the 1984 Staff memo.

Q. What was the purpose of the 1984 memo?

A. The memo was developed to provide uniform and "reasonable methods" for estimating thermal plant performance for rate setting.

Q. Is the purpose still relevant?

A. Yes. Although the Staff memo is almost 25 years old, its underlying guidelines remain relevant to the estimation of FORs.

Q. Are the guidelines still valid?

A. For the most part, yes. The memo prescribes definitions, formulas, methodology and analysis for thermal plant performance measures. However, the memo does not cover wind resources, since those resources are relatively new. Also, hydro plant performance was not discussed in the memo.

Q. Do the underlying principles and guidelines apply to wind and hydro resources?

A. Yes, the guidelines and principles of the Staff memo could also be applied to the non-thermal resources.

Q. Were any of the key points in the 1984 Staff memo discussed in the workshops?

A. Yes. The following points highlighted below are current issues we revisited in the workshops. As noted above, we find Staff's 1984 memo still provides relevant guidelines for the current issues.

- The purpose was to "…develop reasonable methods for calculating thermal plant performance levels to be used for calculating the cost of power." PGE believes the 4YRA remains a reasonable method for calculating and forecasting FORs for determining the cost of power in our financial model.
- "… using a 48-month calendar month rolling average is that it reflects recent plant experience, which tends to better portray expected operating over the coming year." In Order 07-015, the Commission adhered to the practice of using actual plant data outage rates to predict the future activity of plant. PGE also believes recent, plant specific data will produce a better indicator of future plant performance.

- "Four years of experience is sufficient to average out variations and yet not include generally irrelevant experience from history long past." PGE agrees that four years, more or less, is sufficient to average our variations of the rate. Section IV presents the Root Mean Squared Error of the FOR by year of PGE's Boardman and Colstrip plants.

Q. Is the 4YRA in the memo still useful for forecasting FORs?

A. Yes. The four-year average of actual plant experience provides a reasonable estimate of forecast outages because it is based on the plant's recent operating history and averages out yearly variation in experience.

B. PCAM and Deferral Mechanism

Q. Does PGE propose a deferral mechanism as a reasonable method to managing the power costs associated with a significant event?

A. Yes. In Docket No. UM 1234, Exhibit 100, PGE's Witness Pamela Lesh discussed the treatment of Boardman's FOR and the rate implications of the requested deferral. As Ms. Lesh stated, the deferral is one of the most versatile mechanisms in Oregon's regulatory framework and its uses are many and varied. "For PGE alone, uses over the last 20 years have ranged from deferring legal expenses and conservation program costs to revenues from property sales, cost under-runs in information technology expenditures, and tax rate reduction."

Without a deferral mechanism, PGE's only other option under Oregon's regulatory framework would be a request for a rate change that may not minimize the frequency of rate changes and fluctuations of rate levels. Deferring significant costs allows the Commission to design an amortization schedule that minimizes rate fluctuations and it affords an opportunity to review the utility's activity for prudence.

Q. Does the deferral mechanism provide the Commission with flexibility for making adjustments?

A. Yes. The deferral mechanism provides the Commission with the flexibility to make adjustments to the forced outage rate forecasts, when and, if needed.

Q. What purpose does the Power Cost Adjustment Mechanism (PCAM) serve in rate making associated with normal fluctuations experienced in forced outages?

A. The PCAM reduces the effects of unavoidable FOR forecast errors by accommodating random fluctuations normally experienced in forced outages. The PCAM compares PGE's actual unit net variable power costs (NVPC) with our Base Unit NVPC and multiplies the difference by actual load to determine an Annual Variance.

We then apply an asymmetrical power cost deadband to the Annual Variance followed by 90-10 sharing between customers and shareholders to develop the power cost variance. After this, we apply a symmetrical return on equity deadband to an earnings test to determine whether the final PCV should be collected from or refunded to customers.

Q. So, the current methodology of forecasting FOR fits well with the Commission's existing tools to handle variability in actual FORs experienced by generating units?

A. Yes. The 4YRA methodology is flexible and can be adjusted to accommodate deferred accounting for extreme events and provides a reasonable base to measure variations against for use with a PCAM.

IV. Consolidated Issues

Q. What are the consolidated issues submitted by parties?

A. On January 30, 2009, parties filed a consolidated issues list that consisted of five main issues, which are:

I. What forecasting methodology should the Commission adopt for thermal generating plants?

II. What hydro availability methodology should the Commission adopt?

III. What wind availability reporting method should the Commission adopt?

IV. What methodology should the Commission adopt for planned maintenance (e.g. average versus forecast) of thermal, hydro, and wind plants?

V. What data reporting requirements should the Commission require regarding outages?

For convenience, we attach a list of these issues as PGE Exhibit 102.

Q. Please summarize PGE's overall position on the Consolidated Issues.

A. PGE does not subscribe to the notion that there must be one method used by all utilities to calculate the FOR. There are too many variables to consider for each generating unit to apply a "one-size-fits-all" approach. We appreciate that the formulaic approach promotes convenience in reporting and analyzing plant data. But, we strongly believe that applying a generic formula to plant specific data would most likely result in less accuracy in estimating forced outages rates for regulatory purposes.

We believe that plant specific data should be used to forecast forced outages rates because this will provide the most accurate forecast. To the extent that changes must be made to the 4YRA to accommodate significant events it can be, and has been, done.

Q. What is PGE's position on each of the issues?

A. Below we discuss our position on many of the items in the consolidated issues list. We discuss how we treat forced outage rates and planned maintenance in Monet. We also discuss how we are currently treating wind availability and how we have traditionally treated hydro availability in Monet.

A. Issue I: Thermal Forecasting Methodology

Q. Please explain Issue I – forecasting methodology.

A. Issue I – what forecasting methodology should the Commission adopt for thermal generating units – is the most substantive issue and has many sub-issues, which are as follows:

- What is the appropriate methodology for calculating FOR?
- What is the appropriate length for the historical period?
- Which extreme events should be included in the FOR?
- Should there be a forecasting methodology for a peaker versus base load plant?
- How should new thermal resources be treated?
- Should the FOR be adjusted when a new capital investment improves reliability?
- Should non-outage related adjustments be included in the FOR?

1. Methodology

Q. Is the 4YRA an appropriate methodology?

A. Yes. The four year rolling average is, and has been, a reasonable methodology to forecast FORs as an input to the power cost model. A rolling average removes the volatility of the high and lows in the data, which is useful for a forecast and rate-making purposes, and it can be adjusted for extreme events without collapsing the underlying rolling-average methodology.

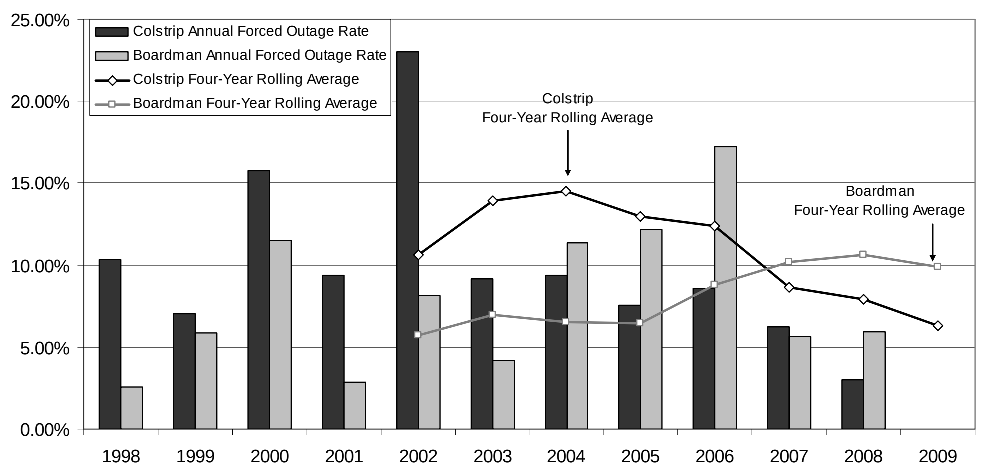
Q. Is a rolling-average normalized?

