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July 8, 2009

Via Electronic and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2010 Annual Power Cost Update Tariff (Schedule 125)
Docket No. UE 208

Dear Filing Center:

Enclosed please find an original and five copies of the Direct Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket. The confidential pages and exhibits are inserted in separate envelopes and sealed pursuant to the protective order in this proceeding. Also enclosed is a complete Redacted Version of the confidential exhibit ICNU/103.

Thank you for your assistance and please do not hesitate to give me a call if you have any additional questions.

Sincerely yours,

/s/ Brendan E. Levenick
Brendan E. Levenick

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony and Exhibits of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the official service list shown below for UE 208, via U.S. Mail. A Redacted Version of confidential exhibit ICNU/103 was served via electronic mail.

Dated at Portland, Oregon, this 8th day of July, 2009.

/s/ Brendan E. Levenick
Brendan E. Levenick

(W) CITIZENS' UTILITY BOARD OF OREGON G. CATRIONA MCCRACKEN **(C)** ROBERT JENKS **(C)** 610 SW BROADWAY STE 308 PORTLAND OR 97205 dockets@oregoncub.org bob@oregoncub.org	**DEPARTMENT OF JUSTICE** STEPHANIE ANDRUS **(C)** ASSISTANT ATTORNEY 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
OREGON PUBLIC UTILITY COMMISSION ED DURRENBERGER **(C)** PO BOX 2148 SALEM OR 97308-2148 ed.durrenberger@state.or.us	**PORTLAND GENERAL ELECTRIC** RANDALL DAHLGREN RATES & REGULATORY AFFAIRS 121 SW SALMON ST 1WTC 0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
PORTLAND GENERAL ELECTRIC DOUGLAS C TINGEY ASST GENERAL COUNSEL 121 SW SALMON 1WTC13 PORTLAND OR 97204 doug.tingey@pgn.com	

W = Waived Paper Service

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 208

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for Net Variable Power Cost Revision.	)
	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

July 8, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Sandy Springs, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design, and fuel cost recovery issues.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101. I have participated in and filed testimony in numerous cases involving Portland General Electric Company ("PGE" or the "Company") and PacifiCorp net power cost issues over the past ten years.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to examine PGE's proposed net power cost study for the 2010 Annual Update Tariff ("AUT"). I have identified certain issues related to the PGE MONET study that should be addressed in the final order in this case.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have concluded as follows:

1. PGE appears to have implemented the applicable adjustments from the stipulation in UE 198. PGE also complied with the requirements of the stipulation in that case to provide Minimum Filing Requirements ("MFRs") to support its request. I believe the MFRs have been of great value in this case in reducing discovery and streamlining the processing of this case.

2. There are a number of issues that are pending in UM 1355, the resolution of which would have an impact on this case. I briefly explain each issue and quantify the impact on the 2010 AUT. All of these adjustments are appropriate for application in this case irrespective of the outcome of UM 1355.

3. I recommend an adjustment to reduce Net Variable Power Costs ("NPC") due to use of a planned outage schedule based on a four-year rolling average, rather than a forecast of the 2010 schedule. This is shown on Table 1 as Adjustment No. 1

4. I recommend an adjustment to the Boardman forced outage rate to bring the 2006 outage rate into the 90th percentile of a comparison group of North American Electric Reliability Corporation ("NERC") coal plants. This is shown on Table 1 as Adjustment No. 2.

5. I recommend an adjustment to reflect a split between Heavy Load Hour ("HLH") and Light Load Hour ("LLH") scheduling of deferrable maintenance events. Statistical data and sound utility practice justify this adjustment. This is shown on Table 1 as Adjustment No. 3.

6. I recommend an adjustment to the Beaver plant outage rates to eliminate deferrable maintenance events from the computation of outage rates as these events can be scheduled to occur at times when Beaver is "out of the money." This is shown on Table 1 as Adjustment No. 4.

7. I reflect a recent substantial load reduction by a large industrial customer that is a member of ICNU in calculating the 2010 AUT, with the expectation that PGE will verify this situation and make an appropriate update in its load forecast update. This is shown on Table 1 as Adjustment No. 5.

