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June 4, 2010

Via Electronic and US Mail

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC
Request for a General Rate Revision.
Docket No. UE 215

Dear Filing Center:

Enclosed please find the original and five (5) copies of the following testimony on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket:

- Opening Testimony of Randall J. Falkenberg (ICNU/100) with Exhibits (ICNU/101, ICNU/102, ICNU/103, ICNU/105). Also enclosed are five (5) redacted copies of Opening Testimony. Confidential Exhibits ICNU/104 and ICNU/106, along with confidential testimony are being submitted in separate envelopes; and

- Opening Testimony of Dr. Alan Rosenberg (ICNU/200) with Exhibits (ICNU/201 – ICNU/207).

Also enclosed please find the original and five (5) copies of the following testimony on behalf of the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon in the above-referenced docket:

- Opening Testimony of Ellen Blumenthal (ICNU-CUB/100) with Exhibits (ICNU-CUB/101 – ICNU-CUB/105). Also enclosed are five (5) redacted copies of Opening Testimony. Confidential testimony is being submitted in a separate envelope; and

- Opening Testimony of Michael Gorman (ICNU-CUB/200) with Exhibits (ICNU-CUB/201 – ICNU-CUB/223)

Thank you for your assistance.

Sincerely,

/s/ Kelli R. Madden
Kelli R. Madden
Paralegal

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Opening Testimony on behalf of the of the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon upon the parties, on the official service list shown below for UE 215, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail where paper service has been waived.

Dated at Portland, Oregon, this 4th day of June, 2010.

Sincerely,

/s/ Kelli R. Madden
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

SUBJECT TO GENERAL PROTECTIVE ORDER

(Confidential Information Removed)

June 4, 2010

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Sandy Springs, Georgia 30350.

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

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

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

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

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

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. In this phase of the proceeding, I address PGE's request to modify its Power Cost Adjustment Mechanism ("PCAM"). My conclusions and recommendations are as follows:

1. I recommend the Commission deny PGE's request to modify the PCAM. The current PCAM has allowed PGE to over-recover power costs for the past two years. The first two PCAM cases demonstrate that the current structure does not prevent PGE from recovering prudently incurred costs.

2. PGE's arguments, particularly those made by Mr. Fetter, were already considered and addressed by the Commission in Docket UE 180. Mr. Fetter fails to address the Commission's reasoning in adopting the current PCAM structure.

3. Mr. Fetter doesn't consider the facts and circumstances surrounding PGE's current PCAM. His entire argument in support of changing the PCAM is premised on a misunderstanding of the ultimate goal of regulation. The goals of regulation are multifaceted and are not simply to assure exact, dollar for dollar recovery of any particular cost.

4. Mr. Fetter also has a rather naïve view of the efficiency of regulation in identifying and disallowing imprudent costs. In reality, he is proposing a rather lax, laissez-faire regulatory process.

5. Mr. Fetter's focus on statements from various banks and bond rating firms is misleading and unpersuasive. These firms have a tarnished image and have in the past allowed PGE to edit their reports for self serving purposes. PGE continues to have a very close relationship with the firms it pays to rate its bonds. The OPUC should give little weight to the statements made by these entities.

6. Mr. Fetter makes a rather paradoxical argument that changing the PCAM would reduce PGE's cost of borrowing, but have no impact on the Company's cost of equity. If true, then there is little potential benefit in modifying the PCAM.

7. Mr. Fetter testifies that the use of prudence disallowances by itself is sufficient to spur appropriate utility behaviors. He provides no evidence in support of this assumption, and the facts suggest otherwise.

<u>PGE's Request to Change the PCAM</u>

Q. PLEASE DESCRIBE PGE'S PROPOSED CHANGES TO THE PCAM.

A. The Company proposes to change the deadband from its current values (plus $39.9 million, and minus $19.95 million) to plus or minus $10 million. The Company also proposes to eliminate the earnings deadband built into the current PCAM. Table 1 below (taken directly from PGE/200, Pope/23) shows PGE's proposal. The support for these changes rests mainly on the testimony (Exhibit PGE/1300) of PGE witness Mr. Steven Fetter of the firm Regulation UnFettered. Mr. Fetter contends that the current PCAM structure would prevent the Company from collecting its prudently incurred NPC.

Feature	Proposed	Current
Deadband – Higher NVPC	$10 million	150 bp of authorized ROE. For 2011, this would equate to $39.9 million.
Deadband – Lower NVPC	$10 million	75 bp of authorized ROE. For 2011, this would equate to $(19.95) million.
Earnings Test - Refunds	Refunds will be made such that PGE's actual regulated ROE is no less than the Commission authorized ROE.	Refunds will be made such that PGE's actual regulated ROE is no less than 100 bp above the Commission authorized ROE.
Earnings Test – Collections	Collections will be allowed such that PGE's actual regulated ROE is no higher than the Commission authorized ROE	Collections will be allowed such that PGE's actual regulated ROE is no higher than 100 bp below the Commission authorized ROE.

Q. HAS PGE FULLY RECOVERED ITS NET POWER COSTS IN THE FIRST TWO PCAM CASES?

A. Yes. In the first two applications of the PCAM, PGE retained some of the actual NPC because of the earnings test and sharing mechanism. On the basis of this experience, there is no evidence to support any contention that PGE has been severely disadvantaged by the PCAM.[1/] Further, the first two PCAM cases, UE 201 and UE 211, resulted in settlements. Consequently, it appears that PGE found the current PCAM to be a structure that was well-defined, and the process lacking in controversy. Further, the last two AUT cases were settled as well, demonstrating all parties agreed on the baseline NPC as well.

1/ Of course, only a few observations does not make a significant sample. However, if the PCAM were perfectly "fair" meaning there was a 50-50 chance of over or under recovery, the odds are 1 in 4 that the Company would over collect for the first two years. If the PCAM were biased against the Company, as suggested by Mr. Fetter, one would have to assume the odds to be much lower.

<u>Fetter Testimony</u>

Q. HOW DOES MR. FETTER SUPPORT THE REQUEST TO CHANGE THE CURRENT PCAM?

A. Mr. Fetter states that the current PCAM fails to promote what he considers to be *the* ultimate goal of utility regulation:

> I do not believe that the current framework of that PCAM achieves what I believe should be *the* goal of utility regulation: timely recovery of all costs prudently expended by a regulated utility in order to provide reliable service to customers at a reasonable cost.

<u>Re PGE</u>, Docket No. UE 215, PGE/1300, Fetter/4 (emphasis added).

Mr. Fetter starts from a very wrong premise. He views *the* goal of regulation as ensuring timely recovery of all prudently incurred costs. This is clear because he stated it was "the goal" not "a goal." Mr. Fetter's views run contrary to accepted concepts of the role of regulation. Or. Rev. Stat. § 756.040 (2009); Leonard S. Goodman, <u>The Process of Ratemaking</u> 31-32 (Public Utilities Reports, Inc. 1998). Mr. Fetter's goal of full cost recovery might arguably be achievable without any regulation at all and perhaps with greater efficiency, albeit at the expense of equity. There are, in fact, outside of (and even within) the United States many utilities that set their own rates without any of the conventional regulatory oversight we are accustomed to in Oregon. Examples would include national or state-owned utilities, many cooperatives and municipal utilities, as well as federal agencies. However, for investor-owned utilities, some form of regulation is the norm, and PGE is no different from most in this regard.

Q. WHAT IS THE PURPOSE OF REGULATION?

A. The price and terms of service of monopolies are regulated to protect consumers from the potential abuse of monopoly power – no more – no less. We don't trust that private ownership of a monopoly will result in fair, just and reasonable rates or adequate service quality. Indeed, regulation is often described as a surrogate for competition in that it forces efficient service at fair prices. Leonard S. Goodman, The Process of Ratemaking at 135. Mr. Fetter seems to agree with this concept.[2/]

Q. DO COMPETITIVE MARKETS ASSURE COST RECOVERY FOR PARTICIPATING FIRMS?

A. No. In a competitive market, there is no assurance of recovery of any particular cost, nor any assurance that full cost recovery will ever occur for any particular firm. Indeed, there are examples of industries where full cost recovery has not occurred for long periods of time, such as the airlines. Further, there is little or no attention paid to the concept of prudence, as either a yardstick for setting prices, or as a measure of management efficiency. Prudence deals with *intents* and *expectations,* while competitive enterprises are concerned with *results*. Indeed, one of the greatest marketing failures of all time, the introduction of the "New Coke" was arguably a prudent decision.[3/] That fact did not result in the Coca Cola Company making a profit on the product.

To the extent it acts as a surrogate for competition, the purpose of regulation is not to provide greater advantages to the regulated entity than it would have in a competitive environment; nor is the goal to provide exact cost recovery of all prudent costs as Mr. Fetter seems to believe. Instead, the most commonly stated goal of regulation is to establish fair, just and reasonable rates. This may or may not entail exact cost recovery of any specific cost. Generally speaking, we normalize costs to smooth out

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2/ "The concept of utility regulation is to provide a surrogate for the competitive market that is not present when a company possesses monopoly or near-monopoly status with regard to an essential good, such as utility service." Testimony Before the Members of the Joint Committee, Indiana Legislature, September 12, 2007, page 12 (Source: Data Response ICNU-CUB 57-A); see also, Re PGE, Docket No. UE 215, PGE/1300, Fetter/24.

3/ New Coke was carefully researched with taste testing, prior to introduction, and well-received in the process. Coca Cola executives, however, failed to anticipate the negative reactions of the longstanding customer base.

year by year variations due to weather, outages and the like. This fact, by itself implies there will never be exact cost recovery of utility costs.

I do agree that for a utility to provide reasonable service reliability, over the long run, it should have the *opportunity* to earn a rate of return sufficient to attract capital on reasonable terms. This does not imply that there will be an assurance that the utility will exactly recover no more or less than a sufficient return every single year, or that it will perfectly recover any particular cost. Indeed, as discussed above, PGE recovered more than its actual power costs for the past two years, and also earned at or above its authorized ROE in 2007[4/] and 2008.[5/] On this basis, it is fair to ask where is the injustice in the current structure that Mr. Fetter is so concerned with?

Q. IS THERE A REASON WHY THE IDEAL OF EXACT COST RECOVERY AS SUGGESTED BY MR. FETTER IS NOT AVAILABLE UNDER CURRENT OREGON PRACTICE?

A. Yes. Oregon allows utilities to use a fully projected test year to set rates. This eliminates regulatory lag which would accompany the use of a purely historical test year. Under an historical test year, exact cost recovery might be possible, but at the cost of a lag between cost incurrence and cost recovery. In exchange for eliminating regulatory lag, projected test years are used, but we then are faced with a new problem – forecast error. At least in Oregon, it appears that utilities would prefer the latter, to the former. The problem with Mr. Fetter's testimony is that he is out of step with PGE's approach to rate recovery in Oregon. Taken to its logical conclusion, Mr. Fetter would seemingly advocate reliance on a purely historical test year. However, even that might fail to achieve his standard of timely cost recovery. In this sense, Mr. Fetter's testimony is self contradictory, as exact

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4/ Re PGE, UE 201, PGE/100, Tooman-Tinker/11.
5/ Re PGE, UE 211, PGE/100, Tooman-Tinker/2.

cost recovery is arguably not consistent with timely recovery. Further, even if one were to solve that problem, there is always the problem of forecast error in billing units – forecasted sales will never equal actual sales. In the end, the only way to rationalize Mr. Fetter's testimony is that he seeks the best of both worlds – forecasted costs would be used when that works best for the utility, and if not, then historical costs would be used. This is hardly a balanced approach.

