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June 2, 2005

Via Electronic Mail 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 Application for Deferral of Costs and Benefits Due to Hydro Generation Variance
Docket No. UM 1187

Dear Filing Center:

Enclosed please find an original and six copies of the Stipulation Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-captioned Docket.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely,

/s/ Ruth A. Miller
Ruth A. Miller

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Stipulation Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities, upon the parties on the official service in Docket No. UM 1187, shown below, by causing the same to be electronically served, as well as mailed, postage-prepaid, through the U.S. Mail.

Dated at Portland, Oregon, this 2nd day of June, 2005.

/s/ Ruth A. Miller
Ruth A. Miller

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1187

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In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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Application for Deferral of Costs and Benefits Due to Hydro Generation Variance.	)
	)
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STIPULATION TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 2, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who filed testimony in Oregon Public Utility Commission ("OPUC" or the "Commission") Docket No. UE 165, which is a proceeding that is related to this Docket. My qualifications are attached as Exhibit ICNU/101.

I. INTRODUCTION

Q. WHAT IS THE PURPOSE OF THIS STIPULATION TESTIMONY?

A. The purpose of this testimony is to address the stipulations between Commission Staff and Portland General Electric Company ("PGE" or the "Company") filed in Docket Nos. UE 165 and UM 1187. In addition, I will address the testimony submitted by Staff and PGE in support of the stipulations in UE 165 and UM 1187.

Q. VERY BRIEFLY DESCRIBE UE 165 AND UM 1187.

A. PGE filed a request in UE 165 on May 18, 2004, seeking approval of a Hydro Generation Adjustment ("HGA") tariff that, according to PGE, "tracks the costs and value associated only with hydro generation assets and contracts." Advice No. 04-11, Hydro Generation Adjustment at 3 (May 18, 2004). In that case, parties filed two rounds of direct and rebuttal testimony discussing the merits of the HGA.

PGE filed a request in UM 1187 on December 30, 2004, seeking authorization to defer "excess" costs related to an alleged hydro generation deficit in 2005. Re PGE, OPUC Docket No. UM 1187, Application at 1 (Dec. 30, 2004).

PGE's initial application in UM 1187 requested that the Commission authorize deferred accounting as a means of implementing the HGA effective January 1, 2005. Id. On January 21, 2005, PGE submitted an amended application requesting that the Commission authorize deferred accounting regardless of whether the Commission approved the HGA. Re PGE, OPUC Docket No. UM 1187, Amended Application at 2 (Jan. 21, 2005).

On April 11, 2005, PGE and Staff filed separate stipulations in UE 165 and in UM 1187. It appears that Staff and PGE intend that the stipulations be read together to resolve all issues in both Dockets.

Q. COMPARE THE STATE OF THE RECORDS IN UE 165 AND UM 1187 AT THE TIME PGE AND STAFF FILED THE STIPULATIONS.

A. In UE 165, the record was well developed. The parties had presented a number of issues to the Commission, and there were competing viewpoints regarding the need for and design of an appropriate HGA. In UM 1187, however, there was no evidence in the record at the time the stipulation was filed. There had been no testimony filed, little or no discovery conducted, and no informal workshops or other meetings had been held. The only evidence in the record in UM 1187 at this point is the testimony supporting the stipulation.

Q. HOW DO THE STIPULATIONS RESOLVE THE ISSUES IN THE TWO CASES?

A. Although there are two separate stipulations in UE 165 and UM 1187, both deal with the same subject matter, so I will refer to them collectively as the "the Stipulation." The Stipulation creates a Power Cost Adjustment ("PCA") mechanism that is fundamentally different from anything that was discussed on the record in UE 165. Staff and PGE propose to create a System Dispatch Power Cost Adjustment Mechanism ("SD-PCAM") and request that the SD-PCAM become effective *retroactive* to January 1, 2005, and remain in effect through 2006. Despite the fact that PGE's initial request in UE 165 was for approval of a tariff that would result in recovery of costs related to hydro variability only, the SD-PCAM would result in recovery of cost variations due to: 1) variation in hydro generation; 2) fluctuation in gas prices; and 3) fluctuations in wholesale electric prices. In order to implement the mechanism, PGE will be required to develop a substantially adjusted Monet model run that uses a mix of actual and projected input data to be used in determining the balance of the "System Dispatch Cost Variance" ("SDCV") deferred account. The Commission would decide at an unspecified later date the amortization schedule for any SDCV deferral; however, because the Stipulation provides that the SD-PCAM is an "automatic adjustment clause," it appears there be will no detailed review of development of the SD-PCAM Monet model run or the calculation of the deferral balance prior to amortization.

The SD-PCAM would have a deadband of plus $15.0 million and minus $7.5 million. Deferrals outside of the deadband would be subject to an earnings test and an 80/20 sharing mechanism. As I describe the SD-PCAM more fully elsewhere in this testimony, I will not further elaborate on the details at this point.

The Stipulation also requires PGE to fund a consultant's study of ways to improve the Monet model in the future, and Staff and PGE agree to use a forthcoming rate case as the forum to discuss a permanent PCA.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE STIPULATION?

A. I recommend the Commission reject the Stipulation in its entirety and dismiss both the UE 165 and UM 1187 proceedings for the following reasons:

1. Approval of the SD-PCAM retroactively to January 1, 2005, would constitute retroactive ratemaking. The SD-PCAM provides for recovery of cost variations due to fluctuations in electric and gas prices regardless of whether any variation in hydro generation occurs. This is a broader scope than the "hydro only" deferred account requested by PGE. Even if the Commission approves the SD-PCAM, under no circumstances should it authorize PGE to implement that mechanism retroactively;

2. The Commission decided in Docket No. UM 1071 that deferred accounting was inappropriate for hydro variations and financial impacts of the magnitude that PGE has experienced in 2005;

3. The proposed resolution in the Stipulation does not fall within the range of outcomes supported by the evidence in the record in UE 165;

4. The deadband and sharing mechanism in the SD-PCAM is without analytical support and is inconsistent with the deadbands and sharing mechanisms adopted by the Commission in the past; and

5. PGE's and Staff's request for approval of the SD-PCAM requires the Commission to accept substantial modeling changes that are incomplete and unproven at this time. Moreover, because the SD-PCAM is an automatic adjustment clause, the opportunity to review the appropriateness of the model changes and the accuracy of the calculation produced by those changes will be limited.

If the Commission rejects the Stipulation and PGE or Staff still desire to implement a HGA or PCA, that issue can be litigated in the general rate case that PGE has stated it intends to file by the end of the year. If the Commission does not desire to dismiss the case, but seeks an alternative solution to PGE's hydro generation situation, ICNU's alternative proposal for an extreme event "hydro hedge" tariff is still a viable option. See Re PGE, OPUC Docket No. UE 165, ICNU/100, Falkenberg/29-32 (Feb. 14, 2005).

II. DISCUSSION

Retroactive Ratemaking

Q. THE STIPULATION WOULD ALLOW PGE TO APPLY THE SD-PCAM RETROACTIVE TO JANUARY 1, 2005. WOULD THIS RESULT IN RETROACTIVE RATEMAKING?

A. Absolutely. This is the first major flaw in the Stipulation.

Q. STAFF CONTENDS THAT BY VIRTUE OF THE DEFERRAL APPLICATION FILING MADE BY PGE IN UM 1187, DEFERRAL OF SD-PCAM COSTS IS PERMISSIBLE AND NOT RETROACTIVE RATEMAKING. EXPLAIN WHY YOU DISAGREE.

A. The retroactive ratemaking aspects of the Stipulation are comparable to those raised by Staff's proposed PCA in UE 165. I addressed the retroactive ratemaking issues related to Staff's proposed PCA in my rebuttal testimony in UE 165, which is attached as Exhibit ICNU/102. ICNU/102, Falkenberg/11-14. Those arguments are equally applicable here.

Q. PROVIDE A FOUNDATION FOR YOUR COMMENTS CONCERNING RETROACTIVE RATEMAKING.

A. PGE's initial application for deferred accounting in UM 1187 requested the permission to defer specific costs related to an expected shortfall of hydro generation:

> Pursuant to ORS 757.259 and OAR 860-027-0300, [PGE] hereby requests authorization to defer for later ratemaking treatment *certain costs or revenues associated with variation in hydro generation* from the levels assumed for purposes of establishing rates in UE 161. Pending before the Commission is Docket UE 165, regarding PGE's proposed Schedule l28, a Hydro Generation Adjustment. PGE makes this request to preserve the positive or negative variance in the Deferral Period for treatment either under Schedule 128, or in some other manner as decided by the Commission in this docket or docket UE 165.

OPUC Docket No. UM 1187, Application at 1 (emphasis added).

In its amended application for deferred accounting, PGE was quite specific in its request for deferral of hydro-related costs only, and the Company even proposed a specific method for calculating these costs:

> PGE proposes to establish a new account, the Hydro Generation Balancing Account ("HGBA"). The HGBA is described in more detail in the attached proposed Schedule 128. PGE will defer into the HGBA the hydro generation cost variance ("HGCV") (the "Deferred Amount") as that term is defined in Schedule 128. The HGCV tracks the market value of the difference in hydro generation between the baseline amount set in PGE's annual [resource valuation mechanism ("RVM")] process and actual hydro generation. The variation in generation from the baseline, after application of a deadband and valued at the market index price, will be added to a balancing account.

OPUC Docket No. UM 1187, Amended Application at 2 (internal citation omitted).

Both the original and the amended applications for deferral discuss PGE's view of the necessity of deferring costs related to variations in hydro generation conditions. Neither application discussed or requested permission to defer costs *unrelated* to hydro conditions, including costs due to changes in wholesale electric prices and natural gas prices. In short, under the method for calculating the balance of the deferred account originally requested by PGE, there would be no balance unless there was a variation in hydro generation.

The Commission might reasonably allow PGE to compute the deferral of hydro-related costs in a different manner than proposed by the Company (as noted by the Company itself in the original application quoted above). However, it cannot allow deferral of costs *unrelated* to hydro variations without engaging in retroactive ratemaking.

Q. DOES THE STIPULATION ALLOW FOR DEFERRAL OF COSTS UNRELATED TO HYDRO VARIATIONS?

A. There is no question that it does. Even OPUC Staff witness Mr. Galbraith admits this is the case:

> Q. CAN THE MONET UPDATE METHODOLOGY RESULT [IN] A COST VARIANCE EVEN IF ACTUAL HYDRO CONDITIONS TURN OUT TO BE NORMAL?
>
> A. Yes. Even if normal hydro conditions were to actually occur, the MONET update methodology could still produce a positive, or negative, SDCV due to changes in market energy prices.