8. My recommended NPC for 2010 based on the current filing is shown on Table 1.

Table 1 NPC Adjustments
($1000)

PGE Requested NPC			**830697**
Adjustments			
No.	**Description**		
1	**4 Yr. Average Planned Outage Schedule**		**-2070**
2	**NERC Collar 2006 Boardman**		**-907**
3	**HLH/LLH Outage Rate Split**		**-99**
4	**Remove Beaver Deferrable Outages**		**-308**
5	**SP Newsprint Load Reduction**		**-16954**
		Total	**-20338**
Final Allowed NPC			**810358**

II. NET VARIABLE POWER COST ISSUES

Q. WHAT ARE "NET VARIABLE POWER COSTS" AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Net variable power costs are the variable production costs related to fuel and purchased power expenses, net of power sales revenue. In the context of this case, net variable power costs are estimated using PGE's MONET production cost model. Based on the Commission decision in UE 198 (Order No. 08-505), PGE is allowed to update Schedule 125 each year in the AUT process. According to the current tariff, updates are limited as follows:

1. Forced Outage Rates based on a four-year rolling average;
2. Projected planned plant outages;
3. Forward market prices for both gas and electricity;
4. Projected loads;
5. Contracts for the purchase or sale of power and fuel;
6. Changes in hedges, options, and other financial instruments used to serve retail load;
7. Transportation contracts and other fixed transportation costs; and
8. No other changes or updates will be made in the annual filings under this schedule.

Schedule 125, Original Sheet No. 125-2.

Q. WHAT INFORMATION, DOCUMENTS, AND DATA DID YOU REVIEW IN ORDER TO ANALYZE PGE'S POWER COSTS?

A. I read PGE's direct testimony and MFRs and examined the modeling assumptions used in PGE's MONET power cost model in order to make recommendations regarding the proper level of net variable power costs for 2010.

Q. DID THE COMPANY FULLY COMPLY WITH THE REQUIREMENTS FROM THE STIPULATION IN DOCKET NO. UE 198 TO PROVIDE MFRs AND OTHER SUPPORTING DOCUMENTS IN THIS CASE?

A. Yes. The materials provided by the Company were very thorough, well organized, and quite comprehensive. Based on my experience and my discussions with Staff, these efforts made a substantially positive impact on the processing of this case. In UE 198, I found it necessary to file at least 214 data requests, while in this proceeding it was only necessary to file one request. Further, I believe the level and detail of information provided was substantially better than that I obtained in discovery in UE 198, which contributed greatly to the efficient processing of this case.

Q. HAS PGE PRESENTED ITS FINAL MONET RUN IN THIS CASE?

A. Not yet. The Company plans to continue to perform MONET updates as additional information becomes available. The changes I recommend to MONET should be made by the time the Company files its final MONET run for 2010 power costs.

UM 1355 Adjustments

Q. PLEASE EXPLAIN THE STATUS OF UM 1355 AND THE ISSUES UNDER CONSIDERATION IN THAT CASE.

A. UM 1355 was established by the Commission to address issues that have arisen in the modeling of forced outage rates in power cost models in recent cases. Exhibit ICNU/102 is a copy of the approved issues list in UM 1355.

The UM 1355 docket has been active since early 2008, and the Parties have conducted a number of workshops in that case and have already filed two rounds of testimony. There also have been a number of settlement conferences. While settlement remains elusive, the parties are at least making some progress informally in terms of narrowing the scope of issues. In the case of PGE, I have had several discussions with the Company and have provided them with certain analyses that show different approaches to modeling various issues in UM 1355. In this testimony, I will briefly describe, support and quantify certain adjustments that would arise from implementing ICNU's recommendations in UM 1355 in this proceeding. I recommend these adjustments be adopted irrespective of whether the Commission reaches a decision in UM 1355 in time for application to this docket because there is good cause for doing so in the instant proceeding. Originally, ICNU expected that UM 1355 would be concluded with sufficient time to implement the final order in PGE's 2010 AUT. The final order in UM 1355 will be delayed, in part because the utilities wanted additional time, but the schedule in UM 1355 still allows for an order in time to be implemented in the

2010 AUT. PGE should not be allowed to benefit from any further delay in UM 1355 by increasing power costs based on forced outage issues in this proceeding. In addition, there has been some discussion among the parties in UM 1355 of potentially addressing one or more of the forced outage issues in this proceeding (Docket No. UE 208). If that occurs, then my testimony in UM 1355 that addresses any issues which are moved into UE 208 should also be introduced into the record in UE 208.