Q. COMMENT ON MR. FETTER'S ELEVATION OF THE PRUDENCE STANDARD OVER OTHER TRADITIONAL CONSIDERATIONS SUCH AS EQUITY AND COST MINIMIZATION.

A. Based on Mr. Fetter's testimony quoted above, he has little room for any standard other than prudence. He certainly doesn't mention any other standard. A good example concerns affiliate transactions. It might be prudent for PGE to engage in affiliate transactions which help its bottom line. However, that might result in ratepayers being charged affiliate costs. Equity, reasonableness and efficiency are also important standards.

Fortunately, prudence is not the only standard for cost recovery. Under a pure "prudence" standard, for example, it might be argued that there is no need to *minimize* costs. Prudence is actually a very low qualifying standard, and it certainly is not the only goal of a well run utility. Efficiency and cost minimization should also be goals, and are arguably higher standards than mere prudence. Viewed in isolation, prudence does not necessarily require efficiency improvements to be sought out or implemented.

For example, a utility may not be obligated to seek out ways to improve plant reliability, or improve heat rates under the prudence standard. It does so, as a *proactive* step to minimize costs. However, it would arguably be reasonable to simply not look for cost saving measures. Likewise, a utility may not need more than a few competitive bids from suppliers to obtain a "prudent" price, though a larger number of bids may result in a lower price. And, no matter how prudence is defined or measured, regulators would have a very difficult time determining whether the utility missed opportunities to save costs. To do so would require an enormous amount of regulatory oversight, and require the regulators to have access to all the information readily available to utility managers. In effect, regulators would need to be "shadow-managers" of the utility. This is hardly practical, or desirable.

Q. DOES MR. FETTER'S VIEW OF PRUDENCE AND REGULATORY PRACTICE SEEM REALISTIC?

A. No. Mr. Fetter testifies as follows:

> [U]nder the Michigan PCAM the companies knew they had an obligation to carry out their fuel procurement and purchased power activities prudently – and when they didn't, they knew they would be subject to a financial disallowance.

Re PGE, Docket No. UE 215, PGE/1300, Fetter/15.

This strikes me as a very unrealistic, if not naïve view of how utilities operate in the face of regulation. Mr. Fetter is seemingly suggesting that the mere threat of a prudence disallowance was sufficient to ensure utilities operated in a prudent fashion. However, Mr. Fetter has acknowledged that there is a downside in the use of pass-through mechanism, as he testified in Missouri Public Service Commission Case No. ER-2007-0004, involving Aquila Networks:

> Q. IS THERE A DOWNSIDE TO USE OF A FAC?[6/]
>
> A. I alluded to it earlier. The expedited (and even sometimes near-automatic) operation of an FAC should not allow imprudent actions by a regulated utility to avoid regulatory scrutiny. If costs for fuel and power supply are not prudently incurred, there should

[6/] In this case, Mr. Fetter is discussing a Fuel Adjustment Clause, which is a close analog to a PCAM.

> be a process to allow challenge of such improper actions, followed by the ability of the regulatory body to order disallowances and prevent inappropriate recovery. Only in this way can a fair balance be struck between customer and shareholder interests.

Re Aquila Networks, Case No. ER-2007-0004, Missouri Public Service Commission, Rebuttal Testimony of Steven Fetter, page 21.

In effect, Mr. Fetter is agreeing that the shortened period for review and the near-automatic operation of a PCAM mechanism has the downside of allowing utilities the chance to recover imprudent costs because they may be concealed or go undetected in the regulatory process. Despite the view stated above, Mr. Fetter's response to ICNU-CUB Data Request No. 36 discounted the notion that regulators could fail to detect or disallow imprudently incurred costs.[7/] Mr. Fetter's position on this issue is puzzling to say the least.

Q. IN THE PASSAGE QUOTED ABOVE, MR. FETTER ALLUDES TO THE NEED FOR PROPER MONITORING OF PASS-THROUGH COSTS. HAS HE EXAMINED REGULATORY PRACTICE IN OREGON TO DETERMINE IF PROPER PCAM MONITORING EXISTS?

A. No. Mr. Fetter stated in his response to ICNU-CUB Data Request No. 56 that he had not determined whether the OPUC Staff conducted audits of the PGE PCAM in accordance with the standards listed in the NARUC Rate Case and Audit Manual.[8/] He also admitted in response to ICNU-CUB Data Requests Nos. 33, 34 and 35 that he had not even reviewed any of the previous PCAM filings.[9/] Nor has he examined the relationship between PGE's actual earnings and NPC recovery in prior years. While Mr. Fetter claims that the PGE PCAM prevents the Company from recovering all of its prudently incurred costs, he was unaware of the fact that PGE has actually over-recovered NPC for

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7/ ICNU/102, Falkenberg/1.
8/ ICNU/105, Falkenberg/1-2.
9/ ICNU/102, Falkenberg/2-4.

the past two years and has experienced earnings at or above its authorized ROE. Mr. Fetter's premise that the Oregon system is unfair to PGE seems to contradict the facts.

Q. WHAT IS THE BASIS FOR MR. FETTER'S RECOMMENDATION TO MODIFY THE PCAM?

A. Mr. Fetter generally argues that changing the PCAM will improve PGE's credit rating, and thus lower capital costs:

> In view of the difficulties that 'BBB'-rated companies faced during the recent financial crisis, I believe it is even more important for the Commission to modify PGE's PCAM to provide for timely recovery of actual fuel and purchased power costs on a timely basis. My recommendation to both the Company and its regulators is to target a return to the 'BBB+' rating level, with a longer term goal of achieving an 'A' category rating, which should alleviate both access and cost pressures related to ongoing financing needs. A key component of the agencies' analysis of the decision in this case will be the manner in which the Commission sets the framework for PGE's PCAM going forward.

PGE/1300, Fetter/14.

Q. DOES MR. FETTER SUGGEST CHANGING THE PCAM WOULD LOWER PGE'S COST OF CAPITAL?

A. He says as much on page 9 of his testimony. Despite this, Mr. Fetter does not seem to believe that modifying the PCAM would reduce PGE's cost of equity:

> I do not believe that providing actual prudent cost recovery on a timely basis represents a reduction in risk that should be reflected in a lower authorized ROE. As I allude to above, consideration of fuel costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States.

PGE/1300, Fetter/20.

I will take Mr. Fetter's word for this, though other witnesses may question it. If true, however, it provides little reason to implement the suggested changes to the PCAM, as most of PGE's debt costs are locked in, and are independent of the Company's bond rating. PGE workpapers for Exhibit 300, file *Integrated 2008 to 2018 (010910.xls)*.

Only debt costs on new issues would be impacted by an improved bond rating, and to some degree short term borrowing costs. Based on PGE's workpapers, the Company plans [redacted] million in new long term debt issues between 2011 and 2018. Based on the Company's response to ICNU-CUB Data Request No. 45, a single step improvement in the Company's bond rating would produce only a [redacted] to its borrowing costs.[10] This rating improvement would produce only a [redacted] benefit per year in the years ahead. It would have little or no impact on test year revenue requirements.

Q. HOW DOES THIS POTENTIAL SAVINGS COMPARE TO THE COMPANY'S OVERALL NET POWER COSTS?

A. Based on the Company's April 1, 2010 filing, the Company expects overall NPC of $740 million in 2011. Consequently, these interest cost savings would amount to [redacted] of the Company's annual power costs. This means, that if the requested PCAM changes were to result in the Company increasing NPC by just 1%, (due to the greater likelihood of recovery resulting in less attention to cost control) the potential cost of the PCAM modifications would outweigh the benefits by [redacted]. Both the PGE assumption about improved bond ratings and the possibility of NPC cost increases are hypothetical. However, this analysis shows that there is far more risk that ratepayer costs will increase due to the PCAM modifications than would be saved by potential reductions in borrowing costs. In the end, the problem with a PCAM is that it removes some of the incentive for cost control, and makes the utility less sensitive to costs because the costs are paid with *Other People's Money*. With the potential benefits being quite small and questionable, there is little basis for the Commission to accept this "bargain."

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[10] ICNU/106, Falkenberg/3.

Q. WHAT OTHER BASIS DOES MR. FETTER USE TO SUPPORT THE PGE PROPOSAL?

A. Mr. Fetter argues that the PGE PCAM mechanism "differs from mainstream regulatory practice, and thus places the Company at a competitive disadvantage in attracting capital in the current economic environment." PGE/1300, Fetter/4.

Q. HAS THE COMMISSION ALREADY CONSIDERED THESE ARGUMENTS?

A. Yes. In UE 180, the Company presented a report from NERA that purported to show that most U.S. utilities had a PCAM, or the equivalent.[11/] In addition, Mr. Fetter ignores the fact that PGE has both a PCAM and an Annual Update Tariff, which shields PGE from risk.

Q. DOES PGE HAVE A MORE FAVORABLE POWER COST RECOVERY MECHANISM THAN OTHER NORTHWEST UTILITIES?

A. Yes. PGE has the Annual Update Tariff ("AUT") and the PCAM. Other major utilities in the Northwest do not have both arrangements. PacifiCorp has the Transition Adjustment Mechanism, which has some similarity to the AUT, but no PCAM in Oregon. In Washington PacifiCorp has neither a PCAM or AUT type mechanism. In Washington Puget Sound Energy and Avista do have PCAMs, but both have deadbands, and neither Company has a mechanism like the AUT to provide annual NPC baseline updates. Thus, contrary to Mr. Fetter's assertions, the fact that PGE has both an AUT and a PCAM puts it at a competitive advantage.

Q. WHAT ELSE DID PGE ARGUE IN UE 180?

A. PGE argued against a broad deadband in its proposed PCAM, partly on the basis of the impact on credit ratings. The Commission noted these issues in Order No. 07-015, in UE

11/ Re PGE, Docket No. UE 180, Order No. 07-015 at 18 (Jan. 12, 2007).

180, when it implemented the current PGE PCAM.[12/] In particular, the Commission noted that arguments concerning bond ratings were made by PGE, and that it was pointed out in the record that PGE had edited a then recent Standard and Poor's ("S&P") report in a self-serving manner.[13/] Mr. Fetter stated he had no knowledge of this event in his response to ICNU-CUB Data Request No. 28.[14/] Further, while Mr. Fetter cites reports from various financial entities and companies that sell bond ratings (such as S&P and Merrill Lynch), he made no effort to determine if any of the reports were influenced by PGE.[15/] Further, the documents provided in response to ICNU-CUB Data Request No. 58 suggest that PGE employees continue to share numerous documents with S&P and Moody's and have very close personal contact with these firms. It certainly appears PGE would still have ample opportunity and ability to influence personnel at those firms in a self-serving manner. In light of the history of the various bond rating and financial firms being influenced by PGE and Mr. Fetter's failure to investigate these issues, his testimony is unpersuasive.

Q. HAS MR. FETTER PRESENTED A BALANCED VIEW OF THE FINANCIAL COMMUNITIES' VIEW OF THE PGE PCAM?

A. No. Mr. Fetter suggests the financial community views the current PCAM as a detriment to PGE's credit quality. For example, on pages 18-19, he cites statements by Bank of America and Wells Fargo as evidence. However, Mr. Fetter failed to point out that Moody's has stated the following:

[redacted]

12/ Id. at 20.

13/ Id.

14/ ICNU/102, Falkenberg/5.

15/ ICNU/102, Falkenberg/6-9 (PGE Response to ICNU-CUB DRs 44, 48, and 49).