Re PGE, OPUC Docket No. UE 165, Staff/300, Galbraith/6 (Apr. 18, 2005). PGE also acknowledges that the SD-PCAM is broader in scope than the hydro-only mechanism the Company originally requested: "The [SD-PCAM] considers not only the value of deviations in PGE's hydro production from expected levels assumed in the RVM process, but also the value gained or lost from the redispatch of PGE's thermal plants, given electric and gas prices that also vary from levels assumed in the RVM process." Re PGE, OPUC Docket No. UM 1187, PGE/100, Dahlgren-Tinker/6 (Apr. 18, 2005).

This acknowledgment of the expanded scope of the SD-PCAM is ironic, because Mr. Galbraith testifies in UM 1187 that the Commission has the discretion to authorize PGE to defer hydro-related costs, but he does not contend that the Commission has the discretion to authorize deferred accounting for costs that are unrelated to variations in hydro conditions. Instead, he argues that the Commission has the authority to adopt a *method* for calculating the deferred account balance that differs from the method originally requested by PGE:

> Q. DOES THE COMMISSION HAVE THE ABILITY TO CONDITION THE GRANT OF A DEFERRAL APPLICATION SO AS TO MORE ACCURATELY CAPTURE THE COSTS AND BENEFITS OF THE UNDERLYING EVENT?
>
> A. Yes. As I indicated in my direct testimony, Staff believes the Commission *has the discretion to authorize PGE to defer costs related to variation in its hydro generation* in a manner that will most accurately capture the costs and benefits associated with that variation. The Commission is not obligated to accept PGE's proposed method for capturing those costs, which is the Hydro Adjustment Tariff originally proposed by PGE. Rather, it has the discretion to select an alternate method for determining the costs and benefits associated with hydro generation variation.

Re PGE, OPUC Docket No. UM 1187, Staff/102, Galbraith/15 (Apr. 18, 2005) (emphasis added).

Setting aside the issue of the Commission's discretion for a moment, Staff's attempt to distinguish the *method* of determining the costs to be deferred from the actual costs that are deferred misses the point. Regardless of whether the Commission has discretion to adopt a different method to establish a "hydro only" deferred account as originally requested by PGE, the Commission cannot authorize a deferred account that is not "hydro only" unless the Company has requested such a deferral. Although Staff attempts to characterize the SD-PCAM as merely a different method to calculate the deferred account balance, it is the SD-PCAM itself that is the problem, because it will result in a deferral balance (due to variations in natural gas and wholesale power prices) even if hydro conditions are normal.

Q. EXPLAIN HOW THE SD-PCAM WOULD ALLOW DEFERRAL OF COSTS UNRELATED TO HYDRO VARIATIONS.

A. The use of a Monet backcast allows actual gas and power prices to be used in addition to actual hydro generation levels. Because the baseline Monet run has substantial amounts of gas and wholesale purchased power included in the run, any subsequent changes in gas and power prices will change the final Monet model results. This change in cost, whether positive or negative, will result in deferral of a cost unrelated to hydro variations. As Mr. Galbraith has testified, even if hydro conditions were exactly as assumed in the final 2005 RVM study, changes in gas or wholesale power prices would produce a cost variance. As a consequence, the SD-PCAM really rests on a mechanism that defers cost variations due to three causes: 1) hydro generation; 2) gas prices; and 3) wholesale power prices. However, PGE requested authorization to defer costs due to hydro variations *only*, not cost variations due to changes in gas and power prices. Thus, Staff and PGE are proposing the Commission allow ultimate recovery of costs for which no deferral mechanism has ever been requested. This clearly would be retroactive ratemaking if the Commission authorized recovery of those costs in rates.

In addition, the Staff and PGE proposal also is troubling because in negotiating PGE certainly had prior knowledge of the impact of allowing retroactive deferrals to take place. This raises questions about the fairness of the negotiation when one party had much more knowledge of the relevant facts than the other parties. Further, from a policy perspective, the negotiation is tainted because one or more of the parties may have negotiated a settlement based on its expected results, rather than with an eye towards the mechanism that provided the best solution to the issues in the case.

Q. COULD YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES THE INEQUITY OF THIS APPROACH?

A. One example might be if the Commission decided to implement a generation performance incentive mechanism. Such mechanisms have been used by regulatory commissions to provide incentives to reduce generator outage rates. Without going into depth regarding the merits of such mechanisms, it is reasonable to assume that the utility should have an equal chance of earning rewards as penalties.

If, however, the Commission decided to institute such a program retroactively right after a major unit outage, any impartial observer would have to question the fairness of that mechanism. Conversely, if a utility requested retroactive implementation of such a program after a period of outstanding generator availability, one might certainly complain that the company was asking for a "gift." In neither case would a retroactively applied program be a fair regulatory policy because to a certain extent the party would be rewarded or punished for past circumstances it had no ability to change. Good regulatory policy would not operate in a manner that implements one-sided policy changes. As in the case of gas and power price variations, it is not proper to provide a financial incentive to PGE (or conversely a penalty) for events unrelated to hydro variation that have already happened.

Q. IS IT POSSIBLE THAT THE COMMISSION COULD ACCEPT THE SD-PCAM BECAUSE IT BELIEVED IT WAS A MORE ACCURATE METHOD FOR COMPUTING COSTS DUE TO HYDRO VARIATIONS?

A. Yes. As Mr. Galbraith has pointed out, the Commission could use a different methodology than proposed by PGE to compute costs due to hydro variations. It might even use a method requiring use of the Monet model instead of the Dow Jones index. However, with respect to events that occur prior to any Commission approval of the SD-PCAM or another method, the Commission's discretion should be limited to methods that deal with hydro cost variations alone. While it may not be possible to enumerate all of the methods the Commission might consider, one element must be common to all reasonable methods: *if there is no hydro generation variation between actual and forecast, whatever method used should result in zero deferred costs.* This is an acid test that distinguishes between an allowable method and one that is not allowable for any mechanism that the Commission intends to implement retroactively to January 1, 2005. By Mr. Galbraith's own admission, the SD-PCAM fails to meet this requirement. Instead of allowing deferral of only one cost (hydro variation), the proposal allows deferral of two unrelated costs (gas and power price variations) as well.

Q. IS IT POSSIBLE THAT THE POWER PRICE VARIATIONS ARE RELATED TO HYDRO VARIATIONS, I.E., COULD HYDRO VARIATIONS ACTUALLY "DRIVE" GAS PRICE VARIATIONS?

A. Market prices for power are driven by many factors and hydro is only one minor influence. The regional supply of hydro certainly impacts regional supply and demand, which impacts power prices. However, power prices are also affected by many other factors, included load variations, weather, general economic activity, gas and oil prices, plant outages, and construction of new resources. At the very best, hydro is one of many drivers of regional power prices. There is no evidence that hydro has any measured or even measurable impact on regional power prices. This again was discussed in my direct testimony in UE 165, and never contradicted elsewhere.

Gas prices also are driven by many factors, including the worldwide supply and demand for oil, the national economy, weather, and a myriad of other factors. There is nothing to suggest that gas prices are impacted in any meaningful or measurable way by regional hydro conditions.

Q. HAVE THERE BEEN OTHER CASES WHERE A UTILITY COMMISSION DENIED A REQUEST FOR DEFERRAL BASED ON RETROACTIVE RATEMAKING CONCERNS?

A. Yes. PacifiCorp filed two cases in Wyoming (Docket No. 20000-EP-01-167, a request for a PCA, and Docket No. 20000-ER-00-160, a request to defer excess power costs) related to the Western Power Crisis in 2000 to 2001. In its application for deferral, filed on November 1, 2000, PacifiCorp requested to "defer with interest certain excess net purchased power costs it incurred, consisting of extremely high wholesale purchased power costs of what it terms an "unprecedented" nature which were substantially higher than the net power costs then factored into its existing Wyoming retail electric utility rates." Re PacifiCorp, Wyoming Public Service Commission Docket Nos. 20000-EP-01-167 and 20000-ER-00-160, Order Granting Motion to Exclude Hunter Generator-Related Costs from Case at 1 (Nov. 9, 2001). Subsequent to filing the request, in late November 2000, PacifiCorp's Hunter unit 1 generator failed, resulting in an outage that lasted more than five months. Early in 2001, PacifiCorp filed a request to implement a PCA to recover the deferred excess power costs. PacifiCorp acknowledged during the course of these cases that its calculation of excess power costs included costs related to the Hunter outage as well as costs related to the power crisis.

One of the intervenors in the Wyoming cases, the Wyoming Industrial Energy Consumers ("WIEC"), filed a motion to exclude the Hunter outage costs on the basis of retroactive ratemaking. WIEC contended that:

> [T]he Hunter costs were not properly or adequately made a part of the case, and that to allow inclusion of the costs in this case would constitute prohibited retroactive ratemaking. WIEC argued that the accounting application and order did not contemplate the inclusion of the Hunter costs and that those costs represented a quantum shift in the magnitude and the character of the case before us, accounting for perhaps two thirds of the $46.8 million being sought, greatly exceeding the amount originally estimated by PacifiCorp and vastly enlarging the number and scope of issues to be considered.

Id. at 3. WIEC argued that the original deferral application was limited to excess purchased power expenses and obviously made no mention of the Hunter deferral. Ultimately, the Wyoming Commission granted WIEC's motion to remove Hunter outage costs from the proceeding.

The similarities between the Wyoming cases and the instant proceedings are substantial. Both instances involved a request for deferral and a related request for implementation of a PCA mechanism. In both instances, the utility ultimately sought to recover a blended collection of costs stemming from higher market prices for power and higher costs from a generation deficit. In both cases, elements of retroactive ratemaking were present because the deferral application never requested deferral of some of the costs whose recovery was later sought in the PCA mechanism. Consequently, the Wyoming proceeding offers a valid reference point for the Oregon Commission to consider.

Q. BASED ON THE INFORMATION CONTAINED IN PGE'S RESPONSE TO ICNU DATA REQUEST NO. 8.2, IT APPEARS THAT GAS PRICES ARE NOW LOWER THAN FORECASTED IN THE FINAL MONET RUN USED IN RVM 2005. DOES THIS UNDERMINE YOUR ARGUMENT REGARDING RETROACTIVE RATEMAKING?

A. No. The prohibition against retroactive ratemaking is a two-way street. Whether it reduces or increases the deferral balance, it should not be allowed. Further, given the unequal availability of information to the negotiating parties, PGE may well have been able to negotiate a better settlement for itself because it had better knowledge of the changes in gas and power prices to date.

Q. COULD THE COMMISSION REQUIRE THE STIPULATION TO BE CHANGED SO THAT THE RETROACTIVE RATEMAKING CONCERNS ARE ELIMINATED?

A. This is not a practical solution, as the stipulating parties negotiated the settlement as an integrated agreement. Further, it is not clear how the Commission might accomplish this goal or what a settlement free of retroactive ratemaking concerns might have entailed. Even if the Commission were convinced that the SD-PCAM provides a fair solution to the issues regarding hydro variability, it should only apply that mechanism prospectively, due to the retroactive ratemaking concerns that exist otherwise. However, there are more compelling reasons why the Commission should reject the Stipulation completely, as I will now discuss.