Planned Outage Modeling

Q. EXPLAIN THE ISSUES SURROUNDING MODELING OF PLANNED OUTAGES IN THE AUT.

A. While a four-year average is used for computing forced outage rates in MONET, PGE typically uses its budget forecast for modeling of planned outages for the test year. All parties to the UM 1355 docket agree with the continued use of the four-year average for forced outage rate modeling (subject to certain other adjustments to be discussed later). As for planned outages, in UM 1355 Staff, Citizens Utility Board ("CUB"), ICNU and PacifiCorp agree with the use of a four-year historical average for planned outages, while PGE continues to support its use of a forecast instead. I recommend that the planned outages for 2010 be based on the use of a four-year average in this case.

Q. WHAT ARE THE KEY GOALS THE COMMISSION SHOULD CONSIDER IN SELECTING A METHODOLOGY FOR PLANNED OUTAGE MODELING OF THERMAL AND HYDRO RESOURCES?

A. The method used should be transparent, verifiable and devoid of perverse incentives.

Q. WHAT ARE THE PROBLEMS ASSOCIATED WITH USE OF A FORECASTED SCHEDULE?

A. The first problem is that planned outage schedules can and do change in response to external events and forced outages. A forecast prepared more than a year in advance may not reflect what actually happens. A second problem is that such forecasts are not verifiable in any real sense. It would be very difficult to determine, for example, if the utility simply proposed an unrealistic, high cost schedule of planned outages for purposes of increasing cost recovery. It is quite difficult to determine if the forecast is realistic or not, as the duration and timing of planned outages can change dramatically from year to year. This is really an illustration of the problem of perverse incentives. The incentive for the utility is to make *forecasts* that overstate planned outage activities and costs and then to skimp when it comes to actually implementing planned outages.

A further problem is that utilities would then need to remove planned outages from the historical database (i.e., the four year period). There would be a temptation to reclassify events "after the fact" as unplanned, rather than planned.

Q. ARE THERE EXAMPLES THAT ILLUSTRATE THESE PROBLEMS WITH PGE'S USE OF PROJECTED OUTAGE SCHEDULES?

A. Yes. PGE's forecasts of planned outages have sometimes been longer than have actually occurred. A logical explanation for this is that plant managers will seek to use a forecast that is achievable, but has room for some contingencies. When planned outages "go as planned," there will likely be a shorter than budgeted outage.

There also have been other situations involving the problems discussed above. In UE 172, PGE included an outage for the Sullivan hydro plant that had already been included in the prior RVM case, but which did not take place. Parties objected to this treatment which effectively counted costs for the same outage twice. PGE did not dispute that the outage did not actually occur, but argued that it was due to circumstances beyond its control, and that the variance was just one of many unintended events. Re PGE, OPUC Docket No. UE 172, PGE/300, Lobdell-Ninman-Hager/1 (Aug. 19, 2005).

Further, in the case of a longer than expected planned outage at Boardman, PGE reclassified (after the fact) the extension period of that event as being due to a forced outage. That resulted in an increase in NPC because unplanned outages are part of the four-year average used in MONET, while planned outages are removed from the four year-average and replaced with a forecasted schedule.

Finally, in UE 198, parties to the PGE case questioned the assumed timing of a long Boardman outage planned for 2009. This issue was ultimately resolved through the settlement, which was predicated on an assumed shift in the schedule.

