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August 19, 2005

Via Electronic and US Mail

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

Re: In the Matter of PACIFIC POWER & LIGHT Application for Power Cost Adjustment Mechanism
Docket No. UE 173

Dear Filing Center:

Enclosed please find an original and six copies of the Direct Testimony of Randall J. Falkenberg and Exhibits ICNU 101-106 on behalf of the Industrial Customers of Northwest Utilities in the above-captioned proceeding.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided.

Thank you for your assistance.

Sincerely,

/s/ Sheila R. Ho
Sheila R. Ho

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony of Randall J. Falkenberg and Exhibits ICNU 101-106 on behalf of the Industrial Customers of Northwest Utilities upon the parties on the service list, shown below, by causing the same to be mailed, postage-prepaid, through the U.S. Mail.

Dated at Portland, Oregon, this 19th day of August, 2005.

/s/ Sheila R. Ho
Sheila R. Ho

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 173

In the Matter of	)
	)
PACIFICORP	)
	)
Application for Approval of Power Cost	)
Adjustment Mechanism.	)

POWER COST ADJUSTMENT MECHANISM

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

August 19, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

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

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

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit ICNU/101 describes my education and experience within the utility industry. I have more than 25 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear generating plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA, I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc. ("Kennedy"). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Texas, Utah, West Virginia, and Wyoming. Included in Exhibit ICNU/101 is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc. with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY APPEARED IN ANY PROCEEDINGS BEFORE THE OREGON PUBLIC UTILITY COMMISSION?

A. Yes. I have filed testimony in six PacifiCorp proceedings in Oregon: UE 111 in 2000, UE 116 in 2001, UE 134 in 2002 and 2003, UM 995 in 2002, UM 1050 in 2004, and UE 170 in 2005. In those cases, I addressed issues related to power cost modeling, power cost deferrals, prudence on new resources and multi-state jurisdictional allocation. I also filed testimony in five Portland General Electric Company ("PGE") cases: UE 137 and UE 139 in 2002, UE 149 in 2003, UE 161 in 2004, and UE 165/UM 1187 in 2005. In those cases I addressed PGE's Resource Valuation Mechanism ("RVM") and PGE's request for a Power Cost Adjustment Mechanism ("PCAM") and Hydro Generation Adjustment ("HGA").

Q. HAVE YOU APPEARED AS AN EXPERT IN OTHER PROCEEDINGS INVOLVING FUEL OR POWER COST ISSUES?

A. Yes. I have been involved in a number of PacifiCorp proceedings in California, Utah, Washington and Wyoming, where I testified concerning power cost and interstate cost allocation issues. In Texas, I have also been involved in a number of fuel and power cost related cases. Finally, I have appeared in a number of other cases where fuel or purchased power costs were at issue. Exhibit ICNU/101 summarizes the cases in which I have appeared.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I address the issues raised by the PacifiCorp (or the "Company") request for approval of its PCAM. Specifically, I show why the arguments the Company uses in support of this proposal are unpersuasive. I also identify a number of problems and flaws in PCAM proposal. I recommend that the Commission reject the proposed PCAM and identify a number of issues the Commission should resolve prior to authorizing a PCAM.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have concluded as follows:

1. **The Commission should reject the proposed PCAM. PacifiCorp has not demonstrated that a PCAM is needed. The PCAM proposal is poorly explained and not adequately justified in PacifiCorp's testimony. The Company fails to address many problems inherent in the PCAM concept.**

2. **Ms. Omohundro and Mr. Widmer support the PCAM largely on the basis of volatility in power costs and wholesale market prices. However, there is no demonstration by the Company that a PCAM is the best means to address the problem. There simply is not enough justification provided to warrant implementation of such a major change in regulatory policy at this time.**

3. **The Company seeks to implement the PCAM in an opportunistic manner outside of a general rate case. While it argues a PCAM would lower its cost of capital, it did not incorporate this request into its filing in UE 170.**