<u>UM 1071 Precedent</u>

Q. PUTTING ASIDE THE RETROACTIVE RATEMAKING ISSUE, IS THE STIPULATION CONSISTENT WITH THE UM 1071 PRECEDENT?

A. No. This is a second major flaw in the Stipulation. In effect, the Stipulation would grant the request for deferral in UM 1187 even though the Commission flatly denied a similar request for deferral of hydro cost variances in UM 1071. For the Stipulation to provide a reasonable outcome of UM 1187 and UE 165, it requires one to assume that the Commission would grant the deferral request. The precedent in UM 1071 suggests that was an unlikely outcome of UM 1187.

In UM 1071, an entirely analogous set of circumstances as in UM 1187 was presented to the Commission. In that case, PGE requested permission to defer costs related to hydro variations during 2003. In denying the deferral request, the Commission found that hydro cost variations were a "stochastic risk" and therefore inappropriate costs for purposes of a deferral mechanism:

> We agree with Staff that risks normally included in modeling power costs (stochastic risks) are not appropriate for deferred accounting, as long as those risks are reasonably predictable and quantifiable and have no substantial financial impact on the utility. Here, hydro variability has been included and modeled to set PGE's base rates. The hydro year on which PGE bases its application is, as CUB points out, a 1 in 4.5 year event. This cause is not extraordinary enough to justify deferred accounting.

<u>Re PGE</u>, OPUC Docket No. UM 1071, Order No. 04-108 at 9 (Mar. 2, 2004).

Q. WAS THE COMMISSION'S DECISION IN UM 1071 WELL FOUNDED?

A. Yes. The Order was very well reasoned, providing no basis for assuming that it does not apply to the deferred accounting request at issue in UM 1187. The Commission was correct to recognize that "stochastic risks" are already addressed in setting normalized rates. The recognition of hydro variability as a stochastic risk is important because the Commission already allows for recognition of variations in hydro generation levels via its normalization of net power costs. In Monet, the Company uses a sixty-year average of hydro conditions to develop normalized power costs. For this reason, the likelihood of both good and bad hydro conditions is already reflected in rates, and granting of a deferral in a poor hydro year would amount to double recovery.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THIS?

A. Table 1 presents a hypothetical example to explain this problem. In the example, the utility uses a power cost model to compute normalized power costs on the basis of five different hydro generation scenarios.[1/] The table shows a hypothetical company that has an average of 700 MW of hydro and replacement power costs $50/MWh. It shows that under normalized ratemaking customers are charged $600 million per year as the average cost of power based on average hydro over a five-year period (simplified from sixty years, which is actually what is used). Over five years, the results would all average out and customers would pay what power actually costs, $3.0 billion. The $3.0 billion figure includes both good and bad hydro years. The normalized cost of $600 million is lower than the cost of power in below average hydro years, but higher than the cost of power in good hydro years. By using the average value, a “premium” is built into the

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[1/] PGE actually averages the hydro inputs in Monet in a single run, rather than performing a multiple water year run. However, the use of this approach is not conceptually different from the method shown in the table.

normalized cost of power in good years that provides a form of "insurance" against bad hydro years.

Assume now that year five is the worst hydro year and the utility requests a deferral to allow it to ultimately recover the additional power costs. If regulators allow the utility to have a deferral in a bad hydro year, it gets the benefit of the "premium" built in during the good years, and then effectively charges the actual cost in year five. Under this scenario, ratepayers pay the normalized cost of power ($600 million) for the first four years and the actual cost of power in year five. The total cost of power to customers in that scenario is $3.044 billion, resulting in an overcharge to customers of $44 million.

Table 1
Example of Overcollection Problem
(millions of dollars)

Year	Hydro (aMW)	Net Power Costs	Normalized Ratepayer Cost	Ratepayer Cost With Deferral in Year 5
1	800	$556.2	$600.0	$600.0
2	750	$578.1	$600.0	$600.0
3	700	$600.0	$600.0	$600.0
4	650	$621.9	$600.0	$600.0
5	600	$643.8	$600.0	$643.8
Average	700	$600.0	$600.0	
Total Ratepayer Cost		$3,000.0	$3,000.0	$3,043.8
			Overcollection	$43.8

In the example above, the higher than normal costs of a bad hydro year ($43.8 million) are averaged into rates every year. However, instead of getting a "free pass" when the bad hydro year actually arrives, customers are now required to pay for bad hydro conditions as well. When above normal hydro conditions occur, customers pay the normalized cost and the utility keeps the savings. When below normal hydro conditions occur, the utility changes the rules of the game and asks for recovery of the total cost. So this is a "heads I win, tails you lose" type of hydro normalization that should not be allowed by regulators. The Commission was wise to have recognized this problem in UM 1071. It should not abandon its reasoning from UM 1071 in this case.

Q. IT MIGHT BE SUGGESTED THAT INSTITUTION OF THE SD-PCAM WOULD MITIGATE THE PROBLEM OF UNEQUAL TREATMENT IN GOOD AND BAD HYDRO YEARS BY DEVELOPING A PREDETERMINED TREATMENT OF HYDRO COST VARIATIONS. DO YOU AGREE?

A. No. First, this regulatory change is being suggested in a year in which the utility already expects poor hydro conditions to prevail. Thus, the mechanism virtually assures PGE of a positive recovery balance in year one. Further, without a deferral, PGE is now earning well below its regulated rate of return. As a result, even if hydro conditions were to improve dramatically in the months ahead, there is very little chance ratepayers would benefit from a negative deferral due to the earnings test contained in the Stipulation. This would be comparable to placing your bet in a casino after the roll of the dice is known. For the approach to be fair, it can only be applied on a prospective basis where there is no reason to expect the initial experience would differ from the long-term average.

Second, the SD-PCAM is only a temporary mechanism. After two years, it may be replaced by some other (as yet unknown) mechanism or there may be no mechanism at all. There is nothing to require PGE to seek a PCA in the future should hydro conditions suddenly appear more favorable. For the SD-PCAM to be a fair solution, it would have to be in effect long enough so that ratepayer benefits in good hydro years would balance out with the expected high cost in the first year. The SD-PCAM, however, would only be in effect through 2006. Recall that Mr. Galbraith testified that revenue neutrality was a desirable goal for a PCA mechanism in his direct testimony in UE 165. Re PGE, OPUC Docket No. UE 165, Staff/100, Galbraith/12 (Feb. 14, 2005). Allowing implementation of the SD-PCAM after it is known to produce a positive cost variance in the very first year is inequitable. This, of course, is yet one more reason why it should not be implemented retroactive to January 1, 2005.

Q. WERE THE HYDRO CONDITIONS AT ISSUE IN UM 1071 COMPARABLE TO CURRENT HYDRO CONDITIONS?

A. Yes. In UM 1071, the Commission found that the then expected hydro deficit amounted to a one in 4½-year event. OPUC Docket No. UM 1071, Order No. 04-108 at 9. In this case, the Company now estimates that the hydro deficit will result in a generation shortfall of 568,000 MWh. OPUC Docket No. UM 1187, PGE/100, Dahlgren-Tinker/3. Exhibit ICNU/103 demonstrates that based on the sixty years of hydro data used in computing normalized power costs, the current hydro deficit is a one in five year event. ICNU/103, Falkenberg/1-2. Thus, it does not differ materially from the deficit level the Commission found beneath its materiality threshold in UM 1071:

> We agree with Staff that risks normally included in modeling power costs (stochastic risks) are not appropriate for deferred accounting, as long as those risks are reasonably predictable and quantifiable and have no substantial financial impact on the utility. Here, hydro variability has been included and modeled to set PGE's base rates. The hydro year on which PGE bases its

> application is, as CUB points out, a 1 in 4.5 year event. This cause is not extraordinary enough to justify deferred accounting.

OPUC Docket No. UM 1071, Order No. 04-108 at 9.

Q. DOES THE STIPULATION DEPART FROM THE PRECEDENT SET IN UM 1071 IN OTHER WAYS?

A. Yes. In UM 1071, the Commission also determined that an event that represents a stochastic risk must have a "substantial" financial impact on the utility:

> The magnitude of the financial effect on the utility is also a factor in our consideration under the discretionary stage of the decision process. For a stochastic risk to justify deferred accounting, the financial impact must be substantial. Although we decline to set a numerical criterion, we can give negative and positive examples. In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business. In the Idaho Power cases, discussed below, we allowed partial recovery for a financial impact that represented approximately 700 basis points of Idaho Power's return on equity.
>
> * * *
>
> In the present application, PGE claims that it has incurred $31.6 million in excess NVPC, only some of which is attributable to hydro replacement costs. PGE asserts that this excess NVPC amounts to 172 basis points of return on equity. This is well short of the 250 basis points of return on equity within which we allowed no recovery in UM 995.

<u>Id.</u>

While the Commission did not articulate a hard and fast standard, it is clear that it considered an impact within a 250 basis point deadband inadequate in the PacifiCorp case, and that PGE's projected hydro variance of $31.6 million was inadequate in UM 1071.

Q. HOW DO THESE STANDARDS RELATE TO THE INSTANT CASES?

A. Based on PGE's UM 1187 testimony, the Company estimates the current cost of the hydro deficit to be $30 million. OPUC Docket No. UM 1187, PGE/100, Dahlgren-Tinker/3. Obviously this differs little from the projection in UM 1071, and falls well short of the 250 basis point deadband adopted in the PacifiCorp case. This implies strongly that the Commission should deny the request for deferral in UM 1187 on the same basis as it denied the request in UM 1071. Further, there is the strong implication that the SD-PCAM deadband (which is far less than 250 basis points) is also inconsistent with the precedent of UM 1071.

Q. CAN YOU TIE ALL THESE POINTS TOGETHER?

A. The Stipulation requests that the Commission authorize a deferred account that is broader than PGE's application in UM 1187. The Commission set a precedent in UM 1071 that suggests it should deny the UM 1187 deferral application because: 1) hydro variability is a stochastic risk; 2) the particular level of hydro variability experienced in 2005 was contemplated when power costs were set in PGE's last RVM proceeding; 3) the financial impact of this variance in hydro conditions is not "substantial;" and 4) the SD-PCAM has a deadband and sharing mechanism that is inconsistent with the Commission's stated views in UM 1071. This is a serious flaw in the Stipulation as it runs contrary to existing Commission precedent.

Other Issues

Q. ARE THERE OTHER REASONS WHY YOU BELIEVE THAT ACCEPTING THE STIPULATION WOULD PRODUCE A POOR RESULT FROM A POLICY PERSPECTIVE?

