BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1355

In the Matter of	)
	)
Investigation into Forecasting Forced Outage Rates for Electric Generating Units.	)
	)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

April 7, 2009

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My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

This docket concerns the forecasting methodology used to predict the amount of forced outages and other downtime a generating plant will experience in a given year. In Oregon, we generally use forward-looking test years. Calculating the Forced Outage Rate (FOR) for a plant is useful because it can help forecast future plant performance. It is important to remember that the purpose of the FOR is not to allow recovery of the cost associated with past outages. Past outages are only relevant if those events may be predictors of future performance.

II. Issues

My testimony, on behalf of CUB, will proceed through the items in the Consolidated Issues List submitted to the Parties on January 30, 2009.

A. Thermal Plant Forecasting Methodology

A number of questions are raised with regards to which methodology the Commission should adopt as its standard forecasting method for thermal generating plants.

i. Peaker Plants vs. Base Load

CUB believes that there are fundamental differences between base load generating facilities and peaker plants that must be addressed in their respective forecasting methodologies. While base load thermal plants operate on a near-constant, predictable schedule, peaker plants operate on a conditional basis. As such, operators of peaker plants should be able to schedule maintenance during times when demand is predicted to be low, thereby ensuring that the plants are available when needed. Furthermore, utilities have a limited ability to predict forced outages that will coincide with the times in which demand will require peaker plants to be operational. This fact alone is reason enough to mandate the use of separate forecasting mechanisms for the outage rates of base load and peaker plants.

Hydro production, natural gas prices, wholesale electricity prices, and demand loads have a great deal of impact on the annual production at a peaker plant – much more so than its FOR. This makes it much more difficult for a peaker plant to forecast future performance based on historic performance data.

ICNU has proposed using the Equivalent Forced Outage Rate demand (EFOR-d) methodology for peaker units. ICNU describes this as "an industry standard measure of peaking unit electrical generating plant reliability that determines the likelihood the resource will be available during its normal 'demand period'."[1] We concur. Using a four-year rolling average makes sense for base load facilities, but not for peaker units. Using a methodology that is an industry standard makes more sense for peaker units that do not operate for much of the year.

ii. Which events to include?

Outage forecasts for base load thermal power plants are calculated using a rolling average of outage events that occurred during the prior four-year period. It is CUB's position that only events that are likely to reoccur in future years should be included in this four-year rolling average. This means that events like routine and recurring maintenance should be included in outage forecasts. But, given that we know the unexpected can and does happen, we believe we should include some time in the FOR for events such as non-catastrophic equipment failure that cannot be predicted with certainty, but do tend to occur on a somewhat regular basis. Using the FOR methodology to account for these unexpected events would be reasonable, so long as we remember that we are only using an approximation to try to predict the level of forced outages that will likely occur in a given period.

Notwithstanding the above, truly unpredictable events such as extreme weather conditions, seismic activity, terrorism, or other factors that are highly unlikely to repeat with any regularity should be excluded from forecast calculations. Outages due to utility imprudence, such as poor plant management, should also be excluded from the forecast, even if management methods for that plant are expected to remain in place for the foreseeable future; failure to exclude these outages could result in the perverse incentive

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[1] UM 1355, Outage Proposal of ICNU, 10-2-08, page 5.

of rewarding a poorly-performing facility. Finally, outages of significant length that would not be likely to happen over the next four years should not be included in the FOR.

The cause and duration of a given outage should be taken into account when considering whether an event should be included in the rolling average. Although it may be difficult to establish a hard-and-fast rubric that could encompass all potential causes of outages, the establishment of a general set of guidelines, coupled with a standardized review process, would likely cover almost all events. Ultimately, we have to review the historic outages that a utility proposes to include in the FOR and make a judgment as to whether that outage should be used to predict future performance of the plant.

iii. How to adjust for excluded outages?

First, we note that one should not assume that a rate adjustment is required when an outage is excluded from the FOR. Cost recovery should not be granted if the exclusion is due to imprudent management, as customers should not be made to pay for a utility's imprudence. In addition, if the exclusion is due to a factual determination that the outage is unlikely to reoccur, and the financial cost of the outage is not large enough to trigger deferred ratemaking, then it is likely that cost recovery would be inappropriate.

Notwithstanding the above, where appropriate, outages that are not included in the forecast can be accounted for through a Power Cost Adjustment Mechanism (PCAM) for utilities that use this mechanism, or through the use of deferred accounting for utilities that do not have PCAMs. It should be noted that when using the PCAM or deferred accounting, the recovery methodology usually would divide the cost impact of the outage between customers and the utility.

iv. How to apply forced outage rates within the power cost model?