4. **The Company provides few details regarding how it would coordinate its PCAM with the First Partial Stipulation in UE 170. As a result, costs disallowed in the rate case may still be included in the actual power costs and recovered through the PCAM. The Company also does not address why the PCAM would be necessary if the RVM requested in UE 170 is approved.**

5. **The Company provides no PCAM Tariff and few details concerning how its proposed prudence review would operate.**

6. **PacifiCorp's PCAM will complicate the regulatory process. It would create the need for additional audits to verify actual power costs. Before allowing a permanent PCAM, the Commission should first hold a rulemaking proceeding to develop proper rules, procedures, filing requirements and incentive mechanisms.**

7. **There are several serious design flaws in the proposed PCAM. The proposed PCAM is needlessly complex and inconsistent with the Revised Protocol. It penalizes customers for increased costs due to sales increases, but ignores the accompanying increased sales revenues. There is no dead**

band, and the sharing mechanism is not consistent with past Commission practices. There is no provision for treatment of gas resale revenues.

III. PROBLEMS IN THE PCAM PROPOSAL

Q. SHOULD PACIFICORP'S PCAM BE AUTHORIZED BY THE COMMISSION?

A. No. Adoption of the proposed PCAM would be a questionable policy decision at this time. The Company provides little support for the PCAM. Further, pass through mechanisms reduce incentives for efficiency and increase the overall regulatory burden. Finally, the PacifiCorp proposal is flawed and places ratepayers at a substantial disadvantage vis-à-vis the Company.

Q. ARE THERE IMPORTANT DEFECTS IN THE PCAM PROPOSAL?

A. Yes. There are many policy problems and practical drawbacks with the PCAM proposal. I divide these into two categories: Policy/Support issues, and Design issues. Below I identify the major components of my analysis in both categories:

POLICY/SUPPORT ISSUES:

- Justification/Need for a PCAM;
- Failure To Fully Address Recognized Problems With The PCAM Concept;
- Regulatory Complexity;
- Lack of Formal Rules and Procedures; and
- Lack of Audit/Reconciliation Process.

DESIGN ISSUES:

- PCAM Inconsistency with the Revised Protocol;
- Lack of Dead Band and an Inappropriate Sharing Mechanism;
- Inclusion of Non-Volatile Costs;

- Inequitable Treatment of Sales Variations; and
- Lack of Provision for Gas Resale Revenues.

IV. POLICY/SUPPORT ISSUES

1. Justification/Need for a PCAM

Q. HOW DOES THE COMPANY JUSTIFY ITS REQUEST FOR A PCAM?

A. The Company provides very little support for its PCAM. The total justification for the PCAM amounts to less than three pages of testimony presented by Ms. Omohundro[1/] and five pages from Mr. Widmer.[2/] Ms. Omohundro supports the proposed PCAM as follows: 1) a PCAM is needed due to volatility in power costs; and 2) a PCAM could "positively influence" PacifiCorp's credit rating.

Mr. Widmer justifies the PCAM on the basis that: 1) there is an asymmetric risk associated with power cost uncertainty; 2) PacifiCorp has an Integrated Resource Plan ("IRP"), thus it engages in prudent planning; 3) most utilities in the Western Electricity Coordinating Council ("WECC") have some form of PCAM; and 4) both customers and shareholders may benefit from improved credit ratings.

Neither of these witnesses present any other substantial evidence concerning the need for the PCAM, the inadequacy of PacifiCorp's bond ratings, or any financial difficulties the Company would endure without a PCAM.

Q. PLEASE COMMENT ON THE BOND RATING ISSUE.

A. It would be pure speculation to claim PacifiCorp's bond ratings will actually improve with approval of a PCAM. Ms. Omohundro does not actually testify that

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1/ PPL/100, Omohundro/2-4.
2/ PPL/200, Widmer/2-6.

the Company will experience improved credit ratings. She merely notes that rating agencies have expressed some concern over the lack of a PCAM and loosely suggests that adoption of a PCAM would be a positive influence on the Company's credit rating. PPL/100, Omohundro/3. The same might be said if the Commission simply announced that it planned to increase PacifiCorp's rate of return in its next rate case. However, that would not make it a wise policy decision for the Commission.