[redacted]

PGE Response to ICNU-CUB Data Request No. 58, Confidential Attachment 58-A, page 6 (emphasis added).

While the credibility of the credit rating firms and banks is certainly open to debate owing to their role in the recent financial crisis and PGE's history of editing documents produced by S&P, Mr. Fetter fails to provide a balanced presentation.

Q. HAS THE COMPANY OR MR. FETTER ADDRESSED THE COMMISSION'S REASONING IN APPLYING THE PCAM IN UE 180?

A. No. In that case, the Commission stated:

> We conclude that a PCAM should be adopted to *capture power cost variations that exceed those considered part of normal business risk*. In this case, normal business risk for PGE includes all of the circumstances to which it is exposed, such as hydro variability.

Re PGE, Docket No. UE 180, Order 07-015 at 26 (Jan. 12, 2007) (emphasis added)

While ICNU did not agree fully with the Commission's order on those points, the order considered the evidence and arguments carefully, and was a well-reasoned conclusion. There is no basis for the Commission to change its position at this time.

Q. WHAT IS MR. FETTER'S MAIN OBJECTION TO THE CURRENT PCAM STRUCTURE?

A. Mr. Fetter testifies that:

> I firmly believe that the goal of a PCAM should be the timely recovery of all prudent costs expended by a utility for fuel and power supply in furtherance of providing reliable service to its customers. I do not believe that PGE's PCAM meets that standard.

PGE/1300, Fetter/16. Mr. Fetter cites the earnings test and the asymmetrical deadbands as the major shortcomings in the PGE PCAM:

> My difficulties with PGE's current PCAM fall into two areas, both of which cut against the goal of achieving utility recovery of actual prudent costs on a timely basis, while only charging customers for actual prudent costs: 1. the earnings test that the Commission has imposed; and 2. the asymmetric earnings deadband.

PGE/1300 Fetter/16-17.

Q. WERE ISSUES SURROUNDING THE EARNINGS TEST ADDRESSED IN ORDER 07-015?

A. Yes. The Commission considered many issues related to the earnings test, and decided on the current PCAM structure.[16/]

Q. DOES MR. FETTER BELIEVE THE EARNINGS TEST IS NECESSARY?

A. No. Mr. Fetter testifies that the ability to make prudence disallowances provides more than sufficient means for the Commission to compel efficient behavior by the utility:

> I view the earnings test, as structured, as an imperfect attempt to compel appropriate utility behavior, at the expense of sacrificing the goal of recovery of actual prudent costs with customers paying no more, no less. Such a framework ignores the greatest hammer that a utility regulator holds – the authority to review the prudency of a company's resource procurement activities with the ability to disallow imprudent expenditures.

PGE/1300, Fetter/17.

Again, Mr. Fetter makes the rather naïve assumption that by merely having the ability to disallow imprudent costs, regulators can safely assume that utilities will always operate prudently, and as efficiently as possible. He also assumes that in the truncated process of a PCAM, regulators will always be able to detect imprudence, and won't be misled by the utility into believing that imprudent costs incur were actually prudent. This all stems from Mr. Fetter's underlying *presumption* that power costs requested by the utility were prudently incurred.[17/] In reality, Mr. Fetter is proposing a rather lax, laissez-

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[16/] Discussion of various aspects of the earnings test was interspersed throughout pages 19-27 of Re PGE, Docket No. UE 180, Order 07-015 (January 12, 2007).

[17/] PGE/1300, Fetter/23. If one makes that presumption, I see little point in regulation.

faire form of regulation. While that may be pleasing to companies that sell bond rating services or bankers, it is not a satisfactory form of regulatory oversight.

Q IS MR. FETTER'S ASSUMPTION THAT THE "HAMMER" OF A REGULATORY PRUDENCE DISALLOWANCE IS SUFFICIENT TO MOTIVATE PRUDENT AND EFFICIENT BEHAVIOR BY THE UTILITY SUPPORTED BY THE FACTS?

A. No. Oregon utilities should be fully aware of the prudence standard. Indeed, there have been some major prudence disallowances in recent years. In UE 200, for example, the Commission denied recovery of the Rolling Hills wind farm on the basis of imprudence.[18/] In that case, the utility invested over $200 million, and was presumably well aware of the prudence standard. However, that did not prevent PacifiCorp from making imprudent investment decisions.

A second major prudence disallowance resulted from the long Boardman outage that started in late 2005. In Docket UE 196, the OPUC disallowed half of the costs of the Boardman outage ($26.4 million) on the basis of imprudence.[19/] There was also another long outage at the Boardman plant in 2006 for which PGE never sought cost recovery, apparently a self-imposed penalty for imprudence. Consequently, Mr. Fetter's contention that all fuel and purchased power costs are presumed to be prudent[20/] is unsupported by the facts.

18/ "As noted above, SB 838 provides for the recovery of prudently incurred costs attributable to eligible projects through the RAC procedure. Because we find that Pacific Power failed to prove that it prudently acquired the Rolling Hills project, all costs associated with that project are excluded from the RAC cost recovery mechanism." Re PacifiCorp, Docket No. UE 200, Order 08-548, at 20 (Nov. 14, 2008).

19/ Re PGE, Docket No. UE 196, Order 10-051, at 1 (Feb. 11, 2010).

20/ PGE/1300, Fetter/23.

Q. IS THERE ANY OTHER EVIDENCE THAT PRUDENCE DISALLOWANCES DO NOT PROVIDE SUFFICIENT MOTIVATION FOR PRUDENT AND EFFICIENT UTILITY OPERATION?

A. Yes. In UE 191 (2007), the Commission disallowed costs related to forced outages at two PacifiCorp plants on the basis of imprudence.[21/] However, that fact did not motivate improved efficiency by PacifiCorp or PGE if trends in outage rates are any guide. Exhibit ICNU/103, a public record document from Wyoming Docket No. 20000-363-EP-10, shows that in 2009 PacifiCorp's outage rates increased in almost every category as compared to 2008. Both Staff[22/] and ICNU[23/] have recommended disallowances related to specific outages at PacifiCorp plants in 2009 in the current TAM proceeding.

In the case of PGE, the Commission's prior outage disallowance also has failed to spur efficiency or reliability improvements. Based on the Monet workpapers filed by the Company in this case, the 2009 outage rates for Boardman and Colstrip 4 were substantially increased from prior years. Confidential Exhibit ICNU/104 shows these results. Despite the OPUC's specific reliance on the prudence standard and outage rate disallowance, there has not been a trend in improvement in plant reliability. While an increasing trend in outage rates is not evidence of imprudence, it does show that efficiency has not improved and that causes of outages should be investigated.

Q. PGE DOES NOT OPERATE THE COLSTRIP PLANT. DOES THAT UNDERMINE YOUR ARGUMENT STATED ABOVE?

A. No. It actually illustrates a flaw in Mr. Fetter's assumption. The plant operator is to a large extent immune from the impact of disallowances made by the OPUC in a PGE case.

21/ Re PacifiCorp, Docket No. UE 191, Order, 07-446 at 20 (Oct. 17, 2007).

22/ Re PacifiCorp, Docket No. UE 216, Staff /100 Brown/22.

23/ Re PacifiCorp, Docket No. UE 216, ICNU/100, Falkenberg/5.

Consequently, it is incorrect to assume that prudence disallowances can motivate prudent behavior for plants operated by another company, such as Colstrip.

Q. WHY DOES MR. FETTER OBJECT TO THE ASYMMETRICAL DEADBAND?

A Mr. Fetter testifies:

> I believe the asymmetric deadbands exacerbate the problem. I have difficulty understanding why PGE, or any regulated utility, should absorb some portion of power costs, prudently incurred for the purpose of providing reliable customer service, and upon which the Company receives no return, just reimbursement. To make matters worse, that deadband is then skewed against the interest of the Company and its investors.

PGE/1300, Fetter/18.

Again, it appears Mr. Fetter considers prudence the only standard applicable to the determination of rates. He completely fails to address the Commission's reasoning in its adoption of the current deadband structure:

> CUB cites testimony from docket UE 165, PGE's application for deferral of power costs in a year with insufficient hydroelectric power, to show that replacement costs in poor hydro years will outweigh the benefits of additional power in good hydro years, indicating the need for asymmetrical deadbands.

<u>Re PGE</u>, Docket No. UE 180, Order 07-015, at 23 (Jan. 12, 2007).

> Second, we will set a deadband so that PGE will absorb some normal variation of power costs. We are persuaded by CUB's arguments, in this case and in dockets UE 165 and UM 1187, that an asymmetric deadband is necessary to ensure that the PCAM is revenue neutral.

<u>Id.</u> at 26.

Again, there was ample consideration of the deadband in Order 07-015, and the issue was fully explored in that case. Mr. Fetter has really added nothing new to the discussion, and failed to even address the basis for the Commission's decision.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The current PGE PCAM is not one that ICNU supported originally, nor would have designed for the Company. However, the Commission fully considered all relevant arguments in UE 180 and reached a well-reasoned decision. Mr. Fetter has not pointed out any serious flaw in the Commission's reasoning, nor has he presented any actual evidence of harm to the Company resulting from the decision. Mr. Fetter fails to provide persuasive arguments to change the PCAM as requested by the Company in this case. I recommend the Commission reject PGE's proposal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)
	)

ICNU/101

QUALIFICATIONS OF RANDALL J. FALKENBERG

June 4, 2010

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 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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

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	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	Electric Co.	Philadelphia Economics of nuclear generating units.
3/85	Case No. 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 Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/ 613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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 Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of

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Date	Case	Jurisdict.	Party	Utility	Subject
					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.
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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 Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost

Expert Testimony Appearances of Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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
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

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case
04/08	07-035-93	UT	CCS	PacifiCorp	Power Cost Modeling
07/08	UE 200	OR	ICNU	PacifiCorp	Renewable Adjustment Clause
08/08	20000-315 -EP-08	WY	WIEC	PacifiCorp	Power Cost Adjustment Mechanism
01/09	20000-333 -ER-08	WY	WIEC	PacifiCorp	Power Cost Modeling/Wind resource prudence
02/09	08-035-38	UT	CCS	PacifiCorp	Power Cost Modeling/Wind resource prudence
04/09	UM 1355	OR	ICNU	PGE/PacifiCorp	Outage Rate Modeling
04/09	UM 1396	OR	ICNU	PGE/PacifiCorp	Avoided Costs
06/09	UE 199	OR	ICNU	PacifiCorp	Power Cost Modeling
07/09	UE 207	OR	ICNU	PacifiCorp	Power Cost Modeling
07/09	UE 208	OR	ICNU	PGE	Power Cost Modeling
07/09	UE 210	OR	ICNU	PacifiCorp	Transition Adjustment Mechanism
10/09	UM 1442/ 1443	OR	ICNU	PGE/PacifiCorp	Avoided Costs
10/09	09-035-23	UT	OCS	PacifiCorp	Power Cost Modeling
12/09	UM 1465		ICNU	PacifiCorp	Power Cost Deferral
1/10	20000-352-ER-09	WY	WIEC	PacifiCorp	Power Costs, Wind Resources
2/10	09-084-U	AR	AEEC	Entergy AR	Rate Spread, Formula Rate Plan
3/10	20000-363-ep-10	WY	WIEC	PacifiCorp	PCAM
4/10	10-035-13	UT	OCS	PacifiCorp	Power impact of Major Plant Additions

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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	)
Request for a General Rate Revision.	)
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ICNU/102

PGE RESPONSES TO ICNU-CUB DATA REQUESTS
(RESPONSE TO ICNU-CUB 57 EXCERPTED)

June 4, 2010

April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 036

Request:

Mr. Fetter testifies on page 15 "There was no need for forecasted levels to be locked into base rates as the sole means of cost recovery, because under the Michigan PCAM the companies knew they had an obligation to carry out their fuel procurement and purchased power activities prudently – and when they didn't, they knew they would be subject to a financial disallowance."

a. Doesn't Mr. Fetter agree that if a utility does not have a PCAM, it will bear all of the costs of imprudent fuel or purchased power procurement, while a Company that has a PCAM has the possibility of recovery of imprudent costs if regulators fail to detect such costs, or can be persuaded the costs were not really imprudent?

b. In light of the answer to the question above, doesn't Mr. Fetter agree that a utility stands a better chance of avoiding adverse consequences from imprudent costs with a PCAM than without a PCAM?