None of this is to suggest what the "right" or "wrong" answer was in the above situations. However, it illustrates that, when forecasted schedules are used, there are problems with verification, accuracy of the forecast outcomes, and potential adjustments to the historical data. Use of a purely forecasted schedule does not make the process more transparent, more efficient, or more equitable. It also does not remove the controversy surrounding modeling of planned outages from rate cases. Indeed, as the examples above show, there have been many such problems in recent years. Finally, given that PacifiCorp, Staff, CUB and ICNU recommend use of a four-year average for planned outages and all parties to UM 1355 recommend use of a four-year average for modeling forced outages, I believe it would be a questionable regulatory policy for PGE to apply a different method to planned outages without significant justification or protections to assure equitable results. In this case, PGE has not provided sufficient justification as to why it should be treated differently, and since Staff and intervenors do not have an opportunity to submit additional testimony in this case, the Commission should not consider any new arguments PGE may raise in rebuttal testimony.

Q. WOULD THE ABOVE PROBLEMS HAVE BEEN AVOIDED IF A FOUR-YEAR AVERAGE WAS USED TO DETERMINE UNPLANNED OUTAGES FOR PGE?

A. For the most part they would. There may still have been an issue concerning the proper classification of the longer than expected Boardman outage, but that would have been a less important issue because it would have been included in either planned or forced outages.

Q. ARE THERE ANY UNIQUE CIRCUMSTANCES IN THIS CASE THAT SUPPORT USE OF A FOUR-YEAR AVERAGE INSTEAD OF THE FORECAST?

A. Yes. PGE does not now have an actual forecast for Boardman for 2010, but instead is using a “place holder” outage of 30 days. The Company plans to update its planned outage forecast in a subsequent filing. This complicates the process and creates a situation where parties have no real opportunity to address the new planned outage forecast. As a result, some change to the planned outage modeling in this case is warranted irrespective of the outcome of UM 1355. For these reasons, I recommend the Commission adopt use of a normalization technique based on the same multi-year rolling average as is used for unplanned outages.

Q. HOW HAVE YOU COMPUTED THE OUTAGE SCHEDULE FOR 2010?

A. Confidential Exhibit ICNU/103 shows the development of the assumed schedule and requirements based on actual outages in the four-year period. The only units critical in this analysis are Boardman, Colstrip and Port Westward, as the schedules for the other units are assumed to occur in times when they are "out of the money" and would otherwise not run. For Port Westward, there was not enough historical data to develop either the schedule or requirements, so I used the Company outage duration assumptions, but moved the outage to a period when the plant was out of the money. The results of this adjustment are shown on Table 1.

Boardman Collar Adjustment

Q. PLEASE EXPLAIN THIS ISSUE.

A. In late 2005, the Boardman plant experienced a very long outage. This event gave rise to a deferral in Docket UM 1234, and also played an important role in the establishment of Docket UM 1355. One of the key issues in UM 1355 was the problem of dealing with very long (and presumably non-representative) outage events in power cost forecasts. In UM 1355, Staff witness Kelcey Brown proposed what has become to be called the outage rate "NERC Collar". Re OPUC, OPUC Docket No. UM 1355, Staff/200, Brown/8 (May 13, 2009). In her proposal, a comparison group of NERC plants are identified, and the 90th and 10th

percentile outage rate confidence intervals are determined. Outage rates for plants that are outside these confidence intervals for any particular year are adjusted upwards or downwards to fall into the 90th or 10th percentiles, as appropriate. ICNU supports this Staff proposal.

Q. IS THERE JUSTIFICATION FOR APPLYING THIS METHOD IN THE INSTANT CASE?

A. Yes, for several reasons. First, the NERC Collar method is an objective approach to dealing with the problem of very long outages. It rests on an analysis of industry data provided by NERC and therefore provides a sound basis for forecasting outage rates. In the case of Boardman, PGE has already been allowed a deferral for some of the costs of the November 2005 outage. If the long outage is included in the four year average, customers will end up paying twice for the same event. Further, it is unlikely that such a long outage will occur every four-years, as is the assumption implicit in rolling it into the four-year average.

Q. HOW DOES THE NERC COLLAR METHODOLOGY APPLY IN THIS CASE?

A. The 2006 outage rate for Boardman exceeds the upper limit allowed under the NERC Collar. As a result, that outage rate is reduced in the four year average to the upper limit (the 90th percentile) in the NERC sample. This results in a downward adjustment to NVPC as shown on Table 1.