A. Yes. The Stipulation would resolve two separate cases in which the records were in very different states at the time the Stipulation was filed. In UE 165, there had been two rounds of testimony and the record was fairly complete at the time PGE and Staff executed the Stipulation. In UM 1187, however, there had been no discovery and no testimony or other evidence presented. Thus, the record in UM 1187 was very limited at the time the Stipulation was filed. For this reason, any settlement was premature. The Commission's order in UM 1071 made clear that authorization of a deferred account is a factual matter and that evidence was required to demonstrate the type of event underlying the deferral and the magnitude of the financial impact. OPUC Docket No. UM 1071, Order No. 04-108 at 8-9. Given the similarity of the facts in UM 1187 and UM 1071, it appears that parties were "overly anxious" to settle the case. While it is certainly understandable that PGE would wish to settle the case, Staff's agreement is quite puzzling. This is particularly true when one considers that Staff had opposed the comparable PGE deferral request in UM 1071, and that the Commission agreed with Staff in that case.

Q. DOES THE SD-PCAM ADDRESS PGE'S ALLEGED HYDRO VARIABILITY PROBLEM IN A MANNER THAT IS SUPPORTED BY THE RECORD IN UE 165?

A. No. This is another serious defect in the Stipulation. Settlements make sense in a regulatory setting when parties develop compromises that are consistent with the possible outcomes supported by the record of evidence. For example, if PGE requested a ROE of 11% in a general rate case and Staff recommended 10%, any figure within that range could be considered as supportable from the evidence. If the parties were to agree on 10.5% ROE, that would certainly provide a compromise consistent with the record in the case.

Likewise, one could easily imagine a case where there was a dispute on revenue allocation, with one party proposing a 10% industrial increase, but none for any other class, while another proposed a 10% residential increase, but none for any other class. If the parties settled on a 5% increase for both classes, that would represent a compromise within the range of the outcomes contained in the record of evidence.

In UE 165, however, the compromise on the SD-PCAM is not similar to anything advocated on the record in the case. Indeed, that mechanism differs substantially from all of the proposals made by the parties. This would be akin to the revenue allocation dispute referenced above being settled by the parties agreeing to a "compromise" where classes not represented in the case (e.g. commercial) were assigned a 10% increase, but no increase was adopted for any other class. In that case, the compromise would clearly be outside of the range of outcomes supportable by the evidence, and the Commission would be unwise to adopt it.

In this case, no party proposed a solution appearing remotely similar to the SD-PCAM. PGE presented the HGA, a mechanical application of the wholesale market index to hydro generation variances. ICNU and CUB opposed the HGA, although ICNU suggested a "hydro hedge" concept as an alternative. Even Staff, who presented a comprehensive, extreme event PCA did not propose a mechanism comparable to the SD-PCAM. While the PGE and ICNU proposals would have dealt only with hydro variations in a formulistic approach, Staff's proposed PCA relied on actual costs. In contrast, the SD-PCAM relies on the Monet model rather than a formulistic approach and it ignores actual power costs. This is a radically different solution than anything proposed on the record in UE 165.

Q. WHY IS IT A PROBLEM THAT THE SD-PCAM IS NOT SUPPORTED BY THE RECORD IN UE 165?

A. Had the SD-PCAM concept been introduced into the record in the case, it would have been possible for parties to study it in more detail, and possibly test its validity. Potential flaws and problems in the approach might have been uncovered and perhaps substantial improvements could be made in the methodology. The introduction of the SD-PCAM at this late stage denies the Commission the opportunity to fully examine the concept and how it might best be applied. This is particularly troubling because, as described below, implementation of the SD-PCAM is requiring PGE to develop a substantially modified Monet model run that the Company has not yet completed, and it appears that, if there is any future review of the changes to the model or calculations of the deferred amounts, it will be limited.

This also is troubling because Staff had discussed the concept of a hydro-related PCA based on Monet Backcast studies in UM 1071, and the Commission expressed some interest in it in the final order in that docket. OPUC Docket No.

UM 1071, Order No. 04-108 at 5-6, 10-12. Given this history, the record would have been much better served if Staff had proposed the concept in its initial round of testimony. Instead, Staff proposed a full PCA, which was far outside the boundaries of a case filed by PGE to address hydro variability. This was discussed in depth in my rebuttal testimony in UE 165.

Q. ARE THERE OTHER PROBLEMS WITH THE SD-PCAM METHOD?

A. As noted above, this method as proposed will allow PGE to defer (and ultimately collect) costs related to gas and power price changes. In UE 165, neither the Company, nor ICNU proposed a mechanism intended to allow deferral of anything except hydro costs. Thus, the Stipulation provides for deferral of costs never previously requested by the Company.

Q. DO YOU HAVE ANY COMMENTS CONCERNING THE DEADBAND USED IN THE STIPULATION?

A. Yes. I am concerned that there is no analytical support for the proposed deadband. While Mr. Galbraith proposed that a PCA mechanism should be revenue neutral, there has been no evidence offered to demonstrate that the proposed deadband will assure revenue neutrality.

Q. IS THE SHARING MECHANISM CONSISTENT WITH PAST COMMISSION PRACTICE?

A. No. The sharing mechanism is far more generous than those adopted in the past by the Commission. In UM 995, the Commission required 50/50 sharing on excess power costs between 250 and 400 basis points, and 75/25 sharing above 400 basis points. In the nine and fifteen-month PCAs approved pursuant to the settlement in UE 115, the Commission used a 50/50 sharing for power cost variances between $28 and $38 million per year. The 80/20 sharing percentage in the SD-PCAM is far more generous than the Commission has authorized in the past.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE STIPULATION?

A. Yes. The Stipulation treats the SD-PCAM as an automatic adjustment clause:

> 8. The deferral and amortization of power cost variances described in this Stipulation constitutes an automatic adjustment clause under the terms of ORS 757.210.

<u>Re PGE</u>, OPUC Docket No. UE 165, Stipulation at 4 (Apr. 11, 2005).

ORS § 757.210 defines an automatic adjustment clause as follows:

> The term "automatic adjustment clause" means a provision of a rate schedule which provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred or revenues earned by a utility and which is subject to review by the commission at least once every two years.

In addition, the deferred accounting statute states:

> Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts described in this section shall be allowed in rates only to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral.

ORS § 757.259(5).

The testimony supporting the Stipulation does not discuss any review process or other mechanism for parties to review and challenge the validity of the SD-PCAM deferrals. Based on the definition of an automatic adjustment clause within the statute, it appears that there would be no opportunity for parties to review or present evidence concerning the SD-PCAM calculations. While the

SD-PCAM itself is subject to review every two years, the Stipulation testimony does not address what the review might entail or what the scope of such a review would be. Typically such a review would only amount to a perfunctory analysis to ensure that the tariff is recovering the amount of costs deferred, not a review of the reasonableness of the amount of costs computed.

Q. WHY IS THIS A CONCERN?

A. The use of a computer model such as Monet to derive the power cost variance calculation without any possibility of a hearing is quite troubling. Monet is a very complex model, and PGE is changing the model substantially to permit the calculations required in the SD-PCAM to be computed. Exhibit ICNU/104 is a copy of a number of PGE's responses to data requests in UE 165 in which ICNU asked the Company to identify all of the input data and calculations that will be changed to implement the Stipulation, to explain the changes that will be made to the model, or to provide the actual data that will be used to perform the calculation of the SD-PCAM balance. The Company generally responded that it had not completed the model changes and did not have all the actual data. In addition, PGE indicated in certain responses that ICNU should be able to determine the inputs of the model that will be changed "based on the terms of the stipulation." ICNU/104, Falkenberg/1.

Given the complexity of Monet and the generalized manner in which the Stipulation describes the changes that are necessary, it would be extremely difficult for ICNU to precisely determine all of the input and model changes that must be made to implement the SD-PCAM. Indeed, based on PGE's responses to

ICNU's data requests, it is unclear if PGE has even determined all of the inputs and model changes that must be made, because changing one aspect of the model may result in unanticipated effects on other areas.

For the model changes that the Stipulation does generally describe, those changes are problematic, particularly given the lack of opportunity for review. While Monet uses a monthly gas price now, the SD-PCAM requires a daily gas price. In addition, the methodology for computation of the hourly market price inputs will change in Monet. Under the current method, Monet hourly prices are determined by a forecast of monthly standard product prices applied to an input set of price shapes. Under the new methodology, hourly prices will be based on a daily Mid-C index, shaped with an hourly Mid-C price index. I will discuss some technical concerns with the approach later. However, a basic problem with this approach is the fact that there is likely to be a systematic difference between the input price shapes and hourly Monet (input) price shapes. This could well lead to a change in the SD-PCAM, even if the underlying average monthly market prices did not change at all.

Further, many of the Monet inputs will remain unchanged, but many will be altered. PGE did not identify the specific Monet inputs that will change and indicated that doing so would be a burdensome task. ICNU/104, Falkenberg/1. Consequently, it is not reasonable to consider this a good candidate for an automatic adjustment clause because the calculations are quite complex and not transparent.

Finally, changing the Monet model logic to accommodate the new inputs required in the Stipulation may impact the program itself in some unanticipated way. In essence, PGE and Staff ask the Commission to approve the SD-PCAM on the basis of substantial modeling changes and complex calculations that are incomplete and unproven, which is a substantial concern given that the SD-PCAM is an automatic adjustment clause that will be implemented without any hearing or other opportunity for review. Indeed, there is no language in the Stipulation concerning a review of the Monet model changes or the amounts of deferred costs. Based on this, it appears that Staff has no intention of reviewing or analyzing the deferral amounts. This is a great concern because of the complexity of the calculations involved. While it is unclear whether this reflects the intentions of the parties to the Stipulation, the supporting testimony provides no reason to believe that any review process or hearing will occur. If the Commission does not reject the SD-PCAM altogether, parties should at least have the opportunity to present evidence concerning the changes to the Monet model and the calculations of the power cost variances to be deferred under the mechanism.

Q. IS PGE'S AGREEMENT TO SPEND $100,000 ON A CONSULTANT'S STUDY TO IMPROVE MONET A SUBSTANTIAL CONCESSION?

A. No. The Company should investigate improvements in the model for regulatory purposes as a matter of course. Staff has indicated an interest in stochastic modeling, thus it would make sense for the Company to investigate this option even without the Stipulation. Even if the consultants do identify a way to incorporate stochastic modeling into Monet, it is very difficult to view this as a substantial enough ratepayer benefit to overcome all of the other disadvantages of the Stipulation that I have already discussed.