Response:

PGE objects to this data request on the grounds that it is compound, hypothetical, vague and ambiguous. Without waiving these objections, Mr. Fetter responds as follows:

a. No. The question assumes that regulators will not catch and disallow imprudent costs. As stated in Mr. Fetter's testimony, the goal of utility regulation is the timely recovery of all costs prudently expended by a regulated utility to provide reliable service to customers at a reasonable cost. See PGE Exhibit 1300, p.4.

b. No.

April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 033

Request:

Is Mr. Fetter aware the in the first two PCAM filings, the Company over-collected NPC and did not have to refund all of the over-collection to customers?

Response:

Mr. Fetter has not reviewed historic PCAM filings. Regardless of what has occurred with regard to PGE's PCAM filings and refunds or collections, Mr. Fetter believes that PGE's actual, prudently incurred fuel and power costs should be fully recovered on as timely a basis as possible. Mr. Fetter's testimony about the systemic problems with the current PCAM and the potential effect of those systemic problems on investors' views of PGE is summarized in his testimony, PGE Exhibit 1300, pages 16-23.

April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 034

Request:

Is Mr. Fetter aware the in the 2009 PCAM filing, the Company over-collected NPC and did not have to refund any of the over-collection to customers?

Response:

Mr. Fetter has not reviewed PGE's 2009 PCAM filing. Regardless of what has occurred with regard to PGE's PCAM filings and refunds or collections, Mr. Fetter believes that PGE's actual, prudently incurred fuel and power costs should be fully recovered as timely a basis as possible. Mr. Fetter's testimony about the systemic problems with the current PCAM and the potential effect of those systemic problems on investors' views of PGE is summarized in his testimony, PGE Exhibit 1300, pages 16-23.

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April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 035

Request:

Is it Mr. Fetter's view that for the past two years, PGE's inability to earn its allowed return was due to the PCAM, and under-collections of NPC? Please explain.

Response:

Mr. Fetter has not analyzed the relationship between past collections of NPC and PGE's actual earnings in past years. His testimony about the systemic problems with the current PCAM and the potential effect of those systemic problems on investors' views of PGE is summarized in his testimony, PGE Exhibit 1300, pages 16-23.

April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 028

Request:

Is Mr. Fetter aware that in a recent PGE general rate case, discovery responses revealed that one of the rating agencies allowed PGE to edit reports and insert language into the report which was supportive of one of PGE's regulatory requests?

Response:

PGE objects to this data request on the grounds that it is overly broad, not reasonably calculated to lead to the discovery of admissible evidence, and assumes facts not in evidence. Without waiving these objections, Mr. Fetter responds as follows:

No.

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April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 044

Request:

PGE/1300, page 14. Mr. Fetter notes that in S&P's downgrade of PGE, it cited a weak PCAM. Prior to the time of filing his testimony, had Mr. Fetter inquired with S&P or to PGE as to whether PGE had requested or suggested that such language be inserted into the S&P report? Please identify the steps taken by Mr. Fetter to ensure that PGE did not influence the text of any reports from S&P.

Response:

No.

April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 048

Request:

PGE/1300, page 18. Mr. Fetter cites a passage of report from Merrill Lynch, Bank Of America.

a. Prior to the time of filing his testimony, had Mr. Fetter inquired with Merrill Lynch or to PGE whether PGE had requested or suggested that such language be inserted into the report? Please identify the steps taken by Mr. Fetter to ensure that PGE did not influence the text of any reports from Merrill Lynch.

b. Same passage. Does Mr. Fetter agree that one of the factors in the Oregon regulatory climate cited by the referenced Merrill Lynch report was the prior ownership of PGE by Enron?

c. Has Mr. Fetter made any attempt to determine how detrimental the Enron ownership was to PGE in terms of its overall credit rating?

d. Does Mr. Fetter believe that the fact that PGE was owned by a parent company that was involved in fraud and criminal activity provides a good reason for regulators to exercise an extra degree of regulatory scrutiny?

Response:

PGE objects to this data request on the grounds that it is overly broad, seeks information that is irrelevant and is not reasonably calculated to lead to discovery of admissible evidence. Without waiving these objections, PGE responds as follows:

a. No.

b. Mr. Fetter agrees that the following was stated in the December 16, 2009 Bank of America Merrill Lynch research report:

> Investment positives
> 1) Improving regulatory environment
> POR has come a long way from being a subsidiary of Enron Corp. to the independent utility it is today. The regulatory environment in Oregon historically has been challenging for utilities, which is understandable given the previous parent company. That said, recent developments in Oregon regulation have been constructive. The OPUC allows a forward test year and recently granted sales decoupling, albeit to a limited extent. The forward looking test year allows POR to earn full returns on its major future projects. We would be much more constructive if the Commission fixed the PCAM.

c. No. However, Mr. Fetter believes that PGE's prior ownership is not relevant to PGE's PCAM structure.

d. Mr. Fetter believes that the PCAM framework should achieve the goal of utility regulation: timely recovery of all costs prudently expended by a public utility to provide reliable service to customers at a reasonable cost. Mr. Fetter believes prior ownership of PGE is irrelevant to the appropriate PCAM framework.

April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 049

Request:

PGE/1300, page 19. Mr. Fetter cites a passage of a report from Wells Fargo. Prior to the time of filing his testimony, had Mr. Fetter inquired with Wells Fargo or PGE as to whether PGE had requested or suggested that such language be inserted into the report? Please identify the steps taken by Mr. Fetter to insure that PGE did not influence the text of any reports from Wells Fargo.

Response:

No.

April 30, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 057

Request:

PGE 1300/page 3. Please provide a copy of each of the prior testimonies listed on this page.

Response:

Attachment 057-A provides the requested information. It is provided electronically (CD) only due to email capacity restrictions.

PREPARED TESTIMONY OF

STEVEN M. FETTER

PRESIDENT

REGULATION UnFETTERED

SEPTEMBER 12, 2007

Chairmen and Members of the Joint Committee. I appreciate the opportunity to share my experiences related to utility adjustment mechanisms, or trackers, here in Indiana and elsewhere in the US, from my perspective as former chairman of the Michigan Public Service Commission and also as former head of the utility credit ratings practice at Fitch. [My full professional and educational background is presented in Attachment SMF-1.]

Fuel adjustment clauses, or FACs, were the earliest utility tracking mechanisms. While there are instances of FAC-like devices dating back to World War I, the trend toward inclusion by regulators of such mechanisms within utility tariffs began in earnest during the 1970's in the face of escalating and volatile oil prices. Over the next thirty years, regulators or legislators in a majority of the states adopted some form of FAC suited to the characteristics of the utilities located within their jurisdiction. While restructuring at first affected the number of states utilizing FACs, with a few states deciding to forgo such mechanisms in of reasons, their most important purpose is to communicate to investors the credit strength of a company or the underlying credit quality of a particular debt security issued by that company.

It is a well-established fact that a utility's credit ratings have a significant impact as to whether that utility will be able to raise capital on a timely basis and upon favorable terms. As respected economist Charles F. Phillips stated in his treatise on utility regulation:

> Bond ratings are important for at least four reasons: (1) they are used by investors in determining the quality of debt investment; (2) they are used in determining the breadth of the market, since some large institutional investors are prohibited from investing in the lower grades; (3) **they determine, in part, the cost of new debt, since both the interest charges on new debt and the degree of difficulty in marketing new issues tend to rise as the rating decreases**; and (4) they have an indirect bearing on the status of a utility's stock and on its acceptance in the market.[9] [Emphasis supplied.]

Thus, the lower a regulated utility's credit rating, the more the utility will have to pay to raise funds from investors to carry out its capital-intensive operations – and, as noted by Dr. Phillips, credit ratings can also affect the amount of money that utilities can raise from equity investors at any point in time. In turn, the ratemaking process factors the cost of capital for both debt and equity into the rates that consumers are required to pay. Thus, a

9 Phillips, Charles F., Jr., The Regulation of Public Utilities, Arlington, Virginia: Public Utilities Reports, Inc., 1993, at p. 250. See also Public Utilities Reports Guide: "Finance," Public Utilities Reports, Inc., 2004 at p. 6-7 ("Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid.").

utility with strong credit ratings is not only able to access the capital markets on a timely basis at reasonable rates; it also is able to share the benefit from those attractive interest rate levels with customers through lower utility rates.

With the increased injection of market forces into utility commodity markets and the recent rapid escalation in fuel, purchased power and natural gas costs, FACs/GCAs have been more important than ever. They have allowed utilities to receive recovery for their prudent fuel, purchased power and natural gas supply expenditures in timely fashion, securing their ability to maintain their financial standing. Conversely, during the past several years, industry observers have also seen that attempts by regulators or elected officials to artificially hold the line on seemingly prudently incurred fuel, purchased power and natural gas cost recovery solely because those costs were growing at a rapid rate could have very dire consequences. I believe everyone here is familiar with the California energy crisis, where a mismatch between wholesale costs and retail rate recovery drove one regulated utility into bankruptcy and a second one up to the edge. Similarly, just one state away from here in Illinois, Commonwealth Edison, one of the country's largest utilities, saw its seemingly strong "A-" credit rating fall into "junk bond" status within a two-and-a-half year period due to political wrangling and uncertainty with regard to timely recovery of its prudent costs of operation. There is no doubt in my mind that the use of trackers where appropriate, with some means of reviewing and monitoring prudence, represents beneficial policymaking that will help to avoid negative financial impacts on regulated utilities and their customers.

The concept of utility regulation is to provide a surrogate for the competitive market that is not present when a company possesses monopoly or near-monopoly status with regard to an essential good, such as utility service. Trackers attempt to align the costs that a utility is required to expend by law or regulation with its recovery of those costs on a timely basis.

Base rate cases with their high expense – for all participants -- and lengthy duration are ill-suited to deal with costs that 1) can vary widely from year-to-year; 2) are substantially outside the control of the utility; and 3) represent a considerable financial outlay by a utility, with no ability to receive a real return on those expended funds. Trackers are clearly more efficient in providing timely recovery of prudent expenditures related to such costs, as well as providing “closer-in-time” price signals to customers.

Moreover, the presence of a legislatively-set mechanism for ongoing monitoring of the ups and downs of utility earnings – the “earnings cap,” a unique feature of Indiana regulation -- complements well the use of trackers in Indiana, as together they track the positive and negative movement of both income and expenses. Indiana's "earnings cap," while not perfect (because it compares the utility's current earnings to outdated authorized earnings), nevertheless provides a protection for customers that utilities are not "overearning," and that cost tracking mechanisms are not enabling overearning. The presence of such a "check" on utility earnings in this state should work to greatly reduce concern that tracking mechanisms are too one-sided toward utility interests. The result has been that Indiana has been able to be a leading jurisdiction in the use of trackers for following actual costs up and down. That said, there are many capital investments and expenses that are not subject to tracking and, thus, there will continue to be a place for rate cases within this state as necessary. As a former policymaker involved in such issues in both the executive and legislative branches of state government, I see a framework here that indicates a fair balancing of interests, within which consideration of additional areas that would benefit from the use of trackers would not be out of place.