Forced outage rates can be accommodated in a utility's power cost model without great difficulty. The generally-accepted forecasting model is one that utilizes a four-year rolling average to determine the appropriate expected outage period. Because by definition we cannot predict when a forced outage will occur, we then model the outage by "derating" the plant – that is, by reducing the capacity factor of the plant. For example, a plant that is expected to have a forced outage of 3.65 days over the course of a year would have its capacity factor reduced by 1%. This method spreads the likelihood of the outage equally over all hours of the year.

v. How to treat new thermal resources?

New thermal generation resources should be integrated into outage forecasts according to available industry data. For a given type of facility, an estimate should be calculated using historical outage data from similar plants that operate under similar conditions. This historical outage data estimate can then be combined with additional data such as plant design expectations, generation projections produced during the bidding process, etc., to produce a usable forecast for the initial years of the new thermal generation plant's operation. During the first three years of operation, the plant's first, second and third annual operating histories can be combined with the other estimates discussed above to improve the forecast. This data should not, however, be considered to be fully indicative of future operating conditions at the plant, as early-stage plant operation often requires an increased maintenance and inspection schedule to ensure the new resource is operating properly. This increased maintenance and inspection schedule generally tails off after the early operating stage, and is not repeated.

In the text above I mentioned generation projections during the bidding process, and I want to highlight that as a consideration. As Oregon has grappled with establishing a competitive bidding process for generation investments, complaints have arisen from independent power producers that utilities can "game" the bidding process, because utilities are not "held" to their bids in the same manner as independent producers. Without weighing in on this conflict, I note that one of the ways for a utility to "game" the bid is to forecast greater production from the facility than will actually occur. Requiring that the initial forced outage rate be at least as favorable as was projected in the competitive bidding process may help protect the integrity of the process.

vi. What is the appropriate historical period?

CUB sees no reason to change the current four-year historical period standard for calculation of outage forecasts. If compelling evidence can be produced that a different historical period should be used, CUB would be open to discussing a change in the calculation methodology. CUB notes, however, that it may be appropriate to exclude a period of time from the FOR forecast period if it does not reflect expected operations, e.g. an extended catastrophic outage. In such a case it would be reasonable to add additional time to the normal four-year period, so as to ensure that 48 months of actual operations under normal circumstances are included in the forecast.

vii. Should non-outage related adjustments be included?

CUB takes no position on this issue.

viii. Should adjustments be made for new capital investments?

Any new capital investment that helps to improve the reliability of generation facilities should trigger an immediate adjustment in the FOR forecast to reflect that increase in reliability. While utilities might argue that it is better to wait and allow the new investment to improve the four-year rolling average, this creates a mismatch between costs and benefits. Customers would have to wait four years before they would see the full benefit of the investment, even though they are expected to begin paying for the investment when it is added to the ratebase. In addition, this practice would require the customers to assume the entire risk of whether the new investment actually is used and useful in terms of increasing reliability.

B. Hydro Plant Forecasting Methodology

The inherent fluctuation in annual hydro generation availability makes forecasting for these resources difficult. CUB supports the traditional method of relying on historic precipitation and streamflow averages and projecting the amount of generation based on that streamflow. By using a historic period (often decades), we can calculate the relationship between the flow of water through a facility and the output of electricity. This historic relationship can take into account a variety of variables, including precipitation and outages.

C. Wind Generation Reporting Methodology

Wind generation availability is somewhat easier to forecast than hydro generation, at least on an annual basis. While hourly, daily, and seasonal fluctuations may make short-term forecasting difficult, annual forecasting is less variable. The fact that, by their nature, wind generation facilities include multiple generation turbines adds complexity to this calculation. All turbines in a wind farm are rarely offline at the same time, unless there are issues with transmission or control facilities. Outage of individual turbines can be reflected in the overall capacity factor of the wind facility.

i. How to apply wind forecasting to rates?

Planned availability for generation for a wind facility is already subject to a number of forecast mechanisms. Again, by their nature, wind turbines are subject to short-term fluctuations in generation that utilities must constantly monitor to balance load. Rates are currently determined using an estimated average that is determined during Integrated Resource Planning (IRP). Scheduled maintenance and forced outages are turbine specific, and therefore less likely to seriously impact the wind project in the same manner as a thermal or hydro plant.

During the first five years of a wind project, CUB supports using the performance forecast (capacity factor) that was used in the competitive bid (Request for Proposals – RFP). This is an area where we have heard a great deal of concern from independent power producers, who are concerned that utilities can win bids by inflating the wind capacity factor in their RFPs. By ensuring that the capacity factor is at least as high as was considered in the bidding process, we can discourage such practices. After the first five years of operation there will be enough performance data available to help set the capacity factor.

D. Planned Maintenance Calculation Methodology

Numerous factors must be considered in the Commission's adoption of a standard methodology for incorporating planned maintenance outages into rates. Utilities may have vastly different maintenance schedules on similar facilities, with one conducting routine maintenance on an annual basis while another conducts the same procedure every two or four years. If an average is to be adopted, careful consideration should be given to this type of schedule differentiation, as shorter averages may favor utilities that conduct more frequent maintenance. Similarly, the Commission must also be careful in its calculations when using a forecast in place of an average. Utilities may be able to manipulate their maintenance schedules to take advantage of a forecast in a particular year; a fairly-calculated rolling average may eliminate this particular issue.