Q. DOES THE STIPULATION PROVIDE A REASONABLE MEASURE OF EXTRA POWER COSTS INCURRED BY PGE?

A. Based on a comparison of the figures shown in PGE's response to ICNU Data Requests 8.2 and 8.5 in UE 165, the SD-PCAM approach provides for a higher deferral balance for the period January to March 2005 than PGE's actual power cost variance. While the power costs reflected in rates are $7.0 million less than actual costs for January to March 2005, PGE has indicated that the SD-PCAM would defer $11.1 million during that period. ICNU/105, Falkenberg/2. The latter figure is based on PGE's best approximation of the results of the SD-PCAM deferral, without any deadband. Consequently, for at least the first three months of 2005, the Stipulation would allow PGE to defer costs in excess of its actual recovery shortfall. This illustrates the problem with allowing deferral of a single cost element, such as hydro, when the overall cost picture is much more complex. It also illustrates that the financial impact of PGE's alleged power cost recovery deficit is overstated, and provides additional justification to deny the UM 1187 deferral.

<u>**Galbraith UM 1187 Testimony**</u>

Q. IN UM 1187, MR. GALBRAITH TESTIFIES IN SUPPORT OF THE STIPULATION ON THE BASIS THAT "AN AUTOMATIC ADJUSTMENT CLAUSE IS PREFERABLE TO THE PERIODIC USE OF DEFERRED ACCOUNTING." DO YOU AGREE?

A. No. There may be times when deferred accounting is appropriate. Certainly one would not want to implement an automatic adjustment clause every time a utility encounters an unexpected cost. However, in this case, Mr. Galbraith has "missed the boat" completely because the testimony assumes that deferred accounting is appropriate and justified. The Commission already decided in UM 1071 that it would not allow deferred accounting for stochastic risks such as a hydro deficit. Thus, it is not realistic to view an automatic adjustment clause as the likely alternative to the selective use of deferred accounting.

Q. MR. GALBRAITH TESTIFIES THAT THE SCOPE OF UM 1187 SHOULD LARGELY BE DETERMINED BY THE UNDERLYING CAUSE OF THE DEFERRAL APPLICATION—THE ECONOMIC IMPACT OF VARIATION IN HYDRO GENERATION. DO YOU AGREE?

A. Mr. Galbraith forgets that the Commission already voiced its opposition to such deferrals in UM 1071. Putting that aside, however, I agree with Mr. Galbraith's statement. What puzzles me, however, is why Staff has agreed to support deferral of costs that by Mr. Galbraith's own admission are completely unrelated to the variation in hydro generation.

Q. MR. GALBRAITH TESTIFIES THAT NET POWER COSTS ARE A WELL DEFINED SET OF INTERRELATED COSTS. DO YOU AGREE?

A. No. I am surprised Mr. Galbraith would make this statement given that he testified in UE 165 in favor of changing the very definition of net power costs to include gas resale revenues. OPUC Docket No. UE 165, Staff/100, Galbraith/16-17. This is an item never previously included in power costs that Mr. Galbraith proposed to include in the Staff PCA.

<u>Joint Stipulation Testimony</u>

Q. PGE AND STAFF TESTIFY THAT THE STIPULATION ADDRESSES THE CONCERNS OF ICNU AND CUB CONCERNING THE ROLE OF GAS FIRED GENERATION IN PGE'S RESPONSE TO HYDRO DEFICITS. PLEASE COMMENT.

A. The Joint Stipulation testimony is contradicted by PGE's rebuttal testimony with respect to gas generation. While the Joint Stipulation testimony suggests that use of the Monet backcast method addresses the changes in gas-fired generation resulting from hydro generation variances, PGE argued strongly in its UE 165 rebuttal testimony that Monet has been a very poor predictor of gas generation:

> PGE Exhibit 901 shows differences between actual and expected hydro and gas-fired generation (MWh) on a monthly basis for the 2002-04 period. Expected generation is based on Monet runs for UE-115 and PGE's 2003 and 2004 RVMs. The Exhibit shows no systematic relationship between changes from expectations in PGE's hydro and gas-fired production**.**

<u>Re PGE</u>, OPUC Docket No. UE 165, PGE/900, Lobdell-Niman-Tinker/5 (Apr. 18, 2005). Thus, PGE seems to have proven that Monet does a poor job of predicting changes in hydro and gas-fired production. It appears unwise, under these circumstances, to use Monet to compute the SD-PCAM hydro deferrals using altered gas price assumptions.

Q. DO YOU HAVE ANY COMMENTS CONCERNING THE METHODOLOGY CONTAINED IN THE STIPULATION FOR DEVELOPMENT OF THE ACTUAL POWER PRICE INPUTS FOR MONET?

A. The Stipulation requires that PGE develop hourly price inputs for Monet by spreading daily Mid-C index standard product prices to hours based on the Mid-C hourly price index. This procedure is questionable because if one already has an hourly market price index, there is no reason why it should not be used directly.

There is no reason to believe that this process "improves" the quality of the final result, and there is no reason to believe the daily price indices are superior to the hourly price index.

Q. HAVE YOU COMPARED THE DAILY AND HOURLY PRICE INDICES?

A. Yes, and the results suggest that both data sources are questionable. I compared the average hourly price for each day (to date) in 2005 to the average price for each day in 2005 based on the standard product index. The results demonstrate substantial disparities between the two data series. Because both series represent a measure of daily market prices, one should expect the two to produce equal results on average and exhibit a very high degree of correlation.

Instead, as shown on the table below, the correlation between these data series is erratic and inconsistent at best. For example, in March 2005, the correlation coefficient is only 34%, while for January through March 2005, the correlation coefficient is only 65% overall. Further, as the data shows, the daily Dow Jones index produces prices that are typically $1/MWh higher.

This is troubling because these inconsistent inputs will be used in Monet to develop an artificial actual price for each hour. Rather than simply using the hourly index without adjustment, the Stipulation requires that the daily index will take precedence over the hourly index. Because PGE is a net purchaser and because there is a hydro deficit for 2005, it appears the reliance on the daily index instead of the hourly index will increase costs to customers.

Table 2
Average Daily Mid C Price
Based on Dow Jones Hourly and Daily Standard Product Prices

	Correlation	Hourly	Daily
Jan 1 - Mar 31, 2005	65%	46.51	47.33
Jan-05	74%	45.57	46.32
Feb-05	62%	45.75	45.67
Mar-05	34%	48.14	49.83

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

ICNU/101

Randall J. Falkenberg Qualifications

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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 Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil 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 Power Co.	Cancellation of nuclear

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Georgia Public Service Commission Staff		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.
12/86 613	9437/	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.
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.

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

Date	Case	Jurisdict.	Party	Utility	Subject
10/88 gas	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of 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.
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	Consumers Power	DSM Policy Issues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Businesses Advocating Tariff Equity (ABATE)		
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.
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.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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.
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	Tampa Electric Co.	Polk County Power Plant

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Power Users Group		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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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	CCS	PacifiCorp	Certification of Peaking Plant
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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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	UE-032065	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation
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

ICNU/102

Rebuttal Testimony of Randall Falkenberg
In OPUC Docket No. UE 165

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 165

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Application for Approval of a Hydro Generation Adjustment Tariff.	)
	)

REBUTTAL TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

March 15, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who filed direct testimony in this case.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. The purpose of this testimony is to respond to the recommendations made by Oregon Public Utility Commission ("OPUC" or the "Commission") Staff in its direct testimony regarding Portland General Electric Company's ("PGE" or the "Company") request for approval of the Hydro Generation Adjustment ("HGA") tariff. I agree with Staff's recommendation to reject PGE's HGA proposal; however, I disagree with Staff's proposal that the Commission establish an interim power cost adjustment ("PCA") mechanism for PGE in 2005 and 2006, and a comprehensive, permanent PCA after that time. Consequently, this testimony will delineate the areas of disagreement with the Staff and the reasons for them.

Q. IN THE INTEREST OF CLARITY, COULD YOU IDENTIFY YOUR AREAS OF AGREEMENT AND DISAGREEMENT WITH STAFF?

A. Yes. I agree with many of Staff's comments and recommendations regarding the HGA itself. However, I disagree with Staff's recommendation to implement an "interim" PCA retroactively to January 1, 2005, and I am troubled by Staff's proposal to broaden the scope of the PCA far beyond PGE's limited request for recovery of hydro costs. To be as specific as possible, below I present a grouping of Staff's recommendations to the Commission. After each set of recommendations, I will indicate whether I agree or disagree with it.

Staff Recommendation # 1

- *The Commission should consider reasonable risk reduction, neutral cost recovery, and equal treatment criteria when evaluating automatic adjustment clauses. These criteria are additions to PGE's rate stability, regulatory transparency, and incentive for good management criteria.*

- *The Commission should reject PGE's proposed HGA mechanism. The $2.5 million deadband removes nearly all of PGE's hydro-related earnings risk and fails the reasonable risk reduction criterion. Tracking asymmetric financial impacts with the symmetrically designed HGA mechanism would result in an expected economic windfall for PGE and therefore fails the neutral cost recovery criterion.*

- *The Commission should indicate a preference for Expected Value Power Cost modeling. Modeling the uncertainty associated with retail loads, natural gas and electricity market prices, hydroelectric generation, and thermal unit availability provides a more realistic simulation of PGE's system operations and produces a distribution of NVPC that can be used to design a fair PCA mechanism.*

Staff/100, Galbraith/2. I do not agree that a PCA has been justified on the basis of the record in this proceeding or that a PCA should now be established. This Docket began as an investigation into PGE's very narrow proposal to implement the HGA tariff to track the costs of variations in hydro generation. There is simply no basis to conclude in this Docket that a comprehensive PCA that tracks the costs of variations in all net variable power costs ("NVPC") should be established now.

Staff Recommendation # 2

- *The Commission should indicate a preference for a PCA mechanism with a deadband set: (1) to exclude a reasonable range of normal variation from triggering the PCA mechanism, and (2) to be neutral on an expected recovery basis. For example, a deadband set at the 10th and 90th percentiles of the 'All-in' NVPC* *distribution, as distinguished from the 'Hydro-only' NVPC distribution, would satisfy these criteria.*

- *The Commission should indicate a preference for updating the PCA deadband annually to account for changing economic relationships. When underlying economic conditions change (for example a change in the hydroelectric generation and electricity market price relationship) prior NVPC modeling and any associated findings or conclusions become invalid.*

Id. at Galbraith/2-3. Again, I am not recommending that the Commission adopt either a PCA or the HGA. Should the Commission choose to implement some mechanism, an "extreme event" PCA such as the one proposed by Staff is a more acceptable concept than a PCA that would be in effect most of the time. However, an "extreme event" hydro-only adjustment clause would be preferable to a comprehensive PCA (with an "all encompassing" scope of cost recovery) as envisioned by the Staff. A full PCA has not been justified based on the record in this Docket, would be a much more complex undertaking, requires much more regulatory activity, and would not necessarily achieve Staff's goal of revenue neutrality. Further, an extreme event HGA would be far more consistent with PGE's original request.