A. Yes. One purpose of a rolling average is to smooth out the highs and lows of the data, which essentially, normalizes the data. The benefit of a rolling average is that the average value is never as high as the peak and never as low as the trough.

Q. Please demonstrate how the 4YRA smoothes the high and lows?

A. Figure 1 below shows Boardman and Colstrip's annual versus the 4YRA FORs. The 4YRA trend line is smoother and is less volatile than an annual forced outage rate. For example, in 2002 Colstrip's annual FOR was about 23% and the 4YRA FOR was considerably lower at about 14%. Equally, in 2003, Colstrip's annual FOR was about 9%, whereas the 4YRA FOR was higher at about 15%. The smoothed 4YRA value is currently used in forecasting power cost, but adjusted for major outages, such as Boardman in 2005-2006.

Figure 1
Boardman and Colstrip Forced Outage Rates
Annual v. Four-Year Rolling Average



A four-year rolling average forced outage rate is based upon the previous four years historical data.
Therefore, the 2009 four-year rolling forced outage rate is based on historical data from 2005-2008.
Boardman's 2005 and 2006 forced outage rates s are adjusted per OPUC Order 07-015.

2. Length of Historical Period

Q. What length of historical period to forecast FORs is useful?

A. Four years of data are usually adequate to strike a reasonable balance between somewhat competing objectives and also encompass usual planned maintenance cycles and their effects, contributing a normalizing influence to the resulting forecast.

Q. Did you examine the use of rolling averages of differing lengths to forecast forced outage rates?

A. Yes. In order to see what length of forecast would tend to be more accurate, we examined rolling averages from one to six years. We calculated a forecast based on the number of time periods involved. For example, with a one-year rolling average last year's result were the prediction for the following year. With a two-year rolling average, years one and two would predict the outage rate for year three, and so forth.

Q. Please explain how you compared the accuracy of these differing forecasts.

A. We used the RMSE as our measure of forecast accuracy. The RMSE is calculated by taking the square root of the sum of squared errors divided by the number of observations. The errors in this case are the difference between the forecast and the actual observation.

Q. Do you have an example of this analysis for the Boardman plant?

A. Yes. We calculated the rolling average RMSE for the Boardman plant using data from 1998-2007.[1] Using this set of data, Figure 2 below shows the RMSE for the various rolling averages. As shown, the 4-year rolling average has the lowest RMSE at 5.19%. Boardman's plant data suggests that if we use less than three or more than four years of data for a rolling average in our forecasting methodology, the forecast would tend to be less accurate.

[1] 2005 and 2006 are adjusted FORs per OPUC Order 07-015.

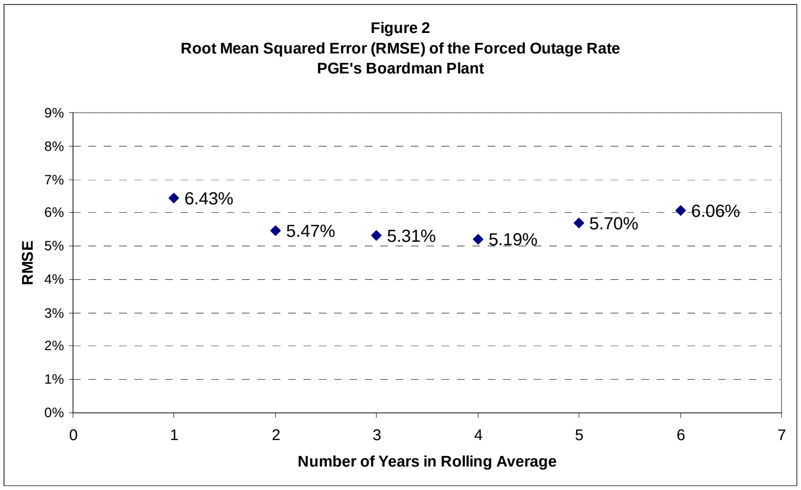


Figure 2
Root Mean Squared Error (RMSE) of the Forced Outage Rate
PGE's Boardman Plant

Q. What insight should we draw from the RMSE calculations?

A. The RMSE test the accuracy of the assumption that a 4-year rolling average produces the "most accurate forecast of forced outages at the relevant plants." The Boardman RMSE results meet our expectations. That is, the 3- and 4-year rolling average yielded the lowest error value. Colstrip provides similar results if an outlier is removed and are included in our papers. We have not calculated the RMSE for any of our other plants.

3. Extreme Events

Q. What types of extreme forced outages should be included (or excluded) in the FOR?

A. In Docket No. UM 1234, PGE Exhibit 400, pages 10-15 PGE Witnesses Lesh and Tinker discussed the Boardman outage as a significant enough event that qualified for deferral with material financial impact. Individual outage events that would be considered significant events should be treated outside the four-year average computation, as was done for the PGE Boardman outage and PacifiCorp's Hunter outage.

4. New Resources

Q. How was the FOR of a new gas plant, with no operational history, developed?

A. When Port Westward came on line in 2007, there was no operational history for calculating the FOR. Therefore, PGE looked at three sources for determining an appropriate rate for the first year of operation. Those three sources were 1) the "G" technology users' group, which is a group of owners and operators of similar type units utilizing similar technology; 2) the National Energy Reliability Council generating availability data system (NERC GADS); and 3) negotiations with the vendor.

The value from each source centers around nearly the same number. Although, we chose a slightly higher FOR supported by the understanding that most problems occur during a startup and the first year of operation will have a higher FOR compared to the following years of operation. Confidential Exhibit 103C is the Port Westward forced outage white paper.

Q. Should the methodology PGE applied to develop a forecast Port Westward's FOR be applied to all new plants?

A. Not necessarily. As we discussed earlier, there is no "one size files all" approach. For new facilities, each utility should attempt to gather relevant data on the plant or similar facilities to forecast FORs until enough operating data are available at the plant to develop FOR forecasts based on plant history.

5. Other Issues

Q. Are there issues not on the issue list that should be taken into consideration?

A. Yes. The 4YRA is a simple calculation, but the data collection and analysis processes behind determining the FOR requires substantial effort. For our thermal and hydro facilities, the raw data come from plant event logs. PGE spends time analyzing and classifying the hours because of the various operating states that exist for our various plants.

Q. Please describe the data collection process behind determining FORs for thermal pants.

A. Typically, the plant operates normally and without constraints. However, in some hours, the plant might be undergoing planned maintenance that was scheduled many months in advance. In other hours, a plant may be idled for economic reasons or the plant may be operating, but with limited power output because of a problem with a system component. Still other hours, a plant may be deliberately idled to fix a problem that had been observed at an earlier time. These various classifications of hours must be recorded by plant personal, and entered into the plant log.

Q. Please describe the analysis that is required to determine the thermal FOR.

A. PGE analysts check these records and notes for the Boardman and Colstrip plant to make sure that any errors in classification have been corrected and that any apparent conflicts in differing information sources are satisfactorily resolved. The analysis varies by plant. This process requires attention to detail, accuracy, and a considerable investment in time.

B. Issue II: Hydro Availability Methodology

Q. Please explain Issue II - hydro availability.

A. Issue II asks what hydro availability methodology should be adopted.

Q. How does PGE currently model hydro FORs in its Monet model?

A. With one minor exception[2], Monet does not model forced outages at hydro plants. This is based on the general assumption that most of the time, when a forced outage of a hydro unit

2 The minor exception is the Portland Hydro Project. The PHP is not regulated under the PNCA, and PGE uses an internal study from the early 1980s, updated a number of times since then, that uses historical stream flows and actual generation in its calculations, which therefore implicitly reflects a notion of actual maintenance and forced outage rate.

occurs, there is sufficient remaining capacity available from the other units at that hydro plant to generate as required to avoid incremental spill due to the forced outage. This is a modeling simplification, because there are times when hydro forced outages actually do cause incremental spill. However, we do not model this in Monet at this time. Confidential PGE Exhibit 104C provides a more detailed explanation of hydro modeling in Monet.