Ironically, Mr. Widmer goes much further than Ms. Omohundro when he testifies: "As explained by Ms. Omohundro, a PCAM should enhance the Company's credit quality and lower its cost of borrowing." PPL/200, Widmer/6. It appears that Mr. Widmer is willing to go much further with his interpretation of Ms. Omohundro's testimony, than she was willing to testify in the first place.

Ultimately, the Commission has little to go on with respect to the credit rating issue. Even if the Commission is convinced a credit rating improvement would occur, there are two problems that have not been addressed by the Company. <u>First</u>, without a full blown rate case, the Company would retain the lower cost of capital for itself, offering no direct benefits to ratepayers. Thus, the Company's decision to file its PCAM request many months after it filed its general rate case, appears opportunistic.

<u>Second</u>, there is no evidence produced by the Company to establish that its current credit rating is too low, or how much ratepayers would save from an improved credit rating. The Company offers no "cost-benefit analysis" of this proposed change.

Q. THE OTHER JUSTIFICATION FOR THE PCAM CONCERNS POWER COST VOLATILITY. PLEASE COMMENT.

A. Again, the discussion in Ms. Omohundro's testimony is very broad and general. There is no specific evidence presented to establish that the current level of power cost volatility poses a serious problem for the Company.

Mr. Widmer argues that there is an asymmetric risk of power cost variation because costs might increase to infinity, but can never fall below zero. PPL/200, Widmer/6. However, Mr. Widmer is wrong on both counts. Certainly, power costs cannot increase to infinity (nothing can). However, it would not be impossible for them to become negative. While certainly an extreme possibility, if the Company was "long" on capacity and energy, and the rest of the market very short, it could well make more money on surplus power sales than it spent to produce it. In fact, the Company's own projections showed extremely low, and even negative power costs during the 2001 power crisis. In a presentation made by the Company on April 2, 2001, to the parties in No. UE 122 (another application for a Power Cost Adjustment)[3/], the Company presented a forecast of net power costs for the year 2001. Based on that forecast, for the last five months of 2001, PacifiCorp's net power costs were expected to drop to an annualized level of $257 million. *Even more startling was the Company's projection that net power costs would go into the negative in October 2001, and total a mere $4 million for the last quarter of 2001.*

3/ The Commission denied PacifiCorp's request for a PCA, but has allowed the Company to make a new request for a prospective PCA as part of Docket No. UE 116. OPUC Docket No. UE 116, Special Public Meeting (May 14, 2001).

In any case, it is not the overall distribution of power costs that is the real issue – it is the likelihood of a positive or negative power cost variance (the difference between the power costs reflected in rates, and the actual result) that matters. There is no reason to expect that the Company will consistently under-estimate power costs. Indeed, the Company has the incentive to over estimate its power costs in regulatory proceedings. The Commission, however, has no incentive to authorize power costs that are too low or too high, so there is little reason to fear a "systemic" bias towards under recovery of power costs.

Finally, there is no explanation provided by either Ms. Omohundro or Mr. Widmer as to why it is preferable to saddle ratepayers with power cost risks. A PCAM does not make the risk of power cost volatility go away. It merely allocates that risk to ratepayers instead of shareholders. As Staff witness Mr. Gailbraith recently testified in a PGE proceeding: "It is much more efficient to have the financial market diversity Net Variable Power Cost ("NVPC") risk, than to allocate the risk to customers and have them bear it." Re PGE, OPUC Docket No. UE 165, Staff/100, Galbraith/9.

Q. MR. WIDMER DISCUSSES THE INCREASING COSTS OF HYDRO VOLATILITY AS AN EXAMPLE OF THE PROBLEMS INHERENT IN ESTIMATING FUTURE POWER COSTS. IS HYDRO UNCERTAINTY SUFFICIENT JUSTIFICATION FOR A PCAM?