<u>Forced Outage Rate Modeling and Deferrable Maintenance</u>

Q. WHAT IS DEFERRABLE MAINTENANCE?

A. NERC defines maintenance outages as those outages that can be deferred to beyond the next weekend, but not longer than until the next planned outage. Under the NERC formula, maintenance outages are not considered part of the forced outage rate. Because utilities can defer these kinds of outages until the next weekend or beyond, such outages can be scheduled to coincide with times when lower market prices prevail. In UM 1355, Staff witness Kelcey Brown proposed that outage rates be differentiated between HLH and LLH. ICNU recommends that either a HLH/LLH or Weekend/Weekday split be utilized. In this case, I recommend use of the HLH/LLH split because it reflects the fact that prudent utilities will defer outage and derations where possible to times with the least cost impact. Exhibit ICNU/104 shows an analysis of data for PacifiCorp generators illustrating a strong preference to schedule deferrable outages in the LLH, as opposed to HLH. One of these generators is jointly owned by PGE.

Q. DO YOU RECOMMEND USE OF THE HLH/LLH OUTAGE RATE SPLIT FOR PGE?

A. While I recommend this adjustment be made, the impact is rather small. Nonetheless, it represents an improvement on the techniques being used by the Company in this case and should be applied.

Q. HOW DID YOU COMPUTE THIS ADJUSTMENT?

A. PGE did not have data splitting out the HLH and LLH deferrable maintenance on a unit specific basis, so I estimated the split. For Colstrip, I used publicly available data from PacifiCorp for the period July 2005 through June 2008 to estimate the split.[1/] For Boardman, I used the average split for PacifiCorp's coal units. See Exhibit ICNU/104. For Beaver, this adjustment is not relevant for reasons discussed below. For the other gas plants, the outage rates are low and

1/ PGE uses a four year period that differs by only six months: January 2005 to December 2008.

there is little deferrable maintenance to split between HLH and LLH, so I did not make any adjustment.

I estimated this adjustment outside of the MONET model adjusting the hourly generation for Colstrip and Boardman to reflect the change in outage rates, and I applied those figures to the Mid C market prices curve supplied by the Company. The results of this analysis are shown on Table 1.

Q. ARE THERE ANY OTHER ADJUSTMENTS YOU WOULD PROPOSE FOR OUTAGE RATES?

A. Yes. Even with the correction discussed above, the Beaver plant has a very high unplanned outage rate. A very high proportion of this results from deferrable maintenance. It has been recognized for quite some time that there is a problem in computing outage rates for units with very low capacity factors, such as Beaver 1-7 and Beaver 8, because inclusion of maintenance outages as part of the overall unplanned outage rate overstates the chance of an outage when the plant actually needs to operate. The reason is maintenance outages can be deferred until times when the resource is not needed. For this reason, utilities have developed an alternative outage rate calculation, known as "$EFOR_d$" which if the Equivalent Forced Outage Rate demand, meaning the outage rate during the plants "demand period" – the time it is most likely to run. $EFOR_d$ is defined and reported by NERC, and it is widely used in the industry. The basic premise of the $EFOR_d$ is to discount maintenance outages since they do not need to occur when a low capacity factor resource is required.

Q. SHOULD THE EFOR$_d$ BE APPLIED IN MONET?

A. I recommend it be applied in the case of Beaver Units 1-7 and Beaver 8. For baseload resources, EFOR$_d$ would not make a meaningful change to outage rates, but it would make a substantial difference in the case of a unit with low capacity factors. Based on my discussions with PGE, I found the Company did not have all the data necessary to compute EFOR$_d$. Lacking the actual data for the EFOR$_d$, I estimated it by removing the maintenance outages from the Beaver unplanned outage rate calculation described above. The impact of this adjustment is shown on Table 1.