Q. How does PGE currently model hydro PMOs in its Monet model?

A. One of the steps in our study is to remove (zero out) any maintenance for the PGE hydro plants in the PNCA hydro regulation model. We then explicitly model in Monet any planned maintenance or related activities, such as test spills for fish, that we forecast to cause incremental spill. We model this using monthly deration factors. For example, if an entire hydro plant is forecasted to be out of service for three days in April, spilling its inflow during that time, we apply a 10% deration factor for that month. In most cases, routine hydro plant maintenance does not cause incremental spill, because usually maintenance is scheduled during low flow periods when adequate capacity is available from the other units at that plant to generate and thus avoid spill. There is generally no need to model PMOs of the Mid-Columbia (Mid-C) plants in Monet since they are included in the PNCA Headwater Benefits Study. However, for 2009, Monet does model lost energy due to incremental Mid-C spill caused by the Selective Water Withdrawal Structure testing at Round Butte, which will require the automatic generation control (AGC) function to be moved from Round Butte to the Mid-C during the testing period.

Q. Is there any significant reason to change the current methodology to model hydro in Monet?

A. No. The current methodology is appropriate and it works well. We believe the focus of this docket should be on the forced outage rate methodology.

C. Issue III: Wind Availability Methodology

Q. Please explain Issue III – wind availability.

A. Issue III asks, "What reporting method should be adopted and how should wind availability be appropriately applied to forecasting for rate determination."

Q. How does PGE currently model the FOR for the Biglow 1 Wind Farm in Monet?

A. For Biglow 1, we do not calculate a "separate" FOR in the Monet model in the same manner as our thermal plants. However, an availability factor based on a Garrad Hassan study is embedded in the capacity factor assumption in the Monet model.

Q. Does the Biglow 1 Wind Farm produce plant operating data?

A. Biglow's Supervisory Control and Data Acquisition (SCADA) system collects a variety of information about the wind turbines. We currently track operating hours, generation, and many other parameters, by tower when the system is communicating.[3] In addition, we do have a planned outage rate that is defined in our service agreement and a wind availability statistic is available. We presented Biglow's SCADA system to Staff, ICNU and CUB at the January 14, 2009 workshop.

D. Issue IV: Planned Maintenance of Thermal, Hydro, and Wind Plants

Q. Please explain issue IV – planned maintenance outage.

A. Issue IV states, "What methodology should the Commission adopt for planned maintenance, specifically average versus forecast, of thermal, hydro and wind plants." Furthermore, how should this methodology be applied? For example, is it useful to incorporate weekend or weekday splits of FORs?

[3] In 2008, we lost 20 percent of our tower data due to gophers eating the fiber optic cable. Lost fiber communications means that although the wind turbine may be generating power, the system's computer server is not recording actual operating data including individual tower generation and availability.

Q. How does PGE forecast FORs and PMOs on thermal plants in its Monet model?

A. In the Monet model, a thermal plant's monthly capacity is derated by the most recent 4YRA FOR and the forward-looking monthly maintenance factor. If a plant is expected to conduct a PMO for two weeks in April of the forecasted year, then the maintenance factor is 47% (14 days/30 days). Therefore, the monthly capacity value for the forecasted year is calculated as follows:

Plant Capacity in MW * (1-Monthly Maintenance Factor) * (1- 4YRA FOR)

Q. Are there any significant reasons as to why this methodology should change?

A. No. The current methodology is appropriate and it works well. Forecasting planned maintenance outages is much more straight-forward than forecasting an unknown such as a forced outage. With planned maintenance outages, we have a schedule for planned maintenances.

E. Issue V: What data reporting requirements should the Commission require regarding outages?

Q. Please explain Issue V – reporting requirements.

A. Issue V states, "What data reporting requirements should the Commission require regarding outages?"

Q. What FOR information does PGE file on a regular basis?

A. PGE expects to provide the FOR calculations, formulas, and supporting documentation in the Minimum Filing Requirements work papers of PGE's Annual Update Tariff filed on or before April 15, 2009. The Minimum Filing Requirements associated with net variable power costs include detailed descriptions of the inputs to the Monet model. The forced outage rate calculations have recently been provided in Docket Nos. UE 197 and UE 192.

Q. What information did PGE provide to OPUC Staff during the workshops?

A. We provided the FOR calculations, formulas, and plant event logs as well as PMO data for our Boardman and Colstrip plants.

V. Qualifications

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

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

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

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

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

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

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
Exhibit 101	1984 Staff Memo
Exhibit 102	Consolidated Issues List
Exhibit 103C	**Port Westward Forced Outage White Paper**
Exhibit 104C	**Hydro Modeling in Monet and Outage Rates**

CASE: UE 180/UE 181
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support of
Direct Testimony

July 18, 2006

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1859
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AUG - 1 1984

Earlier this year, we had extensive discussions concerning the performance of several thermal plants as used in setting rates. As a result of those discussions, Tom Harris has authored the attached memorandum stating staff's position on these matters.

For rate-making, we will use historical plant data to calculate the production available from each thermal plant. In general, we will use 48 calendar months, on a rolling basis, of unit performance data. Definitions and procedures are discussed in the attached memo.

As part of our ongoing rate-making process, we will need routine reports from each utility on the performance of thermal units. The PUC staff is attempting to treat thermal plants uniformly from plant to plant and company to company. The request for specific thermal plant data is directed to each utility as listed.

Idaho Power	-Valmy 1-2
Portland General Electric	-Trojan Boardman Colstrip 3-4
Pacific Power & Light	-Jim Bridger 1-4 Dave Johnston 1-4 Wyodak Centralia 1-2 Colstrip 3-4

Data Request

For Trojan, PGE is to continue providing staff with the monthly operating data report and the semiannual net electric generation graph.

For all the other plants, within 30 days after the end of each month, each company, as listed above, is to provide the PUC staff the following data for the preceding month for each thermal unit.

Month, Year
Plant and Unit Name
Maximum Dependable Capacity
Forced Outage Hours
Maintenance Outage Hours (Short Notice)
Planned Outage Hours (Annual Outage)
Reserve Shutdown Hours
Period Hours
Service Hours
*Equivalent Schedule Outage Hours ESOH
Equivalent Forced Outage Hours
Gross Generation--mwh
Net Generation--mwh
Planned Maintenance Schedule for Current and Subsequent Year

The above data is to be provided for the preceding month, year-to-date, preceding 12 calendar months, and 48 calendar months. Except for the last item in the list, all the other data is contained in the attached example Unit Data Summary report. Also, we wish to begin receiving the semiannual net electric generation graph for each plant as listed above for your company. In addition, you will note that performance data for Colstrip 3 depart from that used in the tracking filing. We propose using the technique suggested in Tom's memo for that facility in future rate reviews. Finally, Page 3 of Appendix A of the attached memo contains a reference to the North American Electric Reliability Council (NERC). We ask that each year each company foward the annual report from NERC containing such information immediately upon receipt.

Some additional specific questions regarding certain of the thermal plants will be transmitted in another letter.

If you have questions about this request, please contact Roger Colburn at 378-6894. Incidentally, Scott Girard has assumed responsibilities previously held by Tom Harris. His number is 378-6625.