A. No. The Company currently has a "hydro hedge" as a tool for coping with this problem. Currently PacifiCorp uses such tools for managing its power costs. Market solutions to the problem of power cost volatility are available to the Company. Even if hedges that operate in the precisely the same manner as a PCAM are not available to the Company, there is nothing to suggest it is more efficient for ratepayers to bear the risk than to allow financial markets to operate as intended and diversify those risks.

Q. DOES PACIFICORP ACKNOWLEDGE THE FACT THAT IT HAS ALREADY PROPOSED AN RVM PROCESS THAT WILL PROVIDE THE COMPANY WITH SUBSTANTIAL PROTECTION FROM POWER COST UNCERTAINTY IF IT IS APPROVED?

A. Barely. Mr. Widmer testifies that "Adoption of an annual power cost update certainly moves the distribution of the exposure in the right direction because it eliminates a large portion of recovery lag. However, it does not address net power cost exposure between rate cases." PPL/200, Widmer/5. I certainly hope that the Commission considers this comment in its decision to implement PacifiCorp's requested RVM. In the end, the Company provides nothing more to address the need for both an RVM and a PCAM. Further, the RVM would afford protection between rate cases unless the Company plans to file rate cases more often than its annual RVM updates. Since this is unlikely, Mr. Widmer's statement makes little sense.

Mr. Widmer fails to acknowledge that the proposed RVM would provide substantial protection from market volatility and other factors that produce power cost volatility. With its proposed RVM, PacifiCorp would allowed to re-estimate its variable power costs once per year, and compute the final power costs used in rates (updating the most significant items) as *late as November of each year*. Under the RVM, the power cost estimate would be prepared just two months prior to the rate effective period and none of the underlying data is more than 8-10 months old.

In contrast, without the RVM the situation is less favorable to the Company. Even if PacifiCorp filed a general rate case every year, the power cost estimates reflected in rates could be close to a year out of date by the time rates went into effect. Without an annual rate filing, these costs would remain in effect until the next major rate case was filed. Thus, the RVM would provide the Company with a substantial ability to track and respond to power cost changes over time.

As a result, I believe that the request to implement a PCAM now is merely the next step in an effort to move towards an "exact cost recovery" rider. This is more commonly called "cost-plus" ratemaking.[4/] I may address the RVM issue in more detail at the time of ICNU's supplemental testimony after the Commission issues its order in Docket No. UE 170.

Q. ASSUMING THAT WHOLESALE MARKET VOLATILITY IS HERE TO STAY, IS A PCAM THE BEST MEANS OF DEALING WITH IT?

A. No. In fact, a PCAM might well have the opposite effect. It might shield PacifiCorp from the most serious risks of market volatility to such an extent that the Company does not develop effective long-term solutions to the problem of its dependence upon the wholesale market.

Q. PLEASE EXPLAIN.

A. Ultimately, the best solution to an erratic (and perhaps irrational, or even corrupt) power market may be to limit exposure to it through a portfolio approach. To do so, securing longer-term power supplies may be the best solution. By purchasing,

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4/ I recognize the current PCAM proposal is not for an exact cost recovery rider. However, once approved, a move to exact cost recovery would be a much smaller step to make than the current proposal to implement a PCAM.

leasing or obtaining long-term supply contracts tied to new or existing resources, the Company could reduce its dependence on short-term markets.

The problem with a PCAM is that it may eliminate the most substantial risks to PacifiCorp from its market-based balancing strategy. Thus, implementation of a PCAM could provide PacifiCorp the incentive to continue a potentially more risky strategy of over reliance on the market, and avoid the more risk-averse strategy of building or purchasing the output of new capacity. If the Commission is concerned about that issue, then a PCAM may be exactly the wrong solution to the problem.

Q. HAS PACIFICORP PRESENTED ANY EVIDENCE IN THIS CASE DEMONSTRATING SUSCEPTABILITY TO MARKET PRICE FLUCTUATIONS OR OTHER VARIABLES?

A. No. PacifiCorp has presented no evidence concerning the significance of changes in market prices to overall power costs. Because the Company sells substantial amounts of power, increases in power costs also increase revenues. Thus, there is no proof that high or volatile market prices harm the Company in a substantial way.