In closing, it is wholly consistent with rational utility economics for customers to pay the actual prudently incurred costs of utility service, whether those costs are in an escalating mode or actually going down. Trackers seek to achieve that goal – by allowing recovery of actual incurred costs, both increasing and decreasing, on a timely basis. This in turn helps to ensure the financial stability of Indiana's regulated utilities – a status which benefits all utility stakeholders within the regulated utility process.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)
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ICNU/103

PACIFICORP RESPONSE TO WEIC DATA REQUEST

June 4, 2010

20000-363-EP-10/Rocky Mountain Power
February 16, 2009
WIEC 1st Set Data Request 1.17

WIEC 1st Data Request 1.17

Please provide a narrative explanation and a reconciliation of why PacifiCorp's coal generation during 2009 was lower than it was during 2008.

Response to WIEC Data Request 1.17

The planned outage activities on the PacifiCorp coal plants during 2009 ended up being 0.53% higher than in 2008. Even though there were more planned outage activities scheduled for the year (a 17% increase over 2008) the actual planned outage losses ended up being higher than expected due to extensions and other unforeseen problems. The forced outage losses for 2009 out-paced those of 2008 by 1.45%, creating the largest single difference in loss categories between the two years. Three of the Company's own units and one participating unit experienced significant forced outages as an appendage to the scheduled overhaul activities which accounted for 1.09% in forced outage losses. The maintenance outage losses were also up .55% from the previous year. A combination of less available energy from coal, more energy produced by wind, and a lower overall demand for energy contributed to less production from the Company's coal system for calendar year 2009. The table below contains a tabulation of all comparative losses between calendar years 2008 and 2009.

PacifiCorp Owned Coal-Fired System Losses		
Category of Losses	Calendar Year 2008	Calendar Year 2009
Planned Outages	3.03%	3.56%
Maintenance Outages	1.08%	1.63%
Forced Outages	3.37%	4.82%
Planned Derates	0.22%	0.34%
Maintenance Derates	0.68%	0.43%
Forced Derates	2.83%	3.19%
Total Losses	11.21%	13.97%

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)
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ICNU/104

CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER
BOARDMAN/COLSTRIP OUTAGE RATES

REDACTED

June 4, 2010

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)
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ICNU/105

PGE RESPONSE TO ICNU-CUB DATA RESPONSE

June 4, 2010

April 27, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU-CUB Data Request
Dated April 15, 2010
Question No. 056

Request:

Has Mr. Fetter done any analysis to determine whether the OPUC Staff conducts audits of the PGE PCAM in accordance with the proposals listed in the NARUC Rate Case and Audit Manual?

Response:

No.

itself or does it use an outside contractor? What is the cost effectiveness of this decision? Have there been an increasing number of complaints relative to inaccurate meter readings?

Similar questions could be asked of any number of maintenance related items. What is the utility's tree trimming policy? What is the average period between major and minor generating plant overhauls? What policy exists relative to testing for leaks in water lines?

Insurance and Security Costs

Nationally, the utility industry is incurring increased costs for insurance and security of its facilities and operations. However, the auditor should still inquire as to what the utility is doing in an attempt to mitigate these increases. Has self-insurance been considered? Has there been a review of historically incurred costs, to see if current reserves for property damage can be reduced? Have higher deductibles or a different level of coverage been considered?

Furthermore, the auditor should inquire into the general proactive measures that have been instituted by the utility in order to limit damages or problematic situations. The cost of these measures should also be examined for reasonableness and to make sure that the additional actions are warranted. Examples of items to examine include: additional screening of employees, additional security equipment at critical facilities (e.g., central offices, water treatment facilities, dams, or substations), or the creation or major revision of emergency management procedures. Quite often one insurance policy will extend coverage to utility operations, headquarters, affiliates, and deregulated operations. The auditor should review the policies, determine who and what is covered, and evaluate how the costs are assigned. Even if there is no incremental insurance or security cost to cover non-utility operations, evaluate the benefits received and determine the proper sharing and allocation of costs to all entities covered by the policy/security.

Fuel, Purchased Power, and/or Natural Gas Costs

For many electric utilities, the cost of fuel and purchased power can be the largest single expense and in some cases, well exceeds fifty percent of a utility's total operating expenses. Therefore, these costs warrant some special attention either in general rate proceedings or separate proceedings related to the review of costs included in fuel, purchased power, and natural gas cost recovery rate mechanisms.

To begin, the auditor will want to become generally familiar with the utility's general operation. Does the utility have its own natural gas wells used for providing retail gas service, or does it purchase its natural gas on the open market? What is its policy for purchasing contract gas versus using gas from storage versus buying spot market gas? Or, for an electric utility, is all of the power purchased in the open market, or does it own its own power plants, or is there a mix? Are purchase contracts long term or, as for many cooperatives, all requirement contracts?

After reaching a basic understanding, the auditor will want to explore specific cost aspects of not only contracting for the fuel or purchased power, but also issues of transport of the fuel or power (i.e., wheeling costs, pipeline transport, train tariffs); inventory costs and arrangements (i.e., gas storage or coal inventory levels); and measurement (e.g., where is the power metered, who reads and maintains that meter – the buyer or seller; how often are scales calibrated, etc).

From there, the auditor may wish to examine some of the actual contracts and billings from the utility's wholesale suppliers. Do these match the entries in the utility's ledgers and expense accounts? Is the fuel being provided within the heat content and moisture content specifications contained in the contract? One might want to look at reports on the testing of samples of the delivered fuel to verify that tests are being done to assure that the utility is receiving the quality of fuel for which it pays. In another area, one might want to see if any escalators in the contracts have been properly computed and documented. If the fuel or generation is purchased from an affiliate, determine if the purchase price is appropriate. Should it be priced at cost plus a return or at market price? Could it be purchased less expensively from a non-affiliated entity?

Salaries and Benefits

Salaries and benefits are a major expense for most utilities, and there are many aspects of salaries and benefits that can be explored during an audit.

To start, the auditor may wish to discuss with the utility general policies of the company relative to salaries. Are there automatic increases annually? Are increases merit based or cost of living based? How do the salary policies for management differ from those of non-management? What are the general benefits provided to employees (e.g., health care, 401K, pensions)? These discussions will provide some background to then look at more specifics of the costs. It is also useful to understand how the compensation plan has changed, if it has, compared to recent periods. For example, many utilities have in recent years implemented incentive plans wherein a portion of an employee's salary is tied to performance (e.g., bonuses). One would want to ask when this incentive was developed, and how the performance standards are determined. The auditor should find out whether his/her Commission has allowed incentive costs to be included in setting rates. Are cost savings from the condition that created the incentive included in the test year?

Once one has obtained a background of how the compensation plan for the utility works, it then behooves the auditor to find out how reasonable this plan is and one way to start is to ask the company how it determines that salaries remain in a reasonable range. Are salary surveys of others in the industry used to benchmark ranges of salaries? Are general salary surveys used to look at the regional salaries for various employee classifications (e.g., linemen, accountants, drafters, etc.)? Another more broad way to look at salaries is to do some comparison of costs on a per customer basis among utilities of similar characteristics, and see if anything appears to be out of place and worth investigating. Perhaps one company will have more employees at lower

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
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PORTLAND GENERAL ELECTRIC	)
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Request for a General Rate Revision.	)
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ICNU/106

CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER
PGE RESPONSE TO ICNU-CUB DATA REQUEST

REDACTED

June 4, 2010

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)

OPENING TESTIMONY OF DR. ALAN ROSENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 4, 2010

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Alan Rosenberg. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri. My qualifications are described in Exhibit ICNU/201.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric Company ("PGE" or the "Company").

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A. My testimony first addresses PGE's marginal cost of service study ("MCOS") with a particular focus on its computation of marginal production costs, and its allocation of marginal transmission costs. The second section of my testimony addresses the manner in which PGE applied the results of its MCOS in developing its proposed ratespread, i.e., the allocation of its requested increase among the various rate classes.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/201 through ICNU/207.

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. I strongly support the principle that rates should primarily be based upon the costs that the service imposes on the utility. That is why the MCOS should not only be as accurate as possible, but the ratespread and rate design should follow the indications of the MCOS as closely as possible, with the proviso that rate shock should be avoided. While the filed MCOS is far superior to PGE's previous studies in that it more faithfully depicts the connection between customer behavior on the margin, it can be improved upon. With regards to the allocation of the increase, I find that PGE's proposal diverges more than necessary from the marginal cost principles that govern the ratemaking philosophy of the Oregon Public Utility Commission ("OPUC" or the "Commission"). I will provide my suggested allocation of the increase, assuming, first, that the Company MCOS is accepted as filed, and second, that my recommended change to the MCOS is accepted.

The Need for Cost-Based Rates

Q. DO YOU SUPPORT THE PREMISE THAT RATES SHOULD BE DESIGNED TO REFLECT, AS ACCURATELY AS POSSIBLE, THE COSTS THAT THE CUSTOMERS' SERVICE IMPOSES ON THE UTILITY?

A. Yes. The quintessential rationale for regulation in the first place is to act as a proxy or surrogate for competition, when authentic competition is not feasible. Competition is thought to drive rates down to cost of service (when cost of service is defined to include a reasonable rate of return) because a provider that overcharges any of its customers will soon lose those customers to a competitor. Thus, the overarching principle of regulation is that it tries to emulate competition by setting rates based on cost. Although factors such as simplicity, gradualism, economic development and ease of administration may also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class. In fact, in my experience, virtually every regulator of which I am aware mandates that the utility file some type of cost of service analysis.

Q. WHAT ARE THE ADVANTAGES OF COST-BASED RATES?

A. Besides being true to the rationale for utility regulation, rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions (i.e., how much energy to consume, at what rate, and when) they tend to take actions which not only minimize their own costs, but those of the utility as well, thereby benefitting all customers.

Q. HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A. To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve them—no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. Thus, almost by definition, non-cost-based rates lead to cross-subsidization. In my experience, most customers neither desire to be subsidized, nor do they consider it fair or just if they are forced to subsidize others.

Q. HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A. Rate design is the process of translating the cost of providing service for each customer class into per unit charges that recover the targeted revenue requirement for each class. It is important that the proper amounts and types of costs be allocated to the appropriate customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the demand, energy, and customer costs are properly reflected in the demand, energy and customer components of the rate schedules, respectively, customers are provided with the appropriate price signals to manage their loads accordingly. This, in turn, provides the correct signal to the utility about the need for new investment to meet the customers' needs. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand, and the energy charge that they pay should reflect the cost of providing that energy.

From a rate design perspective, overpricing one portion of the rate (i.e., energy) and underpricing the other components of the rate, such as customer and demand charges, will result in a disproportionate share of revenues being collected from high load factor customers and send distorted price signals to all customers.

Q. HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A. Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on the cost to serve them do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q. PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable and transparent means of determining future levels of power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate utility-wide cost changes into changes in the rates applicable to customer classes and to particular customers within each class. For the customer, this situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for the level of future power costs that the customer will incur.