WGWarren

William G. Warren
Manager
Energy Division

ger/05611

Attachments

cc: Roger Colburn
Scott Girard

DATE: 05/18/84

PACIFIC POWER & LIGHT COMPANY
UNIT DATA SUMMARY
PERIOD 5/ 1/83 THRU 4/30/84
WYODAK UNIT 1

FIRST SYNCHRONIZED 6/ 8/78 14:21 NAMEPLATE= 332MW DECLARED COMMERCIAL 9/18/78

		48 MONTH TOTAL		PERIOD		YEAR TO DATE		LAST MONTH	
FORCED	(HOURS/#)	712.10/	77	48.58/	3	5.28/	1	0.00/	0
MAINTENANCE	(HOURS/#)	29.95/	2	0.00/	0	0.00/	0	0.00/	0
PLANNED	(HOURS/#)	2649.38/	6	893.83/	2	0.00/	0	0.00/	0
RESERVE SHUTDOWN	(HOURS/#)	0.00/	0	0.00/	0	0.00/	0	0.00/	0
FORCED PARTIAL	(HOURS/#)	1999.37/ 2079.65	222	67.28/ 67.28	16	3.28/ 3.28	2	2.40/ 2.40	1
SCHEDULED PARTIAL	(HOURS/#)	127.12/ 127.12	16	0.00/ 0.00	0	0.00/ 0.00	0	0.00/ 0.00	0
~~NONCURTAILING EQUIPMENT~~	~~(HOURS/#)~~	~~64.42/~~	~~6~~	~~0.00/~~	~~0~~	~~0.00/~~	~~0~~	0.00/	0
PERIOD	(HOURS)	35064.00		8784.00		2904.00		720.00	
SERVICE	(HOURS)	31672.57		7841.58		2898.72		720.00	
AVAILABILITY	(HOURS)	31672.57		7841.58		2898.72		720.00	
EQUIVALENT SCHEDULED	(HOURS)	50.82		0.00		0.00		0.00	
EQUIVALENT FORCED	(HOURS)	335.70		14.58		0.56		0.45	
GROSS GENERATION	(MWH)	10230363.00		2512312.00		1044414.00		260368.00	
NET GENERATION	(MWH)	9270850.00		2283622.00		956340.00		237982.00	
MAX. DEPEND. CAP. GROSS	(MW)	345.00		345.00		345.00		345.00	
UNIT YEARS		4.00		1.00		0.33		0.08	

NOTE: EFFECTIVE SEPTEMBER 1,1977 THE UNIT MDC WAS CHANGED FROM 345 TO 345
PARTIAL OUTAGE DATA INCLUDES NONCONCURRENT (UPPER) AND CONCURRENT OUTAGE HOURS

CC: MCLAGAN,MORGAN,UDY,VINCENT,GENERATION ENGINEERING,POWER RESOURCES,THERMAL OPERATIONS

PUBLIC UTILITY COMMISSIONER OF OREGON
INTER-OFFICE CORRESPONDENCE

(NOT FOR MAILING)

Kelcey said she interpreted the memo to say a 4-year period encapsulates represents the cycles.

DATE: July 18, 1984

TO: Bill Warren

FROM: Tom Harris

SUBJECT: Thermal Plant Performance

INTRODUCTION

In this memo I shall summarize my investigation and analysis of the performance of thermal plants for use in our rate-making process. This memo represents a "final" wrap-up of the plant performance project I began in 1983. My purpose is to develop reasonable methods for calculating thermal plant performance levels to be used for calculating the cost of power.

Performance level includes both month-to-month availability of, or net megawatts available from, each plant and the length of the expected annual maintenance period. I intend to propose a method for calculating performance that can be applied uniformly from plant to plant and from company to company. There is an exception. I shall treat Trojan a little differently because PGE collects data for Trojan to meet NRC requirements, and such data differs from that collected for coal fired plants.

In general, I propose to use a 48-calendar month rolling average of historical performance for each thermal unit on which to base cost of power calculations. The megawatts available from each thermal unit are to be calculated by (1.0 - EOR) * (MW Net) for the months during the year the unit is scheduled to be available. Definitions for Equivalent Outage Rate (EOR), MW Net, Maximum Dependable Capacity (MDC), and other terms and procedures will be discussed later in this memo. EOR is to be calculated for a 48-month period for most thermal units. The reason I propose using a 48-calendar month rolling average is that it reflects recent plant experience, which I think tends to better portray expected operation over the coming year. Four years of experience is sufficient to average out variations and yet not include generally irrelevant experience from history long past.

DEFINITIONS

The definitions and procedures I am using are intended to be similar to those adopted by the Edison Electric Institute and the North American Electric Reliability Council. The differences I propose adopting were suggested by Pacific Power & Light and by Idaho Power Company.

Following I shall list and illustrate the formula and definitions to be used.

$$\text{MW available} = (1.0 - \text{EOR}) * (\text{MW Net})$$

$$\text{EOR} = \frac{\text{FOH} + \text{EFOH} + \text{MOH} + \text{ESOH}}{\text{SH} + \text{FOH} + \text{MOH}}$$

$$\text{MW Net} = \text{MDC} * \frac{\text{Net Generation mwh}}{\text{Gross Generation mwh}}$$

EA - Equivalent Availability - Includes effects of EOR and planned maintenance. Essentially equivalent to the percentage of time during which the unit was available for operation at full capability.

EOR - Equivalent Outage Rate - EOR categorizes and summarizes equipment failures and their corresponding outage periods. EOR characterizes the inability of a unit to operate when required for service. It essentially is equivalent to percentage of an anticipated service, during which a unit was not available for operation at full capability. Time required for planned outages and economy or reserve shutdowns is excluded when computing this index.

EFOH - Equivalent Forced Outage Hours - For a partial forced outage reduction, EFOH is equivalent time in hours for a full forced outage which would equal mwh lost because of the partial outage.

ESOH - Equivalent Scheduled Outage Hours - For a partial scheduled outage, ESOH is equivalent time in hours for a full scheduled outage which would equal mwh lost because of the partial outage.

Scheduled and maintenance outages are scheduled a relatively short time (i.e., few days) in advance. They are distinguished from planned outages which are planned months in advance (i.e., annual outages).

- Forced Outage - The occurrence of a component failure or other conditions which requires that the unit be removed from service immediately or up to and including the very next weekend.

- Forced Partial Outage - The occurrence of a component failure or other conditions which requires that the load on the unit be reduced two percent or more immediately or up to and including the very next weekend.

FOH - Forced Outage Hours - The time in hours during which a unit is unavailable due to a forced outage.

FPOH - Forced Partial Outage Hours - The time in hours during which a unit is unavailable for full load due to a forced partial outage.

MOH - Maintenance Outage Hours - The time in hours during which a unit is unavailable due to a maintenance outage.

A maintenance outage or scheduled outage is scheduled a relatively short time (i.e., few days) in advance. For our purposes, a maintenance outage is treated like a forced outage.

PH - Period Hours - Hours in the period under consideration, usually one month, one year, or four years.

POH - Planned Outage Hours - The time in hours a unit is unavailable due to a planned outage.

Planned outages are planned months in advance. Generally these are annual maintenance outages.

POR - Partial Outage Reduction - The size of reduction from MDC in megawatts during a partial outage.

RSH - Reserve Shutdown Hours - The time in hours a unit is shutdown for economy reasons.

SH - Service Hours - The total number of hours the unit was actually operated with breakers closed to the station bus.

SPOH - Scheduled Partial Outage Hours - The time in hours during which a unit is unavailable for full load due to a scheduled partial outage. Scheduled partial outages are generally scheduled a short time in advance. For our purposes, they are treated like a forced partial outage.

mw - Megawatts

MDC - Maximum Dependable Capacity - The dependable main-unit capacity, winter or summer, whichever is smaller. MDC includes station use.