CUB generally supports using actual average data rather than forecasts to project planned maintenance. Allowing utilities to charge customers for forecasted maintenance allows them to forecast maintenance outages for longer periods of time than necessary, and can lead to rates that are higher than necessary.

Over the last 7 years, PGE has forecast planned maintenance on its thermal units 24 times[2]. In 16 of these cases (67%), the planned maintenance did not last as long as projected.

PLANT	PLANNED	ACTUAL	
Boardman	236	216	91.53%
Colstrip 3	119	108	90.76%
Colstrip 4	147	108	73.47%
Coyote Springs	91	95	104.40%
Port Westward	32	20	62.50%
TOTAL	625	547	87.52%

Source: PGE Data Response to CUB, Attachment 001-A

PGE projected 625 days of planned maintenance at their thermal plants between 2002 and 2008. These facilities were actually shut down for maintenance for only 547 days, or 87.5% of the projected duration. While it is commendable that PGE was able to reduce costs and save money when it comes to maintenance, it is unclear whether this discrepancy represents real efficiencies or whether the Company overestimated the

[2] CUB Exhibit 101.

amount of time needed for maintenance. Either way, customers have been paying for planned maintenance that did not occur.

Contributing to our discomfort with this discrepancy is PGE's proposal in the AUT that would allow the Company to update planned maintenance through the case, including after staff and intervenors have filed testimony[3]. This proposal would allow PGE to increase rates by adding planned maintenance late in a proceeding without anyone being able to challenge the Company's plans.

i. How to apply the methodology?

The formal application of either an average or a forecast must also be fine-tuned to consider the timing of scheduled outages. Maintenance outages have differing impacts depending on whether they occur during peak or non-peak generating periods, or on weekends or during the workweek. Standard industry practices, as well as the historic maintenance schedules of the utilities in question, should be considered in these calculations. Most importantly, however, we should expect utilities to maintain their plants in a manner that minimizes costs to ratepayers.

Finally, I note that CUB was really struck by the difference between utility maintenance practices with regard to their respective generation plants. During workshops for this docket, CUB learned that one utility plans an annual maintenance outage for coal plants, while another plans a maintenance outage for each of its coal plants only once every 4 years. Given the wide disparity in the maintenance practices for the respective coal plants, it is doubtful that both utilities can be operating prudently. Either one is doing maintenance that is well beyond what is necessary to maintain the

[3] UE 208/PGE/100/Niman-Tinker/1.

plant, or the other is taking a large risk that its lax maintenance practices could lead to a catastrophic failure.

E. Data Reporting Requirements

CUB recommends that the Commission adopt a standardized reporting requirement for plant outages. A detailed report should be filed for each plant outage that is in excess of 24 hours in length. These reports should include:

- details regarding the cause of the outage, including but not limited to, whether the outage was related to human, mechanical, animal, and/or weather conditions and actions
- details regarding the duration of the outage
- details regarding the maintenance, and time necessary to perform the maintenance, required to resume partial and ultimately full electricity generation capacity.
- data regarding other activities during the outage, including whether scheduled maintenance was performed during the outage period.
- data regarding the cost of replacement power purchased during the outage
- copies of any report(s) provided to senior management in regard to the outage, including but not limited to:
    - cause
    - duration
    - cost of replacement power
    - repairs and/or maintenance required to restore partial and ultimately full electricity generation

- the cost of the repair and/or maintenance required to restore partial and ultimately full electricity generation
- steps, if any, to be taken to prevent similar outages in the future

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

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TITLE: Executive Director

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EDUCATION: Bachelor of Science, Economics
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EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 197, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, and UM 1209. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, Environment Oregon Research and Policy Center
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

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	0	44	0	0	0	20	17	16	12
UE 172	2006 RVM	2006	29	0	9	0	52	0	16	0	na	na
UE 161	2005 RVM	2005	32	0	7	0	7	0	9	0	na	na
UE 149	2004 RVM	2004	69	0	44	0	0	0	0	0	na	na
UE 139	2003 RVM	2003	30	0	0	0	58	0	28	0	na	na
UE 115	GRC, 2002 Test Year	2002	16	0	15	0	30	0	9	0	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.

UM 1355 – CERTIFICATE OF SERVICE

I hereby certify that, on this 7th day of April, 2009, I served the foregoing **OPENING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON, (CUB 100/Jenks; CUB 101 Witness Qualifications Statement, Bob Jenks; and CUB 102 UM 1355 Investigation into Forced Outage Rate, PGE Thermal Plants, Forecasted and Actual Planned Maintenance Outages)** in docket UM 1355 upon each party listed in the UM 1355 PUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending an original and five copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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