The Marginal Cost of Service Study and Reconciliation Process

Q. WHAT IS A MARGINAL COST OF SERVICE STUDY?

A. A witness for PGE in UM 827, Dr. Heathie Parmesano put it this way:

> A marginal cost study should answer the question: How would the utility's costs change if it were to supply an additional kWh or kW at a particular time or service an additional customer? The study is forward looking and must take into account the practices and planning standards of the particular utility, as well as its incremental structure and cost of capital, regulatory constraints, tax liabilities, etc.

Re PGE, OPUC Docket No. UM 827, Order 98-374 at 5 (Sept. 11, 1998).

I think that is as good an answer as any.

Q. WHAT DO YOU MEAN BY RECONCILIATION?

A. Because the sum of the marginal costs will almost certainly differ from the embedded revenue requirement, the use of an MCOS requires an additional step in order to reconcile the marginal costs with the revenue to be collected from each class. In Oregon, the policy since 1998 has been to perform this reconciliation by function, i.e., the marginal production costs are reconciled to the embedded cost of production, the marginal transmission costs are reconciled to the embedded cost of transmission, and so on and so forth.

Q. WHY IS A MARGINAL COST STUDY IMPORTANT?

A. The Commission has consistently upheld the principle that rates should be predicated on cost of service. Specifically, after investigating various methods of determining marginal costs, the Commission made this observation:

> Since 1974, the Commission has used marginal costs as one of the principal factors for spreading revenue requirement among customer classes. Order No. 74-658. Historically, we have reconciled the two so that each customer class pays an equal percentage of marginal costs. Adopting this stipulation will change the allocation method to equal percentages of marginal cost by function. This new approach will improve our historical efforts to allocate cost responsibility to customer classes in ways that lead to more efficient price signals for customers and efficient use of electrical service. It will also improve fairness in our rates by ensuring that the costs of one function (e.g., distribution) do not affect the allocation of the costs of another function (e.g., generation). Finally, adopting this stipulation will provide us valuable information when we consider whether and how electric service should be provided on an unbundled basis.

Re PGE, OPUC Docket No. UM 827, Order 98-374 at 5 (Sept. 11, 1998).

Q. MSSRS. KUNS AND CODY MENTION THAT THEY HAVE BEEN WORKING WITH STAKEHOLDERS REGARDING MARGINAL COST AND RATE-SPREAD ISSUES SINCE PGE'S LAST RATE APPLICATION, UE 197. HAVE YOU PARTICIPATED IN THOSE EFFORTS?

A. Yes, I have actively participated in the UM 1415 workshops with PGE, Staff, CUB and other interested parties. While complete agreement was not reached on each and every issue, I believe that the parties engaged in a worthwhile exchange of ideas and that a consensus was reached on some overarching principles, for example, the decision to introduce the incremental or marginal cost of production entailed by increases in coincident demands. This price signal was completely lacking in previous PGE studies. It is this improvement that is primarily responsible for the superior relevance of the current study. However, I do not recall much discussion, let alone agreement, on ratespread issues—although PGE did provide examples of how the ratespread would derive from the new cost analysis using PGE's allocation methods from the previous case.

Q. HOW DID PGE CALCULATE THE MARGINAL COST OF PRODUCTION CAPACITY?

A. PGE used the levelized fixed cost of a simple cycle combustion turbine ("SCCT"), which is normally considered the least expensive way to secure firm capacity. The Company also added 12% to that since its planners require a 12% reserve margin. This means that the consequences of each 1 megawatt ("MW") of incremental peak demand (at the generation level) requires building of 1.12 MW of capacity. Finally, the Company also included the fixed cost of securing a firm supply of gas for the SCCT. These assumptions are all in accord with PGE's Integrated Resource Plan ("IRP").

Q. WERE THERE OTHER RELEVANT CHANGES TO THE MARGINAL STUDY THAT WERE RAISED IN THE UM 1415 WORKSHOPS?

A. Yes. In the previous cost studies, the marginal energy costs were predicated in some fashion on the Mid-C market prices. In this study, the Company is using long-run real levelized marginal energy costs derived from a combined cycle combustion turbine (CCCT), based on a long-term gas price forecast, and including a $30 per ton CO_2 compliance cost. Also, it is my understanding that Mssrs. Kuns and Cody considered all capitalized costs of the CCCT above those of an SCCT (or "peaker") to be energy related, and also considered the costs of wind farms to be energy related. The second noteworthy change is that, at the insistence of Staff, the marginal costs of transmission were treated as though they were generation related. As a result, 69% of the costs of the transmission were considered as though they were energy related, even though 100% of the costs of the transmission plant are totally fixed and not at all variable.

Q. DO YOU HAVE CONCERNS ABOUT THESE LAST TWO CHANGES?

A. Yes. First, I am of the view that marginal energy costs should be based on short-run marginal costs, as this is the most immediate and direct consequence to the Company's cost structure. Second, long-run price forecasts often turn out to be unreliable. For example, right now forecasts on CO_2 compliance costs could be as little as $15 per ton. Even the Company concedes this in its 2009 IRP:

> *At the same time,* ***there is unprecedented uncertainty about the timing, form and cost of potential greenhouse gas legislation; the price for natural gas; and the ultimate impact of renewable energy standards on availability, cost*** *and quality of renewable resources.*

PGE 2009 IRP at 1 (emphasis added).

Third, even if the utility can spend more on fixed production costs to save fuel by investing in a more capital intensive technology (such as building a CCCT instead of an SCCT), once the new generating plant runs past the break-even point—the point at which the fuel savings outweigh the additional capital costs—any additional hours are irrelevant to the choice of technology. Put another way, once the break-even point is reached, the marginal cost of energy beyond the break-even point is simply the running costs of the baseload plant. Fourth, I do not agree that wind resources are 100% energy related. Even the Western Electricity Coordinating Council allows a wind resource to count 5% of the nominal capacity towards its capacity reserve. Finally, I disagree that transmission and generation are completely interchangeable and thus reject the notion that transmission responds to energy and demand in the same manner as generation. Transmission lines are rated in terms of capacity and all transmission costs are fixed and not variable.

Q. WHAT IS THE END RESULT OF THE COMPANY'S MARGINAL COST DETERMINATIONS?

A. The end result is that, even without including the supposed "energy" cost of transmission, PGE implies an annual average marginal cost of energy of $79.24 per MWh. This figure is almost 20% higher than the value used in PGE's last marginal cost study, conducted just two years ago. Moreover, energy prices have come down from their 2008 levels. In my view, this figure of $79.24 per MWh is simply unrealistic.

Q. OTHER THAN THE CONCERNS YOU PREVIOUSLY LISTED, WHY DO YOU BELIEVE THIS FIGURE TO BE UNREALISTICALLY HIGH?

A. The Energy Trust of Oregon ("ETO") identifies a levelized cost of $65.00 per MWh as the cost-effective threshold for energy efficiency measures. Anything above that threshold is not considered to be cost-effective and should not be pursued. I might add that Mssrs. Kuns and Cody seem skeptical of their own marginal energy cost, because they are proposing even lower energy charges (for supply) than those currently in effect. ICNU/202, Rosenberg/4.

Q. HOW WOULD YOU PROPOSE TO MODIFY THE COMPANY'S MCOS TO REFLECT THAT REALITY?

A. I have adjusted each of the hourly marginal energy costs down by a uniform percentage so that the average cost over all hours is $65.00 per MWh. I will call this the "Modified MCOS" to distinguish it from the "Company MCOS." When discussing PGE's proposed ratespread, and my recommended ratespread, I will benchmark both with the Modified MCOS as well as with the Company MCOS, so that the Commission can see the difference. Lowering the marginal energy cost is appropriate, because PGE's marginal costs should not exceed the threshold for cost-effectiveness.

Q. ARE YOU PROPOSING OR RECOMMENDING ANY OTHER CHANGES TO THE COMPANY'S MCOS?

A. No, not with the study's findings or allocation of the marginal costs per se. I still have some qualms that the study overemphasizes the role of pure energy in cost causation, but the limitation of the marginal energy costs to $65.00 per MWh will suffice as a corrective measure. However, I would recommend two adjustments with how the marginal costs *are reconciled* to PGE's embedded revenue requirement.

Q. PLEASE EXPLAIN THESE TWO ADJUSTMENTS.

A. The Company has two categories of sunk costs that are outside the scope of the normal marginal costs, i.e., they do not fit neatly into marginal energy costs, marginal demand costs or marginal customer costs. Consequently, these costs were never discussed or addressed in the UM 1415 workshops. Nevertheless, the Company includes these costs in its revenue requirement, and so, if approved, they still need to be collected. Specifically, the Company is requesting the collection of over $51 million in Franchise and OPUC fees and $3.5 million in Trojan decommissioning costs.

Q. HOW DOES THE PGE STUDY ALLOCATE THE FRANCHISE AND OPUC FEES?

A. The Company allocates these costs on the basis of current revenue. Although the witnesses do not explicitly justify this particular process, it seems obvious that they are treating these fees as sort of an overhead adder to all other costs. While that is a perfectly reasonable position, current revenues are <u>not</u> the most appropriate metric to use if one takes that approach. Clearly, proposed revenues would be superior because those would be the revenues that prevail once this case concludes. However, because: (a) the proposed revenues cannot be calculated until we do allocate these fees, and (b) ideally, the proposed revenues would be equal to the totality of true marginal costs, I adjusted my

MCOS so that the Franchise and OPUC fees are allocated on the subtotal of all the *other* costs included in the MCOS.

Q. HOW DOES THE PGE STUDY ALLOCATE THE TROJAN DECOMMISSIONING COSTS?

A. The Company allocates these sunk costs on the basis of busbar energy.

Q. DO THE WITNESSES ATTEMPT TO JUSTIFY OR RATIONALIZE THIS ALLOCATION?

A. No.

Q. DO YOU AGREE WITH THEIR TREATMENT OF THESE COSTS?

A. No.

Q. PLEASE EXPLAIN THE BASIS OF YOUR DISAGREEMENT ON THIS ISSUE?

A. Setting aside for the moment whether the Company will actually spend $3.5 million to remedy this ill-fated project, there are at least two reasons why the Company’s treatment is inappropriate. The first is that its method is the most distortive. These costs are absolutely fixed, so to attribute these costs to the energy usage—undoubtedly the most elastic portion of the rate structure—is the most injurious to the marginal price signal. In the second place, their method is contrary to Oregon policy. The policy of the Commission is that when reconciling the embedded revenue requirement with marginal costs, one must respect each function. Since the Trojan plant was production related, any decommissioning costs are also production related. Consequently, these costs should be treated no differently from any other production costs.

Q. AT THIS POINT COULD YOU SUMMARIZE THE DIFFERENCES BETWEEN YOUR MODIFIED MARGINAL COST STUDY, RECONCILED TO THE EMBEDDED REVENUE REQUIREMENT, WITH THAT OF THE COMPANY?

A. Yes. First, I proportionally reduced the marginal energy costs to reach the $65.00 per MWh threshold of cost-effective energy efficiency measures identified by the ETO.

Second, I allocated Franchise and OPUC fees in proportion to the sum of the other reconciled marginal costs.

Third, I allocated Trojan's decommissioning costs on the basis of total production costs, rather than busbar energy.

Q. SHOULD THE COMMISSION DECIDE WHICH MARGINAL COST STUDY TO USE BASED UPON THE OUTCOME OF THE STUDY?

A. No. The primary objective of a cost study is to measure cost responsibility as accurately as possible. Of course, the Commission may choose to temper the implications of the approved cost study for reasons of gradualism or other policies in the public interest. Nevertheless, those considerations should not be a reason to compromise the cost of service principles used in the study.