<u>SP Newsprint Load Reduction</u>

Q. IS SP NEWSPRINT A MEMBER OF ICNU?

A. Yes. This client takes service on the PGE system. Recently, SP Newsprint reduced its load substantially. We do not believe that PGE has factored this load reduction into the 2010 forecast, though the Company has told me they were planning on reflecting this load reduction in the load forecast update. I expect that in the next few months, PGE will continue to investigate these circumstances and determine whether this load reduction is likely to persist beyond 2010. If so, the load forecast update should reflect this load drop. I have estimated the impact of this load reduction on Table 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

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UE 208

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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QUALIFICATIONS OF

RANDALL J. FALKENBERG

ICNU/101

July 8, 2009

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	Electric Co.	Philadelphia Economics of nuclear generating units.
3/85	Case No.	KY	Kentucky Industrial	Louisville Gas	Economics of cancelling fossil

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	9243		Utility Consumers	& Electric Co.	generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 208

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for Net Variable Power Cost	)
Revision.	)
	)

UM 1355
CONSOLIDATED ISSUES LIST

ICNU/102

July 8, 2009

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,

HARDY MYERS
Attorney General

Jason W. Jones, #00059
Assistant Attorney General
Of Attorneys for Public Utility Commission of Oregon

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 208

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for Net Variable Power Cost Revision.	)
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DEVELOPMENT OF MONET PLANNED OUTAGE INPUTS

ICNU/103

REDACTED

July 8, 2009

Development of Monet Planned Outage Inputs

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 208

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for Net Variable Power Cost Revision.	)
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MAINTENANCE OUTAGE AND DERATIONS HOURSFOUR YEARS ENDED JUNE 2008

ICNU/104

July 8, 2009

Exhibit ICNU/104
Maintenance Outage and Derations Hours
Four Years Ended June 2008

Event Type	(All)						
						Disproportionate	
				% Coal	76.9%	92.3%	Coal
	Data			%	64.1%	82.1%	All Units
Unit ID	Sum of Adj HLH	Sum of Adj LLH	HLH	LLH	LLH>HLH	LLH>43.96%	Coal
BLN-1	568	407	568	407	0	0	
BLN-2	216	148	216	148	0	0	
CHO-4	18	49	18	49	1	1	Coal
COL-3	167	227	167	227	1	1	Coal
COL-4	226	309	226	309	1	1	Coal
CRB-1	85	134	85	134	1	1	Coal
CRB-2	173	236	173	236	1	1	Coal
CRG-1	1	1	1	1	0	1	Coal
CRG-2	20	40	20	40	1	1	Coal
CUR-1	86	105	86	105	1	1	
CUR-2	174	177	174	177	1	1	
CUR-3	174	173	174	173	0	1	
DJ-1	7	0	7	0	0	0	Coal
DJ-2	52	85	52	85	1	1	Coal
DJ-3	5	20	5	20	1	1	Coal
DJ-4	385	380	385	380	0	1	Coal
GAD-3	130	123	130	123	0	1	
GAD-4	4	0	4	0	0	0	
GAD-5	45	64	45	64	1	1	
HDN-1	340	243	340	243	0	0	Coal
HDN-2	215	178	215	178	0	1	Coal
HRM-1	104	119	104	119	1	1	
HRM-2	106	85	106	85	0	1	
HTG-1	278	340	278	340	1	1	Coal
HTG-2	312	385	312	385	1	1	Coal
HTR-1	764	791	764	791	1	1	Coal
HTR-2	1,146	1,293	1,146	1,293	1	1	Coal
HTR-3	937	1,116	937	1,116	1	1	Coal
JB-1	349	421	349	421	1	1	Coal
JB-2	213	487	213	487	1	1	Coal
JB-3	309	537	309	537	1	1	Coal
JB-4	140	249	140	249	1	1	Coal
LMT-1	11	0	11	0	0	0	
LS-2	34	47	34	47	1	1	
LS-3	2	0	2	0	0	0	
NTN-1	501	887	501	887	1	1	Coal
NTN-2	326	647	326	647	1	1	Coal
NTN-3	660	924	660	924	1	1	Coal
WV-3	1	0	1	0			
WV-4	3	0	3	0			
WV-5	1	0	1	0			
WYO-1	536	446	536	446	0	1	Coal
Grand Total	9,824	11,873	9,824	11,873	1	1	
	All Units		HLH	LLH			
	% of Hours (Outages)		45.28%	54.72%			
	% of all hours		56.04%	43.96%			
			HLH	LLH			
	Coal Units		8165	10426			
			43.9%	56.1%			