Staff Recommendation # 3

- *The Commission should adopt an interim PCA for calendar years 2005 and 2006. The deadband should be set at an amount equal to the revenue requirement effect of plus and minus 250 basis points of ROE.*

Id. at Galbraith/3. Although I agree a broad deadband is preferable to PGE's proposed $2.5 million deadband, I continue to disagree with Staff's recommendation for an interim PCA in 2005 and 2006.

<u>Staff Recommendation # 4</u>

- *The Commission should ensure any proposal does not incent direct-access eligible customers on their choice to go direct access or remain with the company.*

<u>Id.</u> I agree with this recommendation.

Q. STARTING WITH YOUR FIRST AREA OF DISAGREEMENT, EXPLAIN WHY YOU DO NOT BELIEVE THAT A PCA HAS BEEN JUSTIFIED BY THE RECORD IN THIS PROCEEDING.

A. The discussion in Mr. Galbraith's testimony seems to be based on the premise that some form of a comprehensive PCA should be the ultimate outcome of this proceeding. However, neither PGE, nor CUB, nor ICNU has presented testimony recommending a comprehensive PCA in this case. Thus, Staff is out of step with the rest of the participants in this docket.

Further, there has been no opportunity to fully formulate and explore the pertinent issues related to a PCA. This is a serious problem because a comprehensive PCA is a much more substantial change to the current regulatory practice for PGE than even the Company's proposed HGA.

Q. PLEASE EXPLAIN THE DIFFERENCES BETWEEN A COMPREHENSIVE PCA AND THE PROPOSED HGA.

A. A PCA is generally intended to track <u>all</u> changes in power costs, including those resulting from changes in fuel prices, plant outages, purchased power expenses, and hydro variations. Staff's proposed PCA would also track changes in gas sales revenue. Staff/100, Galbraith/14. The HGA was intended to only allow tracking of changes in power costs due to changes in hydro generation. Thus, the HGA was a proposal with a much more limited scope, and this docket was established to investigate <u>that</u> proposal, not to deal with the issue of a full PCA.

Staff's proposal presents a serious problem of equity in that parties are now obligated to address a much broader range of issues than were present at the start of the case. This also is a serious problem because Staff has not provided a specific PCA tariff to examine, projections of ratepayer impact, or rules or procedures to govern the annual process of reviewing and determining the ratemaking treatment of any PCA balance.

The Staff proposal also broadens the scope of power cost recovery to encompass a wide range of causes that have nothing to do with hydro generation. A serious plant outage, such as PacifiCorp's November 2000 outage of Hunter Unit 1, could result in an automatic pass-through of costs based on the Staff proposal. Another Western energy crisis might result in the same.

Q. ARE YOU SAYING THAT THE COMMISSION WOULD NOT WANT TO AFFORD PGE RELIEF IN SUCH EXTREME CIRCUMSTANCES AS A MAJOR PLANT OUTAGE OR POWER CRISIS?

A. Not at all. As I pointed out in my direct testimony, the Commission has a history of providing appropriate and measured relief in such situations. However, it is troubling when such recovery becomes a certainty, without the underlying opportunity for a prudence review or even the determination of a true financial need. Under Staff's proposal, PGE might be afforded automatic recovery of an imprudent plant outage. Likewise, a spike in power costs might be afforded automatic recovery even if the Company was overearning.

In the end, the greatest flaw in Staff's proposal is that it is premature. There are a number of issues that should be addressed before a PCA is adopted. Staff's proposal really truncates a fair and reasonable process because it assumes that a PCA is the "right solution," without providing the justification for a comprehensive PCA. Furthermore, Staff ignores many practical implementation issues that would accompany a PCA. Staff has lost sight of the issues in this case, and not really addressed the many issues that would accompany a case concerning a comprehensive PCA.

Q. WHAT STEPS ARE NECESSARY BEFORE A COMPREHENSIVE PCA IS IMPLEMENTED?

A. There should be a multi-step process. First, PGE or Staff should demonstrate to the Commission that a PCA is necessary and justified, and that a PCA represents the best means for dealing with power cost variances.[1/] This would logically take place in the context of a full general rate case. Second, there should be a rulemaking to define the scope of eligible costs, minimum filing requirements, and time schedules for processing PCA cases. Finally, there should be an investigation of provisions for prudence reviews and an audit or reconciliation procedure to assure that non-power cost items are not being included in the PCA balance.

Q. WHY IS A GENERAL RATE CASE NECESSARY BEFORE DECIDING WHETHER TO IMPLEMENT A PCA?

A. I discussed this in my direct testimony. ICNU/100, Falkenberg/10-12. In this case, PGE contends it is not earning an adequate return on equity ("ROE") and proposes the HGA to address that issue. A full rate case setting is the only reasonable forum to allow the Commission to determine the validity of PGE's claim and determine whether a remedy is justified.

[1/] While PGE brought this question up in UE 137 and UE 149, to this point, the parties have never agreed on a PCA concept. PGE itself withdrew its request for a PCA in UE 137.

Staff also seems to agree that a permanent PCA needs to be designed in the context of a full general rate case. However, it recommends that a two-year PCA be implemented now.[2/] Unfortunately, a temporary PCA presents the same problems and concerns to the Commission as would be present in the case of a permanent PCA. Consequently, Staff's position on this point seems inconsistent. Further, it makes little sense to proceed with a temporary PCA, if the intent is only to replace it with a final PCA later on.

Q. IS STAFF PROPOSING THE TEMPORARY PCA AS AN EMERGENCY MEASURE TO DEAL WITH THE CURRENT DROUGHT?

A. No. Staff provides very little justification for the temporary PCA in its testimony. The basic argument is one of developing a "fair allocation" of NVPC risk. Mr. Galbraith testifies as follows:

> *Staff recommends the interim PCA as part of a long-term commitment to the fair allocation of NVPC risk. Staff's interim PCA bridges the gap until a long-term PCA can be implemented. We believe it is important to maintain this long-term focus. Without further examination of the facts underlying Docket UM 1187, staff is unsure if the 2005 hydro variance warrants deferred accounting on a one-time stand-alone basis. However, we have already noted the similarity between our interim PCA and the Commission's use of 250 basis points of ROE to benchmark the financial impact of poor hydro in Order 04-108.*

Staff/100, Galbraith/27. Of course, it is not possible to make an objective determination of what is "fair." However, I question how "fair" the Staff proposal is to ratepayers since it allows the Company to establish a PCA and

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[2/] "*Staff recommends that PGE use Expected Value Power Cost modeling in its next general rate case. This modeling should be used to jointly determine the NVPC component of PGE's revenue requirement and the deadband parameters of an extreme event PCA mechanism.*" Staff/100, Galbraith/14.

collect costs for which the Company has never even previously requested a deferral. I will discuss this problem in more depth later.

Q. WHY WOULD A RULEMAKING BE NECESSARY BEFORE IMPLEMENTING A PCA?

A. There needs to be a reasonable definition of eligible power cost expense. While it may seem simple to define eligible expenses, it is not. Already in this case Staff proposes to include gas resale revenues as part of net power cost expense. In recent RVM cases, there have been a number of issues that have arisen surrounding the proper scope of costs for inclusion in the RVM. For example, PGE has requested recovery of costs related to foreign currency hedges. Likewise, recovery of costs related to "coal dust" and call options have been included in RVM filings, and opposed at various times by parties, <u>including</u> the Staff. In fact, there has been much discussion in the RVM cases as to which costs should be included and which should not.

The RVM is a fundamentally different exercise than a PCA, and the issues would most certainly differ. However, there is no reason to expect that there would be general agreement regarding the kinds of costs that should be eligible for recovery. While "coal dust" might not be an issue in a PCA case, an unexplained decline in coal inventories might give rise to a request for recovery.[3/]

Likewise, in the recent PacifiCorp power cost audit, out of period adjustments were a very contentious issue, even after Staff hired an outside auditor to review PacifiCorp's books. Thus, a rulemaking is needed to prevent a PCA from spawning either a series of unwieldy and open-ended dockets that

[3/] Such a decline might occur whenever coal pile measurements are updated.

wrestle with a variety of issues over and over again or the alternative, which would amount to no review of eligible costs and essentially a "blank check" for PGE.

Further, without minimum filing requirements and reasonable time schedules, parties may be severely handicapped in their ability to audit PGE's requests. Staff provides no guidance on how PCA cases are to be processed once the PCA is implemented.

Q. WOULD THE SAME PROBLEMS BE PRESENT IN A FORMULISTIC APPROACH SUCH AS PGE'S PROPOSED HGA?

A. No. PGE's request deals only with application of a simple formula. While I believe PGE's approach is flawed, opening up this Docket and future dockets to include consideration of actual power costs (based on accounting data) and use of an ROE threshold substantially broadens the scope of the proposed PCA and greatly complicates future regulatory proceedings. That Staff proposes no specific mechanism for dealing with these issues is quite troubling, for one is left with the concern that audits of future PCA balances may not be a high priority.

While I am not enthusiastic about PGE's HGA either, it is actually a far less troubling proposal than Staff's, aside from the HGA's narrow deadband. While it appears clear that PGE's HGA will allow over-recovery of the costs of hydro deficits and under-refunds when a surplus occurs, Staff's proposal may be as bad, if not worse, in that it will allow recovery of costs that have nothing to do with hydro variations. In addition, Staff's proposal does not match cost recovery or refunds with any measure of the financial position of the Company. Finally, there is no evidence that Staff's proposed PCA complies with Staff's recommended "revenue neutrality" standard.

Q. DO YOU AGREE WITH STAFF'S PROPOSAL TO ALLOW ITS PROPOSED PCA TO RETROACTIVELY APPLY TO 2005?

A. No. Mr. Galbraith testifies that the deferral application the Company filed in UM 1187 is sufficient to allow the Commission to apply Staff's proposed PCA retroactively to 2005:

> *PGE filed an application for deferral of costs and benefits due to hydro generation variance on December 30, 2004 (Docket UM 1187). PGE indicated in its initial application that it intended to capture the any hydro generation variance in 2005 for rate treatment pursuant to the outcome of UE 165. As we indicated in our Staff Report in this docket, presented at the July 6, 2004 Commission Public Meeting, the Department of Justice has indicated that the Commission has the discretion to authorize deferred accounting retroactive to the deferral application date, but it is not required to do so. The UM 1187 application provides the Commission options with respect to the date at which benefits and costs associated with PGE's proposed HGA mechanism are eligible for deferral. Staff believes the Commission also has the discretion to modify the balancing account formula to track positive or negative NVPC variance during 2005.*

Staff/100, Galbraith/27. I believe that Mr. Galbraith is recommending that the Commission engage in retroactive ratemaking, which is ill-advised from a regulatory policy standpoint.