<u>Ratespread -- The Process by Which the Revenue Requirement is Spread Among the Rate Schedules</u>

Q. IS THERE ANY DISAGREEMENT ON THE PRINCIPLE THAT RATES SHOULD BE ALIGNED WITH MARGINAL COST, AS NEAR AS CAN BE DONE WITH AVOIDANCE OF DISRUPTIVE RATE INCREASES?

A. I do not believe so.

Q. ON PAGE 6 OF THEIR TESTIMONY, MSSRS. KUNS AND CODY STATE THEY ARE NOT PROPOSING ANY FORM OF RATE MITIGATION OR OTHER DEVIATION FROM USING MARGINAL COST TO SPREAD THE REVENUE REQUIREMENT. IS THAT A CORRECT STATEMENT?

A. No, that is not a correct statement. In fact, that is precisely the result of the Customer Impact Offset ("CIO") that they propose on that very page, as PGE acknowledges in its response to ICNU Data Request No. 063.

> **The application of the CIO**, which the witnesses regard as part of the rate design process, **results in prices that deviate from straight marginal cost allocation.**

ICNU/203, Rosenberg/2 (emphasis added).

Q. HOW FAR DOES THE COMPANY'S PROPOSED RATESPREAD DEVIATE FROM A STRAIGHT MARGINAL COST ALLOCATION?

A. For some customers, it deviates quite a bit. This is shown on Exhibit ICNU/204. It can be seen, for example, that for the large (over 4 MW) Subtransmission customers, the proposed rates are almost 11% above cost of service, even as measured by the Company proffered study. Exhibit ICNU/205 shows the results of the Company ratespread proposal as measured by the Modified MCOS. As can be seen here, measured by this more accurate analysis, the rates are even more skewed away from cost of service.

Q. ARE THERE OTHER CONCERNS RAISED BY YOUR EXHIBITS ICNU/204 AND ICNU/205?

A. Yes. The Company supplied sufficient granularity for us to distinguish Rate Schedule 89 into five distinct subgroups, differentiated by both service voltage (Secondary, Primary, and Transmission), and by size (those with peak demands less than 4 MW, and those over 4 MW). Consequently, I have prepared my exhibits with that detail, because voltage level and size influence cost of service.

Turning to Exhibit ICNU/204 we see, for example, that the larger (over 4 MW) Schedule 89 customers taking service at Primary level are being priced, at PGE's proposed rates, 5% above their cost of service, while the corresponding smaller customers are being priced 3% below their cost of service. A similar disparity is also exhibited as measured by the modified cost study, as shown on Exhibit ICNU/205.

Q. WHAT DO THOSE DISPARITIES INDICATE?

A. These disparities are indicative of a problem with the Company's proposed rate design. It is the rate design, i.e., the level of the customer charge and the various demand and energy charges, that will determine the revenue contribution of these class subgroups. Consequently, I recommend that when the Company constructs its final rates in this case, care is taken to make sure that there are no **intraclass** subsidies deriving from their rate design.

Q. DO YOU OPPOSE ANY TYPE OF CIO MITIGATION PROCESS?

A. No, I do not oppose some sort of mitigation process. It is not out of the ordinary for commissions to temper the results of strictly applying a cost study in order to moderate increases. In fact, I do not object to the stated objectives of the witnesses to limit the increases for any of the major rate schedules (which the panel defines as Schedules 7, 15, 32, 83, 85, 89, 91 and 92) to a single digit increase, i.e., less than 10%, and to limit the increase for any rate schedule to no more than 15%. The rates for some classes have diverged from cost of service by so much that it requires a somewhat larger increase to effect any significant improvement.

Q. WHERE THEN DO YOU DIFFER FROM THE COMPANY POSITION ON THE CIO?

A. I take issue with the application of the process. First, the Company seems to disallow any decreases. I see nothing improper or inappropriate if a class is deserving of a decrease. Certainly, no customer would object to its own rate decrease, so there is no concern on customer impact from that score. Second, the Company reallocates the shortfall, resulting from a cap, to only some rate classes and exempts others.

Q. HOW DOES THE COMPANY RATIONALIZE EXEMPTING SOME CLASSES FROM A REALLOCATION OF THE CIO SHORTFALL AND NOT OTHERS?

A. The witnesses seek to rationalize this selective reallocation on the grounds that those classes are receiving an "above average increase."

Q. WHY DO YOU DISAGREE WITH THAT REASONING?

A. In essence, the Company is penalizing those classes, such as Rate Schedule 85 and Rate Schedule 89, simply because those classes are deserving of a less than average increase (or even a decrease). Of course, those classes are only getting a less than average increase because these same customers were being overcharged, relative to cost of service, at current rates. Thus, the Company proposal is adding insult to an existing injury. Furthermore, if the CIO shortfall is only distributed selectively, then clearly those targeted classes must diverge more from cost than if the shortfall were distributed over a larger group. Thus, the Company method of reallocating the CIO shortfall results in more distortion than if the shortfall were to be spread over all customers who are below their cap.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE CIO PROCESS?

A. Yes. In reviewing the Company's rate design, I noticed inordinately high increases to the Direct Access customers. For example, the Primary Schedule 489 customers would see increases of around 70% or even higher. Upon further investigation, it appears that the culprit is a proposed increase of almost 400% in the System Usage Charge.

Q. WHAT IS CAUSING SUCH AN ENORMOUS INCREASE IN THE SYSTEM USAGE CHARGE?

A. Approximately half of the new System Usage Charge is attributable to Franchise Fees and the other half to the CIO shortfall.

Q. WHAT COULD BE DONE TO AMELIORATE THIS DISRUPTIVE INCREASE?

A. Franchise fees and CIO shortfalls are not attributable to any single function nor can they be considered a marginal energy cost in any way, shape or form. My recommendation is that the System Usage Charge be abolished and that any revenues that it would have collected instead be collected in the less sensitive components of the rate, such as the customer charge and/or the first block of the distribution facility capacity charge. Another alternative would be to proportionally increase all other charges in the rate. Either way would be superior to the proposed System Usage Charge in the sense that it would be less distortive or disruptive.

Q. IF YOU WERE TO ALLOCATE THE REQUESTED INCREASE BASED ON YOUR REFORMULATION OF THE CIO PROCESS, AS YOU HAVE JUST DESCRIBED, WHAT WOULD BE THE RESULT?

A. The result using the Company cost of service study and reconciliation process is shown on Exhibit ICNU/206. The result using my recommended Modified MCOS and reconciliation is shown on Exhibit ICNU/207.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
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PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)

ICNU/201

QUALIFICATIONS OF DR. ALAN ROSENBERG

JUNE 4, 2010

Qualifications of Dr. Alan Rosenberg

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Dr. Alan Rosenberg. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and am a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I was awarded a Bachelor of Science Degree from the City College of New York in 1964 and a Doctorate of Philosophy in Mathematics from Brown University in 1969. Subsequently, I held an Assistant Professorship of Mathematics at Wesleyan University in Connecticut. In the summer of 1975, I was a Visiting Fellow at Yale University. From July, 1975 through January, 1981, I was Assistant Controller and Project Manager for a division of National Steel Products Company. My responsibilities there included supervision of management accounting, cost accounting and data processing functions. I was also responsible for internal control, general ledger systems, working capital levels, budget preparation, cash flow forecasts and capital expenditure analysis.

I have published in major academic journals and am a member of the International Association for Energy Economics. I was an invited speaker at the NARUC Introductory Regulatory Training Program and a panelist at a conference on LDC and Pipeline Ratemaking sponsored by the Institute of Gas Technology. I have presented a paper on stranded costs at the 21st Annual International Conference of the International Association for Energy Economics. I have had two papers on transmission congestion pricing and one paper on reorganizing markets published in *The Electricity Journal*. I am also a Certified Energy Procurement Professional by the Association of Energy Engineers. In January, 1982, I joined the firm of Drazen-Brubaker & Associates, Inc., the predecessor of Brubaker & Associates. Since that time, I have presented expert testimony on the subjects of industry restructuring, open access transmission, marginal and embedded class cost of service studies, prudence and used and useful issues, electric and gas rate design, revenue requirements, natural gas transportation issues, demand-side management, and forecasting.

I have previously testified before the Federal Energy Regulatory Commission as well as the public service commissions of Arizona, Connecticut, Delaware, Florida, Idaho, Illinois, Iowa, Massachusetts, Michigan, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, Vermont, Virginia, Wyoming and the Provinces of Alberta, British Columbia, New Brunswick, Nova Scotia, and Saskatchewan in Canada. I have also testified before the Michigan Senate Technology and Energy Committee.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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ICNU/202

PGE RESPONSE TO ICNU DATA REQUEST QUESTION NO. 136, ATTACHMENT 136-A

JUNE 4, 2010

April 23, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU Data Request
Dated April 15, 2010
Question No. 136

Request:

Please provide a schedule or table showing the percentage increase (or decrease) proposed for each of the various charges for Rate Schedule 89.

Response:

Please see PGE Attachment 136-A for the requested analysis.

UE 215
Attachment 136-A

Analysis

Schedule 89 Current and Proposed Monthly Prices

Secondary Delivery Voltage	Units	Price Current	Price Proposed	Pct. Change
Basic Charge	Bills	$150.00	$1,310.00	773.3%
Transmission & Related Services Charge	$/kW	$0.70	$0.88	25.7%
Facility Capacity Charge				
First 1,000 kW	$/kW faccap	$1.90	$1.77	-6.8%
1,001 to 4,000 kW	$/kW faccap	$0.57	$1.77	210.5%
Over 4,000 kW	$/kW faccap	$0.57	$0.38	-33.3%
Distribution Demand Charge	$/kW	$2.01	$2.05	2.0%
Energy Charge				
On-peak	mills/kWh	68.98	63.24	-8.3%
Off-peak	mills/kWh	54.46	51.45	-5.5%
System Usage Charge	mills/kWh	1.05	4.27	306.7%
Reactive Power Charge	$/kVar	$0.50	$0.50	0.0%
Schedule 111	mills/kWh	0.01	0.00	-100.0%
Schedule 121	mills/kWh	0.55	0.00	-100.0%
Schedule 122	mills/kWh	2.26	0.00	-100.0%
Schedule 125	mills/kWh	(3.70)	0.00	-100.0%

Primary Delivery Voltage	Units	Price Current	Price Proposed	Pct. Change
Basic Charge	Bills	$220.00	$1,040.00	372.7%
Transmission & Related Services Charge	$/kW	$0.70	$0.85	21.4%
Facility Capacity Charge				
First 1,000 kW	$/kW faccap	$1.67	$1.73	3.6%
1,001 to 4,000 kW	$/kW faccap	$0.34	$1.73	408.8%
Over 4,000 kW	$/kW faccap	$0.34	$0.34	0.0%
Distribution Demand Charge	$/kW	$2.01	$1.98	-1.5%
Energy Charge				
On-peak	mills/kWh	66.60	61.36	-7.9%
Off-peak	mills/kWh	52.74	49.57	-6.0%
System Usage Charge	mills/kWh	0.84	4.03	379.8%
Reactive Power Charge	$/kVar	$0.50	$0.50	0.0%
Schedule 111	mills/kWh	0.02	0.00	-100.0%
Schedule 121	mills/kWh	0.52	0.00	-100.0%
Schedule 122	mills/kWh	2.15	0.00	-100.0%
Schedule 125	mills/kWh	(3.53)	0.00	-100.0%