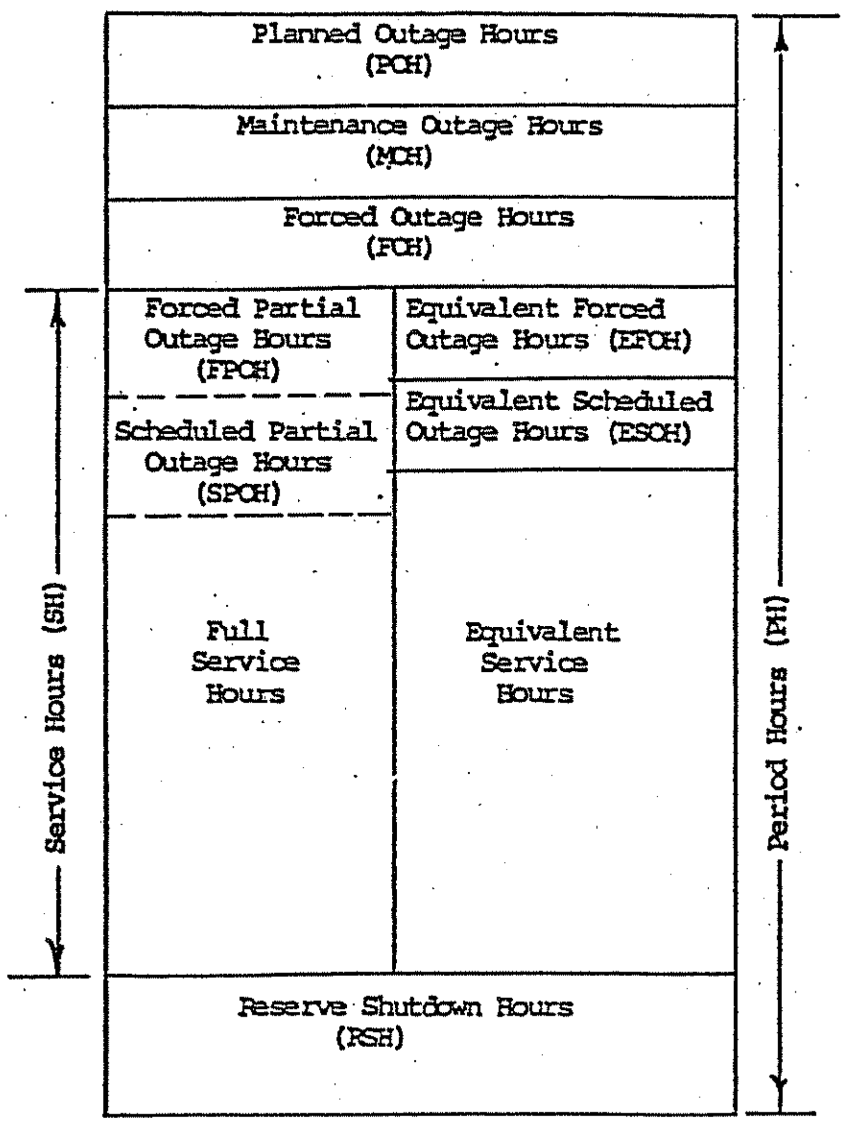
MW Net - Megawatts Net - Net megawatts available from a unit or plant excluding station use. For our purpose here:

$$\text{MW Net} = \text{MDC} * \frac{\text{Net Generation mwh}}{\text{Gross Generation mwh}}$$

Figure 1 on the next page illustrates some of the above terms.

For our purposes, I have specified different definitions for and uses of the terms planned outage, maintenance outage, and scheduled outage than we have commonly used in the past. Maintenance outages or

Figure 1
Thermal Unit Availability Statistics
Definitions



scheduled outages are interchangeable terms. They both refer to unit outages which are scheduled or known a relatively short time in advance, i.e., a few days. These outages are treated like forced outages.

A planned outage is known months in advance. This outage is usually the annual maintenance shutdown. Planned outages are to be specifically used in rate-making cost of power caluclations by showing a unit as being out-of-service. Planned outages are not reflected in calculations for the Equivalent Outage Rate (EOR).

PROCEDURES

For rate-making cost of power calculations the mw available for each thermal unit are to be calculated as indiciated earlier, that is mw available = (1.0 - EOR) * (MW Net). A plant's mw available is the sum of all units' mw available. Utilities may aggregate several thermal units at one site into a plant for rate-making purposes.

The megawatts available from thermal units for rate making will generally be less than megawatts used by the utilities for Coordination Agreement purposes. The reason is the agreement permits utilities to inflate, within limits, the expected average megawatts available from the thermal plants. On average, it is to the benefit of the utilities and their ratepayers to do so. Utilities can borrow amounts of energy from the Northwest hydro system based on the firm energy resources which they report they have available. The utilities gamble that they can repay the borrowed energy from future hydro energy. In poor hydro years, they must repay energy from their thermal resources.

The procedures for calculating EFOH and ESOH are illustrated on the following two pages. The procedures are alike. It can be seen that EFOH and ESOH are the sum of equivalent outage hours for several partial forced or partial scheduled outages.

The EOR and MW Net are to be calculated using the most recent available 48-calendar months of performance data for each thermal unit. For thermal units with less than 48 months operation, i.e., Colstrip #3 and Valmy, the Equivalent Outage Rate to be used will be the weighted (by number of months) average of actual historical performance and national averages. The national averages I will use are shown on page 3 of Appendix "A." Those averages were compiled and published by the Thermal Resources Committee of PNUCC. The source of data is the North American Electric Reliability Council (NERC). Members of the Thermal Resources Committee include representatives of several Northwest utilities, including Portland General Electric and Pacific Power & Light. The numbers shown in the appendix are illustration only. I expect the utilities to annually furnish updated data reflecting national average performance of new thermal plants.

An example: If PGE files for a rate increase when Colstrip is two years old, PGE will have 24 months of historical data. Obviously, we will not know what the EOR for Colstrip #3 will be in its third