It is my understanding that the Commission and parties will address PGE's deferred accounting application in UM 1187; however, if Staff's proposal is approved, it would certainly create a troubling precedent for regulators, ratepayers, and perhaps even utilities. In effect, Mr. Galbraith argues that an application for deferral of one type of cost is sufficient to allow deferral of a whole range of loosely-defined "related" costs. In UM 1187, the Company requested deferral of replacement power costs resulting from a shortfall in hydro generation. The Staff proposal would now retroactively allow the Company to defer <u>any</u> component of net power cost variations as well as gas resale revenues based on a deferred accounting application related only to hydro generation variances. If the Commission adopts the Staff proposal, it will "let the genie of retroactive ratemaking out of the bottle of deferred accounting" and greatly complicate the regulatory treatment of deferred costs in future cases.

Q. EXPLAIN THE REGULATORY SIGNIFICANCE OF DEFERRED COSTS.

A. As a general principle, there is a strict prohibition against retroactive ratemaking. <u>See</u> Or. Att'y Gen. Op. No. 6076 (Mar. 18, 1987). The reason is that regulators do not want to have to deal with the problem of constant rate adjustments that would naturally occur because a utility will never exactly earn its allowed rate of return. Once a rate case is decided, regulators, customers, and utilities need finality. If a utility had an unexpected cost (or obtained some sort of windfall), one party or the other might seek an after the fact adjustment to eliminate the effects on earnings. This would quickly result in a chaotic situation, making rate setting much more difficult and complicated. Thus, regulators will generally not allow utilities to charge for costs that were incurred between rate cases and outside of any particular test year. To circumvent problems that might accompany unusual circumstances, regulators will sometimes grant an application to defer <u>certain specific costs</u> occurring outside of a test year so that a utility may request later recovery without fear of foreclosure on the grounds of retroactive ratemaking.

The problem with the Staff proposal is that it would allow a retroactive modification to the scope of costs being deferred. This could create countless problems in future deferral cases, for both utilities and customers.

Q. PLEASE PROVIDE SOME EXAMPLES OF THESE POTENTIAL PROBLEMS.

A. There are many possible scenarios that might arise.

One example might be a request for deferral of a specific new tax. For example, a utility might request deferral of a new environmental tax. If the Commission accepts the Staff proposal, it seems logical that a party might propose to expand the original deferral request to allow recovery (or refund) of any type of tax. There is no reason a "net taxation" deferral would be any different from Staff's proposed net power cost deferral. A utility facing a new tax, but suffering from an earnings drop, might be faced with a negative deferral balance because income taxes dropped far more than the amount of the new taxes. Alternatively, a utility might file for a single tax item change, but later try to include other new taxes, after the fact. Indeed, deferral cases would lose all meaning as any type of similar cost might be argued as fair game for deferral.

Another example occurred in the Settlement in UE 149, in which PGE requested deferral of unknown coal contract costs. Under the Staff proposal in this case, it would appear that the Company might be allowed retroactively to defer any kind of fuel cost change, not just coal, and indeed, might defer any type of power cost change. While this may seem farfetched, it follows from the same principle as the Staff proposal, where a deferral for increased costs due to changes in hydro generation becomes a deferral of all net power cost variations and gas resale revenues to boot.[4/]

Another item utilities commonly defer is costs related to storm damage to the distribution system. Under Staff's recommendation, it would now be entirely possible that a deferral for storm damage costs might expand to include any kind of distribution cost. Ultimately, the problem with the Staff proposal is that it would make a deferral request into a blank check, limited only by the creativity of the utilities' accountants and the various rate case witnesses. This would eventually undermine the entire concept of deferred accounting and could well lead to its elimination due to abuse.

Q. DO YOU HAVE ANY CONCERNS REGARDING STAFF'S 250 BASIS POINT DEADBAND PROPOSAL?

A. Yes. I have three concerns. First, the Staff estimates this to be $40 million per year, but does not provide any specific figures to support this assumption. Indeed, reliance on a 250 basis point deadband is complicated because it requires financial data to calculate. This could either entail use of un-audited financial results, projected financial results, or data from the most recent rate case. Staff has not explained specifically how it would determine the deadband.

Second, and more significantly, Staff has indicated that a symmetrical deadband for the HGA could lead to a windfall for PGE, but it still proposes one for the interim 2005 and 2006 PCA. Staff/100, Galbraith/2-3. I believe that all

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[4/] Heretofore, gas resale revenues have been considered part of other revenues, not net power costs, according to Mr. Galbraith. Staff/100, Galbraith/17. Under the Staff proposal, this item would be eligible for retroactive deferral.

parties to the case now agree or acknowledge that there is an asymmetrical hydro cost risk. Nevertheless, Staff proposes a symmetrical deadband.

Finally, there is the practical issue of timing accompanying the Staff deadband. It would be necessary to decide whether the deadband applies monthly, quarterly, or annually. This has not been addressed by Staff. A monthly deadband might allow the Company to make a positive deferral, because certain months had cost variations in excess of 250 basis points (annualized), even though the annual variations did not exceed that deadband. Again, issues of this sort need to be addressed in a rulemaking.

Q. WOULD THE STAFF PCA COMPLICATE AND INTENSIFY REGULATION?

A. Yes, particularly if a more narrowly defined deadband were adopted. The presence of a PCA could (or at least should) greatly complicate and intensify regulatory efforts. Given the current status of the RVM cases, there are many instances in which such issues will arise.

For example, in UE 139, the Commission disallowed $14.5 million in costs related to four above-market contracts from the 2003 RVM power cost estimate. In the settlements in UE 149 and UE 161, similar reductions in NVPC were made related to these contracts. Staff's PCA testimony includes no discussion regarding deductions for costs disallowed by the Commission in the RVM. As a result, unless these contract costs were also eliminated from the PCA actual cost filing, customers could still end up pay for costs already disallowed by the Commission. Staff has failed to fully explain how it would address the RVM process in the development of the "actual costs" used in the PCA filing.

Q. WOULD PARTIES HAVE THE OPPORTUNITY TO IDENTIFY SUCH PROBLEMS IN THE PGE PCA FILING?

A. Perhaps, but Staff has not explained any of the details of this process. Unless parties have several months for review and discovery, it would be difficult to do anything more than a cursory review of the filing, with limited opportunity to challenge the necessity, reasonableness, and eligibility of costs.

Q. WHAT IS THE EXPERIENCE IN OTHER STATES WHEN PCA PROCEDURES ARE IN PLACE?

A. There are many issues that arise concerning the proper accounting of costs for ratemaking purposes when a PCA is used. In some instances, fraud or criminal activity is discovered in addition to many more mundane accounting issues. I have participated in cases where both kinds of issues have arisen. Exhibit ICNU/201 summarizes some of the issues that have arisen in proceedings in which I have participated or of which I am aware. Some of these issues may be applicable to PGE and others may not. However, this list demonstrates the broad scope of issues that can result from implementing a PCA.

Q. AREN'T THE ISSUES THAT THE COMMISSION REVIEWS IN APPROVING COSTS IN A PCA THE SAME KIND AS MIGHT ARISE IN ORDINARY RATE CASES?

A. Yes. Certainly, it is safe to assume that the OPUC carefully reviews all pertinent information in a rate increase request. I would be quite surprised if the Commission simply adopted an attitude of automatic acceptance of the utility's requested costs. This same attitude and approach must also be applied in relation to costs recovered via a PCA whenever the actual power costs fall outside of the deadband.

In a number of the cases listed in Exhibit ICNU/201, the issues that were contested were created by the presence of a PCA approach. In one case (SPS), the utility company created a corporate fuel-purchasing and handling subsidiary (and later sold it). This allowed many base rate items to become part of eligible fuel cost expense. In other cases, there was substantial debate about whether the costs in question were eligible for pass-through accounting, even though they may have been legitimate ratemaking expenses. This is important, because a PCA should not be viewed as a means of obtaining "on the spot" rate treatment for any base rate item that can be disguised as fuel or power cost-related. Indeed, this is already a problem with the RVM process. The Commission should not intensify this problem by granting PGE a PCA.

In addition, regulatory lag between rate cases creates pressure on management to minimize costs. This provides incentives to minimize outages and use the least cost energy supply strategy. With a PCA, there is need to audit all types of plant outages, plant efficiencies, power sales and purchases, and a variety of other issues depending on the specifics of the mechanism. A PCA will greatly complicate and intensify regulatory efforts, unless the Commission is prepared to automatically allow recovery of the very kinds of costs it would examine carefully in a rate case.

Rate cases are intended to provide sufficient time to examine costs. Prudence, reasonableness, and accounting issues can be fully explored. Unless there is a PCA review process that allows for sufficient time to analyze actual costs, there is great danger that ratepayers will pay for costs that are not legitimate ratemaking expenses.

Q. IF STAFF'S PROPOSED DEADBAND IS ADOPTED, DOES THIS MINIMIZE THE LIKELIHOOD THAT ADDITIONAL AUDITS WOULD BE NEEDED?

A. Certainly a broad deadband would imply that there would be fewer times when the Company might obtain rate treatment for additional power costs. However, I believe that some form of audit needs to be undertaken every year to establish whether the actual power costs fall within the deadband or not. If the Commission makes a decision regarding whether NVPC fell within the deadband, it is implicitly accepting the components of NVPC as filed by the Company. Utilities are quite adept at claiming precedents in cases where costs have been "approved" in rates cases, or at least not disallowed, when no challenge was raised. It is not hard to imagine a set of circumstances where the lack of a challenge to costs, revenues, or an accounting method included in PGE's calculation of NVPC for a given year (when the deadband was not exceeded) gives rise to a claim that a precedent had therefore been established. Thus, a comprehensive audit may be needed on an ongoing basis.

Further, if PGE is in a situation where NVPC is below the level included in rates, it would naturally have an incentive to overstate its costs, to avoid a refund. In such cases, an audit would be needed to verify the Company's claimed NVPC. All things considered, the Staff PCA will substantially complicate and intensify regulatory activity in Oregon, and I recommend that the Commission reject this proposal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT ICNU/201
ISSUES ARISING IN FUEL AND PURCHASE POWER REVIEW CASES

Southwestern Public Service ("SPS"), Public Utility Commission of Texas ("PUCT") Docket No. 19512. Employee lawsuit settlements charged to eligible fuel expense, allegations of fraud and billing errors in subcontractor invoices. Resulted in refund of various charges.

Big Rivers Electric Cooperative, Kentucky Public Service Commission Docket No. 92-490, 92-490A and 90-360. Bid rigging fraud and allegations of criminal behavior. Resulted in arrest and trial of the general manager.

Utah Power Company, Utah Public Service Commission Case No. 84-035-12. Allegations stemming from a "whistle-blower" resulted in a refund to ratepayers.

Houston Lighting and Power Company ("HL&P"), PUCT Docket Nos. 18753 and 26195. Eligibility of mine closing costs. Removal of costs related to provision of spinning reserves to another utility, Central Power and Light Company ("CP&L"), as part of a nuclear plant construction lawsuit settlement.