Subtransmission Delivery Voltage	Units	Price Current	Price Proposed	Pct. Change
Basic Charge	Bills	$1,000.00	$2,020.00	102.0%
Transmission & Related Services Charge	$/kW	$0.70	$0.84	20.0%
Facility Capacity Charge				
First 1,000 kW	$/kW faccap	$1.67	$1.73	3.6%
1,001 to 4,000 kW	$/kW faccap	$0.34	$1.73	408.8%
Over 4,000 kW	$/kW faccap	$0.34	$0.34	0.0%
Distribution Demand Charge	$/kW	$1.00	$0.91	-9.0%
Energy Charge				
On-peak	mills/kWh	64.80	60.54	-6.6%
Off-peak	mills/kWh	51.63	48.75	-5.6%
System Usage Charge	mills/kWh	0.71	3.89	447.9%
Reactive Power Charge	$/kVar	$0.50	$0.50	0.0%
Schedule 111	mills/kWh	0.05	0.00	-100.0%
Schedule 121	mills/kWh	0.51	0.00	-100.0%
Schedule 122	mills/kWh	2.09	0.00	-100.0%
Schedule 125	mills/kWh	(3.43)	0.00	-100.0%

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY	)
	)
Request for a General Rate Revision.	)

ICNU/203

PGE RESPONSE TO ICNU DATA REQUEST QUESTION NO. 063

JUNE 4, 2010

March 31, 2010

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to ICNU Data Request
Dated March 24, 2010
Question No. 063

Request:

On page 6 of PGE Exhibit 1500, the witnesses state that they do not propose any form of rate mitigation or other deviation from marginal costs to spread the revenue requirement. However, in the same sentence the witnesses state that they do propose to employ the Customer Impact Offset after spreading the revenue requirement to temper the rate impacts to certain schedules.

a. **Is it the witnesses' opinion that the CIO does not result in a deviation from marginal costs? If yes, please provide a mathematical proof that it does not so result. If the answer to this question is no, please quantify the deviation of the proposed revenues of each class from the revenue target that would result from a strict marginal cost ratespread using the approved reconciliation process.**
b. **Please explain the difference between "rate mitigation" and "deviating from marginal cost to temper rate impacts."**
c. **Please fully explain how the witnesses arrived at the particular parameters they employed to limit the marginal cost based rate spread in the CIO, e.g., the 2.0 times the average increase for some rate schedules, the 1.25 times the average increase for other schedules, and the 9.5 cents per kWh. If these parameters were mandated by previous Commission orders, please cite to those orders and pertinent page numbers.**

Response:

a) PGE objects to this request as vague and ambiguous. Subject to and without waiving its objection, PGE responds as follows:
PGE does not know what ICNU means by the "approved reconciliation process."

It is the witnesses' assertion, as stated in testimony, that the CIO occurs after spreading the unbundled revenue requirement based on marginal costs. The application of the CIO, which the witnesses regard as part of the rate design process, results in prices that deviate from a straight marginal cost allocation. Please reference page 10 of PGE Exhibit 1503 for the magnitude of the CIO by class

b) In the context provided, the two phrases can be used interchangeably.

c) The particular parameters were based on the judgment of the witnesses. Please reference PGE Exhibit 1500 page 32, line 18 to page 33, line 23 for further discussion. While PGE is aware of the Commission's adoption of rates developed using similar parameters, PGE is not aware of any ongoing Commission mandate.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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	)
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ICNU/204

COMPARISON OF COMPANY MARGINAL COSTS AND COMPANY PROPOSED REVENUES

JUNE 4, 2010

Portland General Electric
Comparison of Company Marginal Costs
and Company Proposed Revenues

Line	Schedule	Marginal Costs[1] ($000) (1)	Proposed Revenue[2] ($000) (2)	(Over) / Under Collection (3)	Percent Difference (4)
1	**Schedule 7**	$886,977	$887,004	($27)	0.00%
2	**Schedule 15**	$4,548	$4,605	($57)	-1.25%
3	**Schedule 32**	$160,044	$160,044	($0)	0.00%
4	**Schedule 38**	$5,532	$4,647	$885	16.00%
5	**Schedule 47**	$4,865	$3,021	$1,844	37.91%
6	**Schedule 49**	$13,316	$6,723	$6,593	49.51%
7	**Schedule 83**	$218,153	$213,481	$4,672	2.14%
8	**Schedule 85**	$237,538	$242,389	($4,851)	-2.04%
	Schedule 89 1-4 MW				
9	**Secondary**	$48,762	$50,002	($1,240)	-2.54%
10	**Primary**	$48,684	$47,113	$1,571	3.23%
11	**Total**	$97,446	$97,115	$330	0.34%
	Schedule 89 GT 4 MW				
12	**Secondary**	$2,032	$1,931	$101	4.99%
13	**Primary**	$128,939	$135,039	($6,100)	-4.73%
14	**Subtransmission**	$32,433	$35,691	($3,257)	-10.04%
15	**Total**	$163,405	$172,661	($9,255)	-5.66%
16	**Schedule 91**	$18,323	$18,482	($159)	-0.87%
17	**Schedule 92**	$378	$399	($21)	-5.59%
18	**Schedule 93**	$121	$108	$13	10.65%
19	**Total**	$1,810,647	$1,810,681	($34)	0.00%

Source/Notes:

[1] UE 215 / PGE Exhibit / 1503 Kuns-Cody / 1

[2] UE 215 / PGE Workpaper Kuns-Cody / 1500

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)

ICNU/205

COMPARISON OF MODIFIED MARGINAL COSTS AND COMPANY PROPOSED REVENUES

JUNE 4, 2010

Portland General Electric
Comparison of Modified Marginal Costs and Company Proposed Revenues

Line	Schedule	Modified Marginal Costs ($000) (1)	Proposed Revenue[1] ($000) (2)	(Over) / Under Collection (3)	Percent Difference (4)
1	**Schedule 7**	$888,216	$887,004	$1,212	0.14%
2	**Schedule 15**	$4,542	$4,605	($63)	-1.39%
3	**Schedule 32**	$160,204	$160,044	$160	0.10%
4	**Schedule 38**	$5,569	$4,647	$922	16.56%
5	**Schedule 47**	$4,928	$3,021	$1,908	38.71%
6	**Schedule 49**	$13,532	$6,723	$6,809	50.32%
7	**Schedule 83**	$218,549	$213,481	$5,068	2.32%
8	**Schedule 85**	$237,365	$242,389	($5,024)	-2.12%
	Schedule 89 1-4 MW				
9	**Secondary**	$48,498	$50,002	($1,505)	-3.10%
10	**Primary**	$48,835	$47,113	$1,722	3.53%
11	**Total**	$97,332	$97,115	$217	0.22%
	Schedule 89 GT 4 MW				
12	**Secondary**	$2,075	$1,931	$144	6.94%
13	**Primary**	$128,230	$135,039	($6,809)	-5.31%
14	**Subtransmission**	$31,305	$35,691	($4,386)	-14.01%
15	**Total**	$161,610	$172,661	($11,051)	-6.84%
16	**Schedule 91**	$18,299	$18,482	($183)	-1.00%
17	**Schedule 92**	$377	$399	($22)	-5.92%
18	**Schedule 93**	$122	$108	$14	11.10%
19	**Total**	$1,810,646	$1,810,681	($34)	0.00%

Source/Notes:
[1]UE 215 / PGE Workpaper Kuns-Cody / 1500

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
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Request for a General Rate Revision.	)

ICNU/206

ICNU RECOMMENDED RATESPREAD
USING COMPANY MARGINAL COST STUDY AND RECONCILIATION

JUNE 4, 2010

Portland General Electric
ICNU Recommended Ratespread
Using Company Marginal Cost Study and Reconciliation

Line	Schedule	Current Rate Class Revenue[1] ($000) (1)	ICNU Recommended Ratespread ($000) (2)	Increase / (Decrease) ($000) (3)	Percent Difference (4)
1	**Schedule 7**	$814,982	$892,347	$77,365	9.5%
2	**Schedule 15**	$4,515	$4,564	$49	1.1%
3	**Schedule 32**	$147,875	$161,082	$13,207	8.9%
4	**Schedule 38**	$4,046	$4,650	$605	14.9%
5	**Schedule 47**	$2,630	$3,023	$393	14.9%
6	**Schedule 49**	$5,811	$6,680	$868	14.9%
7	**Schedule 83**	$195,372	$214,803	$19,431	9.9%
8	**Schedule 85**	$229,215	$239,731	$10,516	4.6%
	Schedule 89 1-4 MW				
9	**Secondary**	$48,101	$49,406	$1,306	2.7%
10	**Primary**	$45,550	$49,319	$3,769	8.3%
11	**Total**	$93,650	$98,725	$5,075	5.4%
	Schedule 89 GT 4 MW				
12	**Secondary**	$1,768	$1,944	$176	9.9%
13	**Primary**	$133,504	$130,956	($2,548)	-1.9%
14	**Transmission**	$34,390	$33,286	($1,104)	-3.2%
15	**Total**	$169,662	$166,186	($3,476)	-2.0%
16	**Schedule 91**	$18,124	$18,397	$273	1.5%
17	**Schedule 92**	$392	$382	($10)	-2.6%
18	**Schedule 93**	$94	$109	$14	14.9%
19	**Total**	$1,686,369	$1,810,681	$124,312	7.4%

Source/Notes:
[1]UE 215 / PGE Exhibit / 1503 Kuns-Cody / 10

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
	)
Request for a General Rate Revision.	)

ICNU/207

ICNU RECOMMENDED RATESPREAD USING MODIFIED MARGINAL COST STUDY AND RECONCILIATION

JUNE 4, 2010

Portland General Electric
ICNU Recommended Ratespread
Using Modified Marginal Cost Study and Reconciliation

Line	Schedule	Current Revenue[1] ($000) (1)	ICNU Recommended Ratespread ($000) (2)	Increase / (Decrease) ($000) (3)	Percent Difference (4)
1	**Schedule 7**	$814,982	$894,386	$79,404	9.7%
2	**Schedule 15**	$4,515	$4,561	$46	1.0%
3	**Schedule 32**	$147,875	$161,391	$13,516	9.1%
4	**Schedule 38**	$4,046	$4,653	$607	15.0%
5	**Schedule 47**	$2,630	$3,025	$395	15.0%
6	**Schedule 49**	$5,811	$6,683	$872	15.0%
7	**Schedule 83**	$195,372	$214,913	$19,541	10.0%
8	**Schedule 85**	$229,215	$239,765	$10,549	4.6%
	Schedule 89 1-4 MW				
9	**Secondary**	$48,101	$49,033	$933	1.9%
10	**Primary**	$45,550	$49,361	$3,811	8.4%
11	**Total**	$93,650	$98,394	$4,744	5.1%
	Schedule 89 GT 4 MW				
12	**Secondary**	$1,768	$1,945	$177	10.0%
13	**Primary**	$133,504	$129,977	($3,527)	-2.6%
14	**Transmission**	$34,390	$32,110	($2,279)	-6.6%
15	**Total**	$169,662	$164,032	($5,629)	-3.3%
16	**Schedule 91**	$18,124	$18,388	$263	1.5%
17	**Schedule 92**	$392	$381	($11)	-2.8%
18	**Schedule 93**	$94	$109	$14	15.0%
19	**Total**	$1,686,369	$1,810,681	$124,312	7.4%

Source/Notes:
[1] UE 215 / PGE Exhibit / 1503 Kuns-Cody / 10