FIGURE 2

EQUIVALENT FORCED OUTAGE HOURS

ILLUSTRATION

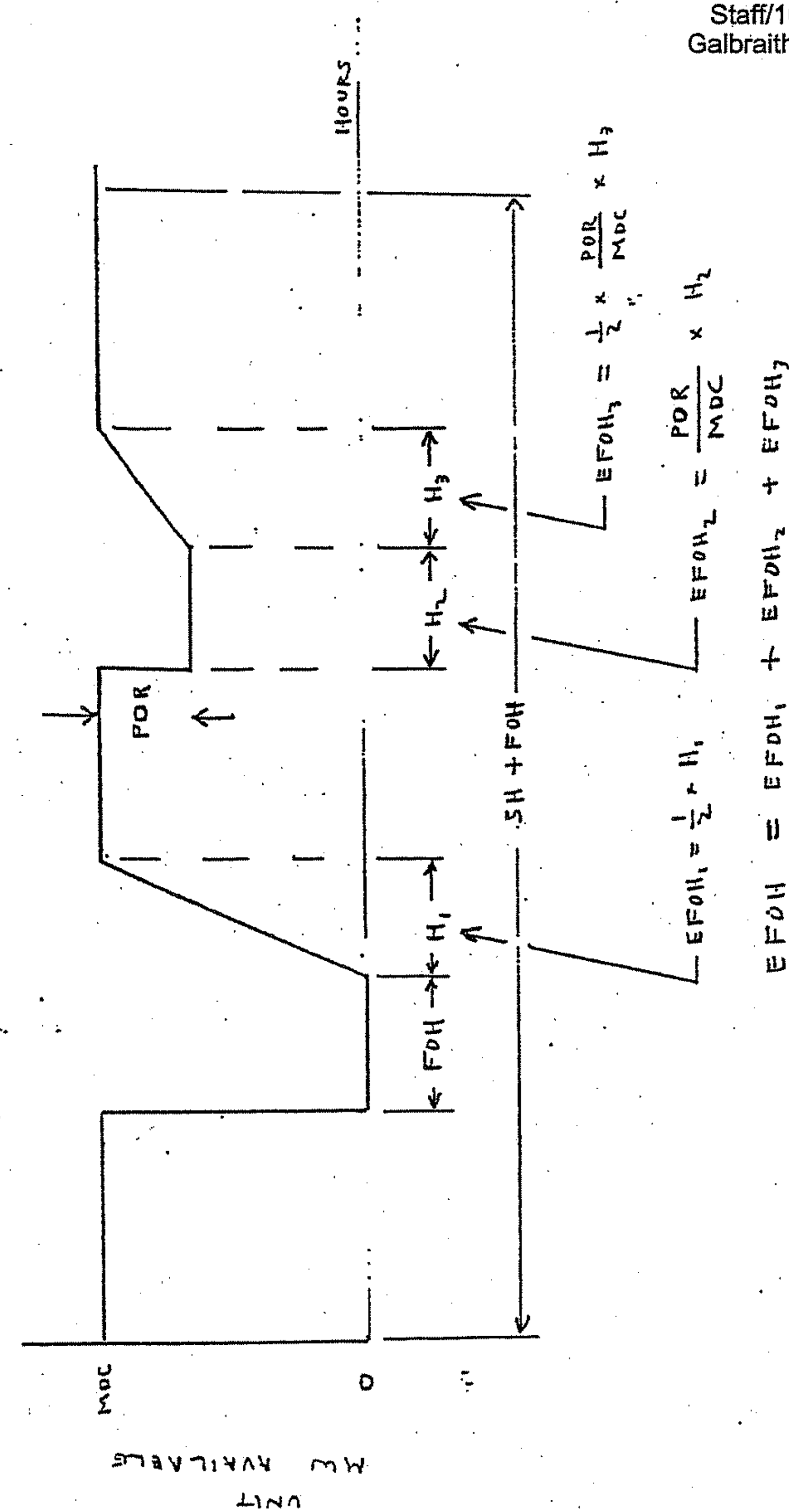
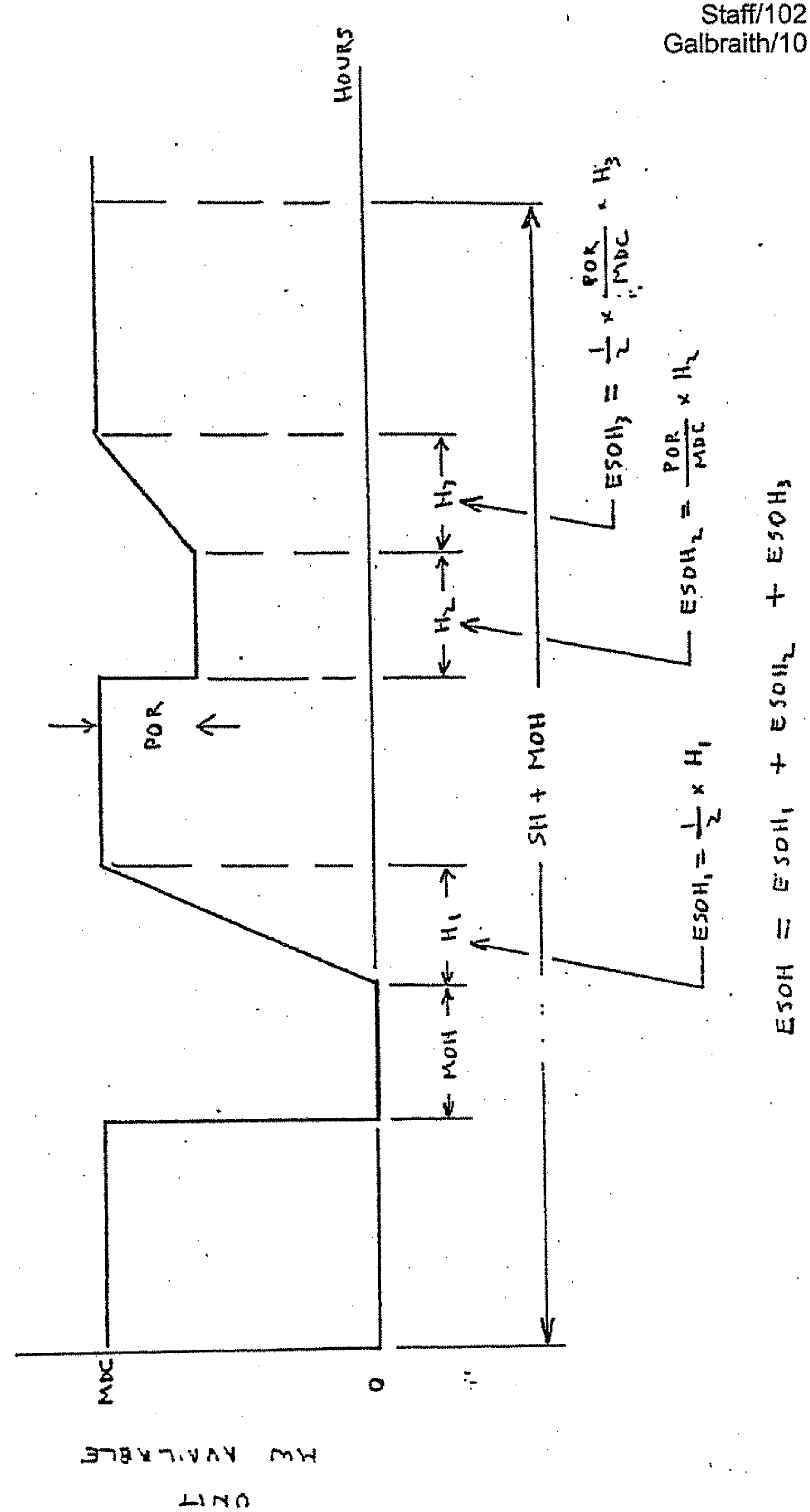


Figure 3
Equivalent Scheduled Outage Hours
Illustration



year. From the appendix we see the national average Forced Outage Rate for coal units of Colstrip's approximate size for the third year of operation is 12.3 percent. I shall use Forced Outage Rate, which differs slightly from EOR, for new plants because that is the data available from the PNUCC. However, we need to give some consideration to Colstrip's two years of actual operation. Let us assume the EOR for two years is actually 16.0 percent. The weighted (by number of months) average of 24 months at 16.0 percent and 12 months at 12.3 percent is 14.8 percent. *

Therefore, the estimated EOR for Colstrip #3 for that coming year would be 14.8 percent. The mw available will be (1.0 - 0.148) * (700 mw) = 596.4 mw for the unit. PGE should show their 20 percent share as 119 mw for the approximate 11 months per year Colstrip #3 is scheduled to be on line.

A utility may use, for rate-making purposes, the same equivalent outage rate and planned maintenance schedule that it uses for the Coordination Agreement. I suggest that if a utility cannot provide adequate data, calculations, and workpapers to support lower performance levels (higher EOR or lower annual availability), then the PUC staff should seriously consider using Coordination Agreement values.

Whats this?

The MW Net calculation is to be used to reflect station use. That is, MW Net excludes station use. In power cost calculations, station use should not be a separate line item nor added to system load. I shall calculate MW Net as indicated earlier, that is:

$$\text{MW Net} = \text{MDC} * \frac{\text{Net Generation mwh}}{\text{Gross Generation mwh}}$$

NRSS

Portland General Electric includes in their power cost calculations a line item called non-running station service. That item is effectively a load. It is correct to use only for months a unit is planned to be off line, i.e., during planned annual maintenance. For months the unit is planned to be in service, station use is incorporated in the MW Net calculation. An alternative, which I prefer, is to have net generation mwh reflect energy used by a thermal unit when it is shutdown. In that case, non-running station service must not be specifically included in power costs.

The annual planned maintenance for rate making for each unit should be an average of a four-year cycle actual planned outages. The reason I chose a four-year average is that actual planned outages run different numbers of days from what was scheduled during the previous year. In actual practice, utilities vary from the previously scheduled outage dates in response to operating conditions.