Central Power and Light Company, PUCT Docket No. 27035. Allocation of trading profits and costs between affiliated companies.

Entergy Gulf States, Inc. ("EGSI"), PUCT Docket Nos. 21111 and 23550. Prudence and cost of extended thermal plant outages, eligibility of affiliate purchases.

Georgia Power Company, Georgia Public Service Commission Docket No. 3741-U. Acquisition planning for a low-sulfur coal plant.[5/] Rate treatment of payment of "front-end costs" for development of failed coal mine.

[5/] This issue was also litigated in the Big Rivers cases mentioned above.

ICNU/103

Comparison of Projected 2005 Hydro Deficit to Historical Averages

Exhibit ICNU/103
Comparison of Projected 2005 Hydro Deficit to Historical Averages

	Year	Hydro Production (MWa)	% of Average	mWh Deficit	Deficit GT Projected 2005 Deficit =	-568 Avg. mW
1	1929	466.6	82.5%	-868.0	1	
2	1930	456.3	80.7%	-958.2	1	
3	1931	457.0	80.8%	-952.1	1	
4	1932	557.1	98.5%	-75.2	0	
5	1933	611.3	108.1%	399.6	0	
6	1934	569.9	100.7%	36.9	0	
7	1935	524.8	92.8%	-358.2	0	
8	1936	494.4	87.4%	-624.5	1	
9	1937	496.5	87.8%	-606.1	1	
10	1938	554.3	98.0%	-99.8	0	
11	1939	484.4	85.6%	-712.1	1	
12	1940	488.6	86.4%	-675.3	1	
13	1941	495.1	87.5%	-618.4	1	
14	1942	518.7	91.7%	-411.6	0	
15	1943	575.0	101.6%	81.6	0	
16	1944	449.2	79.4%	-1020.4	1	
17	1945	497.9	88.0%	-593.8	1	
18	1946	588.4	104.0%	199.0	0	
19	1947	586.4	103.7%	181.4	0	
20	1948	614.4	108.6%	426.7	0	
21	1949	555.6	98.2%	-88.4	0	
22	1950	664.3	117.4%	863.8	0	
23	1951	651.6	115.2%	752.6	0	
24	1952	565.8	100.0%	1.0	0	
25	1953	594.8	105.1%	255.0	0	
26	1954	649.8	114.9%	736.8	0	
27	1955	603.9	106.8%	334.7	0	
28	1956	643.5	113.8%	681.6	0	
29	1957	560.6	99.1%	-44.6	0	
30	1958	586.9	103.7%	185.8	0	
31	1959	643.8	113.8%	684.3	0	
32	1960	581.5	102.8%	138.5	0	
33	1961	595.8	105.3%	263.8	0	
34	1962	576.6	101.9%	95.6	0	
35	1963	547.8	96.8%	-156.7	0	
36	1964	589.0	104.1%	204.2	0	
37	1965	585.0	103.4%	169.2	0	
38	1966	552.2	97.6%	-118.2	0	
39	1967	574.4	101.5%	76.3	0	
40	1968	590.0	104.3%	213.0	0	
41	1969	588.6	104.1%	200.7	0	
42	1970	531.4	93.9%	-300.4	0	
43	1971	639.7	113.1%	648.3	0	
44	1972	672.3	118.8%	933.9	0	
45	1973	517.5	91.5%	-422.1	0	

46	1974	665.1	117.6%	870.8	0	
47	1975	618.8	109.4%	465.3	0	
48	1976	627.7	111.0%	543.2	0	
49	1977	493.4	87.2%	-633.2	1	
50	1978	559.5	98.9%	-54.2	0	
51	1979	508.3	89.9%	-502.7	0	
52	1980	542.9	96.0%	-199.6	0	
53	1981	581.2	102.7%	135.9	0	
54	1982	637.1	112.6%	625.6	0	
55	1983	634.4	112.1%	601.9	0	
56	1984	619.0	109.4%	467.0	0	
57	1985	526.5	93.1%	-343.3	0	
58	1986	576.4	101.9%	93.8	0	
59	1987	499.0	88.2%	-584.2	1	
60	1988	503.3	89.0%	-546.5	0	
		565.7		Number	12	
					20.0%	
				One in	5.00	Years

ICNU/104

PacifiCorp's Responses to
ICNU Data Request Nos. 8.3, 8.4, 8.11,
8.12, 8.13, and 8.14

May 3, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165 /UM-1187
PGE Response to ICNU Data Request 8.3
Dated April 21, 2005
Question 038

Request:

Please provide a copy of the final 2005 RVM Monet model with all input data that will be modified in computation of the deferral highlighted in color.

Response:

PGE objects to this request on the basis that it is unduly burdensome. PGE provided ICNU a copy of the final 2005 RVM Monet model and ICNU can do this work based on the terms of the stipulation.

May 3, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165/UM-1187
PGE Response to ICNU Data Request 8.4
Dated April 21, 2005
Question 039

Request:

Please provide a list of all calculations in Monet that will be changed in order to compute the deferral under the Stipulation.

Response:

PGE objects to this request on the basis that it is unduly burdensome. PGE has not completed the modifications necessary to implement the stipulation. When PGE finishes its modifications, we will provide a copy of the Monet model to all parties.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.11
Dated April 21, 2005
Question 046

Request:

Reference Staff-PGE/100, Galbraith-Tinker/3: "In addition to the actual hourly generation figures, PGE will also update the monthly actual hydro generation for these plants. These monthly actual generation figures will then flow through the model to affect three other power cost components -- the Wells Settlement Agreement, PGE's Mid-C indexed purchase from the Confederated Tribes of the Warm Springs, and the Priest Rapids Renewal Contract Reasonable Portion Auction Payment."

Please provide a sample calculation showing how these computations will be performed for each month from January 2005 to present. Please note that, like all ICNU data requests, this is a continuing request that should be updated as new data becomes available. To the extent that insufficient actual data is available to perform this calculation, please provide a sample calculation using hypothetical or estimated data.

Response:

PGE objects to this request on the basis that the ongoing nature is unduly burdensome. Without waiving its objection, PGE replies as follows:

PGE has not yet completed the Monet enhancements that will affect the Wells Settlement Agreement, PGE's Mid-C indexed purchase from the Confederated Tribes of the Warm Springs, and the Priest Rapids Renewal Contract Reasonable Portion Auction Payment. See Attachment 036-A for a comparison of our current modeling and the provisions of the stipulation for these items.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.12
Dated April 21, 2005
Question 047

Request:

Reference Staff-PGE/100, Galbraith-Tinker/3: "PGE will also make an adjustment to reflect Daylight Savings Time, something Monet does not model directly."

Please explain specifically how this adjustment will be made.

Response:

As noted in Attachment 036-A to PGE's response to ICNU Request No. 036, PGE has not yet modified the Monet model to reflect Daylight Savings Time.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.13
Dated April 21, 2005
Question 048

Request:

Reference Staff-PGE/100, Galbraith-Tinker/3: "PGE will start with actual day-ahead on and off-peak prices from the Dow Jones Mid-Columbia Daily Electricity Price Index and the actual shape of hourly prices from the Dow Jones Mid-Columbia Hourly Electricity Price Index. PGE will apply the hourly index shape to the daily forward on and off-peak index prices to obtain hourly prices that are consistent with the daily on and off-peak prices, but which follow the observed hourly shape. We will fill any gaps in the hourly data with available data from similar periods."

Please provide a sample calculation showing how these computations will be performed for each month from January 2005 to present. Please note that, like all ICNU data requests, this is a continuing request that should be updated as new data becomes available. To the extent that insufficient actual data is available to perform this calculation, please provide a sample calculation using hypothetical or estimated data.

Response:

PGE objects to this request on the basis that the ongoing nature is unduly burdensome. Without waiving its objection, PGE replies as follows:

As noted in PGE's response to ICNU Request No. 036, PGE has not yet completed all of the Monet enhancements necessary to implement the stipulation. Attachment 036-A compares our "Current Model" with what will be necessary to implement the stipulation. PGE's response to ICNU Request No. 036 also includes Attachment 036-C, which contains hourly Mid-C electric prices for the first three months of 2005. PGE developed these hourly prices according to the methodology described in the response to ICNU Request No. 036.

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.14
Dated April 21, 2005
Question 049

Request:

Reference Staff-PGE/100, Galbraith-Tinker/4: "First, PGE will enhance Monet so that it can accept daily gas prices, as it currently runs based on monthly gas prices."

Please explain specifically how this logic change will be implemented, within Monet. Identify worksheets and subroutines that will change, and how the input data will be changed.

Response:

PGE has not yet completed the enhancements that will allow Monet to accept daily gas prices. Attachment 036-B provides actual daily gas prices for the first three months of 2005.

ICNU/105

PacifiCorp's Response to ICNU Data Request No. 8.2

May 12, 2005

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 8.2
Dated April 21, 2005
Question 037

Request:

Please provide a calculation using either the RVM 2005 Final Monet model or hourly diagnostic reports from that run illustrating how the deferral calculation will be performed in the modified Monet model based on actual data starting January 2005 to present. Please note that, like all ICNU data requests, this is a continuing request that should be updated as new data becomes available.

Response:

PGE objects to this request on the basis that the ongoing nature is unduly burdensome. Without waiving its objection, PGE replies as follows:

Attachment 037-A is an Excel file on CD, "MonetJan-Mar2005," which provides the PC-Input sheet and the summary output files from a Monet run for the first three months of 2005. As discussed in PGE's response to ICNU Request No. 036, PGE has not yet completed all enhancements in the Monet model necessary to implement or model the stipulation. The Monet run that is the source of Attachment 037-A is consistent with the "Current Model" described in Attachment 036-A. Attachment 037-A is confidential and subject to the Modified Protective Order in this docket (OPUC Order No. 04-406).

The deferral calculation is not performed in the Monet model. Rather, as discussed in the stipulation, the variance is calculated by comparing the base and updated Monet runs. ICNU can compare the power cost output information in Attachment 037-A with the power cost output information in PGE's final 2005 RVM Monet model run. PGE has not performed this calculation except for the first three months of 2005 as in the table below:

Monet Run	Jan-Mar 2005 Power Costs
Base 2005 RVM	$124,112,000
Attachment 037-A	$135,228,000
Variance	$ 11,116,000

We do not know what will happen during the remainder of 2005. However, if the annual variance were $11.116 million, i.e. annual net variable power costs $11.116 million more than forecasted in the RVM Monet run, then the mechanism would indicate "no deferral," as $11.116 million falls within the dead band. The variance figure in the above table comes from a three-month period. Annualized, it would be $44.464 million. In the case of a $44.464 million annual variance, the mechanism would indicate a deferral (subject to an earnings test) of $23.571 million. The first $15 million would fall in the deadband; the sharing parameter would then allocate 80 percent of the remaining $29.464 million, or $23.571 million, to customers.

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