Utilities normally expect to have relatively short planned outages for three years out of four, and a longer outage one year. The four-year average should be reflected in cost of power calculations rather than the expected planned outage during the test year for a rate case. If, over time, the actual length of planned outages varies over a five- or six-year cycle, then that should be reflected in rate making.

THERMAL PLANTS

In the following pages I shall discuss each thermal plant separately. All the data shown are calculated from data now available to me. In the coming weeks I expect Portland General Electric to provide up-to-date data for Boardman. Both Pacific Power & Light and PGE are trying to get Montana Power Company to develop and provide appropriate data for Colstrip.

The data shown below will be changed over time as more recent data is provided by the utilities. For each rate filing the utilities will need to provide updated data and, if necessary, supporting workpapers.

Portland General Electric

Trojan

MDC	1080 mw
EOR	16.4% (6/80-5/84)
Planned Maintenance	71 days
Available (Month-to-Month)	609 mw (PGE share)
	23 mw (PP&L share)
Primary Utility	PGE

The EOR calculated for Trojan is for 48 months calendar June 1980-May 1984. The procedure I used was based on net mwh produced, which reflects all station use mwh and forced outages. The data comes from Trojan's monthly operating data report, which PGE prepares for the NRC and provides a copy to us. I did not calculate EOR on a month-by-month basis. I do exclude economy, planned refueling, and NRC imposed outages.

The underlying rationale for the procedure that I used is that Trojan normally is run at 100 percent of its capability. The evidence I have seen over the years points to that. There have been some clear-cut economy shutdowns, and one partial backdown for a few days for economy reasons in 1984.

The Trojan monthly operating reports show net mwh produced. The narrative part of each report discusses all outages in detail. From the narrative I determine the net hours each month Trojan should have been available by excluding refueling hours, NRC imposed shutdown hours, economy, and equivalent economy shutdown hours. I sum the net hours available and the net mwh produced over 48 months. The average mw available from Trojan is the sum of mwh divided by the sum of net hours.

For Trojan, I think the annual planned refueling and maintenance outage will vary from 61 to 80 days. The average is about 71 days. Trojan had two very long refueling outages in 1982 and 1983, which would tend to lengthen the average refueling outage. The 1982 refueling outage includes a 1-month forced outage (leaking pressurizer) which is reflected in my calculations for EOR. However, both the 1982 and 1983 refueling outages were effectively extended because of good hydro conditions and both, therefore, are partially economy shutdowns. Those long refueling outages were adjusted before the average refueling outage duration was calculated. Therefore, I believe the averge refueling outage for Trojan should be about 71 days. I developed that number in detail for my testimony in the 1983 Portland General Electric rate case, UE 1/UE 6. The average refueling outage, as adjusted, for four years, 1980 through 1983, is 71 days.

In PGE's 1983 general rate case staff settled with the company, for that case only, on a complicated method to account for Trojan's performance to be used in cost of power calculations. The company made four computer runs, for four repetitions of the test year, changing Trojan's available mw each month to show actual mw produced each month over the past four years. That method is not satisfactory. It is complicated, it entails a lot of hand calculations to average four years' results, and it does not theoretically represent Trojan's expected output over a test year. It does not account for variations in other resources. We are treating one resource, that is Trojan, philosophically different from all the other resources.

I propose we use the most recent 48 months of Trojan's historical performance to estimate available megawatts, the same as for other thermal plants. In general, regulatory (NRC) shutdowns should be excluded because they are extraordinary events. Like other thermal plants, planned maintenance and economic outages are also excluded from the calculation of megawatts available. Of course, the planned refueling outage must be represented in annual power cost calculations on an expected average basis.

Only one computer run of PGE's Power Operations Model, which is the new power cost model, is to be used to calculate the cost of power. The procedure of making four computer runs to cover four years of data is not a theoretically sound way to predict next year's cost of power, nor Trojan's performance. There are some additional power costs which result when the old power cost model is run four times using actual mw for Trojan versus one computer run using average mw for Trojan. Those additional calculated power costs will be reduced in the future because Colstrip #3 is now on line. Colstrip #3 is a low operating cost unit. Its existance will reduce variations in power cost resulting from variations in Trojan's mw output.

In PGE's 1983 general rate case, UE 1/UE 6, the difference in cost of power between four computer runs and one equivalent run was about $765,000. The one run produced the lower cost. After considering PGE's power cost adjustment, the cost to PGE is about $153,000. PGE's total cost of power is about $127,000,000. The cost to PGE from using one computer run is about 0.012 percent of their total power cost. Power cost predictions are never anywhere near that accurate, so using one computer run instead of four is well within normal accuracy limits.

I have shown an Equivalent Outage Rate (EOR) for Trojan of 16.4 percent. That translates into using 609 mw available at Trojan for PGE. Actually the 16.4 percent EOR is fiction. It reflects thousands of megawatt hours of non-running station use; however, the 609 mw itself is reasonable. PGE's power operations model includes a non-running station service as a separate line item. That line item includes non-running station service for Trojan and for Boardman. Because I exclude station service from available mw, that separate line item must be eliminated.

For Trojan, I suggest we use the average of actual historical mw produced at Trojan over the most recent rolling 48 calendar months. We will not calculate EOR as such, nor availability as a percentage. Of course, we will exclude regulatory, planned refueling, and the economy shutdowns, both full and partial, from the 48-month average.

Boardman

MDC	530 mw
EOR	14.2%
Planned Maintenance	4 weeks
Available	356 mw (PGE share)
	44 mw (IPC share)
Primary Utility	PGE

The available mw excludes station use. The EOR shown is calculated from 38 months, August 1980 through September 1983 of actual, 13.7 percent, and 10 months of national average, 16.2 percent forced outage rate. The national average data is shown on page 3 of the appendix attached to this memo. For coal plants of Boardman's size for the fourth year of operation, the average forced outage rate is 16.2 percent. In PGE's next general rate filing there will be 48 months of actual data available from Boardman, so the national average data will not be used.

The Equivalent Outage Rate that I have calculated for Boardman excludes all outages caused by the turbine blade problem. Also, it excludes planned and economy shutdowns. There are two reasons for excluding the turbine blade outages. One reason is that the problem was extraordinary. The Oregon PUC, as well as all jurisdictions, does not consider extraordinary, nonrecurring events for rate making. We set rates based on normal, ongoing expected conditions.

The second reason is that the turbine blade problem has been repaired. It was repaired in the spring of 1982. There was an additional fix made to the turbine blades in September 1983.

Colstrip #3

MDC (Maximum Dependable Capacity)	700 mw
EOR	17.3%
Planned Maintenance	4 weeks
Available	116 mw (PGE share)
	58 mw (PP&L share)
Primary Utility	PGE & PP&L

The EOR shown is for the first year only. It was taken from the national average data for the first year of service, which are shown on page 3 of the appendix. For the second year of operation we will calculate a weighted EOR using several months' actual data as available, and subsequent years national average forced outage rates. In addition, we will assess an appropriate planned maintenance duration, for the second and future years of operation.

Colstrip #4

MDC	700 mw
EOR	17.3%
Planned Maintenance	4 weeks
Available	116 mw (PGE share)
	58 mw (PP&L share)
Primary Utility	PGE & PP&L

The EOR shown is for the first year only. It is taken from the national average data for the first year of service, which are shown on page 3 of the appendix.

Idaho Power Company

Valmy 1

MDC	264 mw
EOR	6.96%
Planned Maintenance	4 weeks
Available	115 mw (IPC share)
Primary Utility	IPC

The EOR shown is calculated from 29 months, late December 1981 through May 1984, of actual data at 6.4 percent, seven months of third year national average data at 7.7 percent, and five months of fourth year national average data at 9.2 percent.

The actual data was taken from a Unit Data Summary report through May 1984, supplied by Idaho Power Company.

Valmy 2

MDC	264 mw
EOR	12.8%
Planned Maintenance	4 weeks
Available	115 mw (IPC share)
Primary Utility	IPC

The EOR shown is taken from the national average, for the first year of operation, for coal plants of Valmy's size.

Pacific Power & Light

The following data for four Pacific Power & Light plants is calculated from the monthly unit data summary for each unit for April 1984. The data reflects 48 months of operation for each unit through April 30, 1984. The planned maintenance shows Pacific Power's long-term cycle average for planned outage duration for each plant. The days outage duration shown are unit-days.

Jim Bridger 1-4

MDC	510 mw each (2040 mw total)
EOR	19.6%
Planned Maintenance	148 days (total 4 units)
Available	1529 mw (" " ")
	1019 mw (PP&L share, total)
	510 mw (IPC share, total)
Primary Utility	PP&L

Dave Johnston 1-4

MDC	785 mw (total 4 units)
EOR	13.0%
Planned Maintenance	113 days (total)
Available	633 mw (")
Primary Utility	PP&L

Wyodak

MDC	345 mw
EOR	3.5%
Planned Maintenance	28 days
Available	241 mw (PP&L share)
Primary Utility	PP&L

Centralia 1-2

MDC	665 mw each (1330 mw total)
EOR	13.1%
Planned Maintenance	74 days (total 2 units)
Available	522 mw (PP&L share, total)
	27 mw (PGE share, total)
Primary Utility	PP&L

The above data for each MDC rating reflects the data available to me now. For each rate filing the utilities will need to provide up-to-date information and, if necessary, supporting documents.

PLANNED AND ECONOMY OUTAGES

The EOR indicated for the above thermal plants was calculated excluding planned and economy outages. Where data was available, the EOR was calculated as a 48-calendar month average. For rate making, cost of power calculations will use (1.0 - EOR) * (MW Net) as the unit or plant megawatts available for the several months each year the unit is scheduled to be on line. In addition, the cost of power calculations need to reflect planned maintenance outages for each unit or plant.

For the coal plants listed earlier, annual planned maintenance varies from three to six weeks. I prefer that utilities use a long-run cycle average for planned outage duration for rate making. As an alternative, <u>the above estimates of annual planned maintenance may be altered annually by the utilities with staff's concurrence to reflect the expected maintenance schedule for the test period used in a rate case</u>.

The procedure I propose excludes reserve shutdown (economy outages) and planned maintenance outages from the calculation of Equivalent Outage Rate (EOR). Economy and planned outages do not count for nor against utilities. If we use this procedure, then the theoretical problem of considering a unit as 100 percent available during a reserve shutdown does not exist. PGE and PP&L have argued that a plant should not be considered 100 percent available when it is not running, because if it were operated there would be, on average, some forced outages. Their's is a reasonable argument.

Occasionally we will need to determine if an outage was a forced or a reserve (economy) shutdown. The outage will be considered a reserve (economy) shutdown unless the utility provides a clear, definite explanation of the cause.

GENERAL INFORMATION

The only thermal plants of concern in this memo are those discussed earlier. Some data about each plant is also listed in the attached appendix. Beaver and other combustion turbines and diesel units are not covered by this memo because their maximum performance, or maximum available mw, have not been serious issues in rate making.

I do not suggest the PUC accept "carte blanche" whatever Equivalent Outage Rate (EOR) or MW Net the utilities calculate for each unit, even if such actually occurred. As in all aspects of rate making, if we can reasonably establish that substandard performance was due to poor or imprudent management then we can and should disallow some cost or adjust the historical EOR or MW Net. That applies even to data I have shown earlier.

The list of thermal plants discussed earlier and also shown in the appendix indicates the primary utility, i.e., Portland General Electric, Idaho Power Company, or Pacific Power & Light. The primary utility is the one the PUC staff generally will expect to furnish data for the unit and to estimate planned maintenance outages. However, if the primary utility does not furnish appropriate data, the other involved utilities will not be excused.

An exception is Colstrip. There, for the time being, I propose to treat PGE and PP&L as each being responsible to develop the relevent data; however, they need not act independently. I suggest that each act as a check on each other and on Montana Power.

Usually the procedures, data, and results we settle on for the primary utility will be applied to the other utilities for each plant. I am sure there will be exceptions over the years.

bjs/1710m

Attachments

Thermal Plant Performance

Plant	48 Months EOR[1]	48 Months Thru
Trojan	16.4%	5/84
Boardman	14.2	9/83[2]
Colstrip 3	17.3[3]	As of on-line date (1/10/84)
Colstrip 4	17.3	As of on-line date
Valmy 1	7.9	7/83[2]
Valmy 2	12.8	As of on-line date
Bridger 1-4	19.6	4/84
D. Johnston	13.0	"
Wyodak	3.5	"
Centralia 1-2	13.1	"

[1]EOR in percent

[2]EOR includes actual and additional one year from national averages.

[3]National average data. For illustration only until actual performance data is available.

jcp/1014j-1

Thermal Plants

Plant	MDC mw[1]	Primary Utility[2]	Percent Share	Other Utility	Percent Share
Trojan	1080 mw	PGE	67.5%	PP&L	2.5%
Boardman	530	PGE	80.0	IPC	10.0
Colstrip 3	700	PGE	20.0	PP&L[3]	10.0
Colstrip 4	700	PGE	20.0	PP&L[3]	10.0
Valmy 1	254	IPC	50.0		
Valmy 2	254	IPC	50.0		
Bridger 1-4	510 each	PP&L	66.7	IPC	33.3
D Johnston	785 total	PP&L	100.0		
Wyodak	345	PP&L	80.0		
Centralia 1-2	665 each	PP&L	47.5	PGE	2.5

[1]Nameplate rating.

[2]Primary utility for providing data and planned maintenance schedules for Oregon rate making.

[3]For Colstrip PP&L will also be treated as the primary utility.

jcp/1014j-2

Thermal Plants

First four years of service. Values to be averaged with actual performance for plants less than four years old.

Plant	Nameplate MW	Year of Service[1] 1st FOR[2]	2nd FOR	3rd FOR	4th FOR
Boardman[3]	530				16.2
Colstrip 3 & 4	700 ea	17.3	14.7	12.3	15.7
Valmy 1 & 2	254 ea	12.8	6.4	7.7	9.2

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[1]Data: FOR in percent. National figures.
Source: PNUCC Thermal Resources Data Base Addendum February 1, 1983. PNUCC source is North American Electric Reliability Council (NERC).

[2]EOR, Forced Outage Rate

[3]It is expected 48 months data for Boardman will be available before PGE's next rate filing.

jcp/1014j-3

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1355

In the Matter of THE PUBLIC UTILITY COMMISSION OF OREGON Investigation into Forecasting Forced Outage Rates for Electric Generating Units	CONSOLIDATED ISSUES LIST

In accordance with the schedule in this proceeding, the Oregon Public Utility Commission Staff, on behalf of the UM 1355 parties, respectfully submits this consolidated issues list.

UM 1335 Consolidated Issues List

I. What forecasting methodology should the Commission adopt for thermal generating plants?

A. Should there be a different forecasting method for peaker plant versus base load plant?

1. Are there any particular considerations (e.g. combined cycle plant outage rate computations)?

B. Which forced outages should be included in the forced outage rate determination (e.g. extreme events)?

1. What role should industry data play in this determination?

C. What methodology should be employed for treatment of excluded outages?

D. What is the appropriate methodology for calculating forced outage rates and how should that be applied within the power cost model?

E. How should new thermal resources be treated?

F. What is the appropriate length for the historical period?

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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?

III. What wind availability reporting method should the Commission adopt?

A. How should wind availability be appropriately applied to forecasting for a rate determination?

IV. What methodology should the Commission adopt for planned maintenance (e.g. average versus forecast) of thermal, hydro, and wind plants?

A. How should this methodology be applied (e.g. high load/low load split, weekend/weekday split)?

V. What data reporting requirements should the Commission require regarding outages?

DATED this 30th day of January 2009.

Respectfully submitted,

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