Q. DOES THE FACT THAT PACIFICORP HAS AN IRP SUGGEST A PCAM IS WARRANTED?

A. No. I fail to see any nexus between the two. The mere existence of an IRP process does not serve to shift the risks of power supply costs from shareholders to customers. Mr. Widmer suggests that, merely by having an IRP, the Company is prudent in its entire power supply process. PPL/200, Widmer/4. However, an IRP is merely a loose "road map" for the Company's resource procurement process to follow. The execution of that plan requires many steps and choices to be made. At any point along the way, the Company might make bad choices or improper decisions.

2. Failure to Fully Address Recognized Problems with the PCAM Concept

Q. ARE THERE OTHER POLICY ARGUMENTS AGAINST USE OF A PCAM THAT PACIFICORP HAS NOT ADDRESSED?

A. There are important issues the Company has not even considered or addressed in its testimony. For example, a PCAM can cause a major difference between the revenue effects of different kinds of power purchases and the accounting treatment of certain types of costs. Consequently, even if a particular supply strategy has the lowest total cost per kWh (when all costs are included), a higher-cost purchase transaction may be more profitable to the utility. Without a PCAM, the Company has a great incentive to minimize costs between rate cases, and would naturally select the lowest cost supply strategy. With a PCAM, the Company may have a financial incentive to select only purchase transactions that enjoy pass-through recovery, irrespective of total cost.

Examples of this would be the decision to build new capacity, sell existing generators or lease capacity. Resources requiring an increased transmission investment would also be discouraged by a PCAM. Even if the Company could reduce total cost by making a transmission investment, a PCAM could make that a less attractive option than continuation of high-cost purchases.

Likewise, a utility may see no need to mount a legal challenge to unfavorable fuel or power contracts because legal fees are not a pass-through item while fuel is under a PCAM. Reductions in fuel or purchased power expense would be eligible for PCAM recovery and the Company would have a reduced incentive to minimize them because the increased legal fees would reduce earnings, but the reduced fuel costs would have little benefit.

Q. IS THERE EVIDENCE THAT A PASS THROUGH ACCOUNT DISCOURAGES EFFICIENCY?

A. Yes. Exhibit ICNU/102 is a copy of a portion of a presentation made by PacifiCorp concerning a heat rate improvement project. The document strongly suggests that when fuel costs are passed through to customers, there is little incentive for heat rate improvement. Conversely, when the power crisis hit and power costs were not a pass through, the Company initiated a heat rate improvement project. Certainly, if power costs are largely a pass through item, efficiency improvement and capital investments will be discouraged.

3. Regulatory Complexity

Q. WOULD A PCAM COMPLICATE AND INTENSIFY REGULATION?

A. Yes, the presence of a PCAM could (or at least should) greatly complicate and intensify regulatory efforts. This will be manifested as confusion concerning rate case settlements, increased gaming of accounting entries, and the need for more audits.

Owing to the Partial Stipulation in UE 170, there is the possibility that a variety of issues resolved in that case will emerge again. In UE 170, the parties agreed to adjustments totaling $8.0 million on an Oregon basis. Re PacifiCorp, OPUC Docket No. UE 170, First Partial Stipulation at 3 (May 4, 2005). However, there was no specific delineation of any principle or ratemaking theory underlying such adjustments.

Under the PCAM proposal, the Company contends that it will make adjustments to remove costs disallowed in a rate case. The Company cites the SMUD contract as an example.[5/] However, there is no indication PacifiCorp will make any deductions for costs it agreed to remove as part of rate case settlements. Because power cost estimates can be affected by both changes in modeling assumptions, as well as removal of costs, there is ambiguity concerning what issues may or may not have been resolved in a Settlement. For example, if the settlement in the rate case reflected resolution of differing views on GRID input assumptions (i.e. unit capacities, heat rates or outage rates) it might be reasonable to assume that actual costs need not be adjusted for such issues. However, in some cases, (i.e. the Aquila Hydro Hedge, margins on short term firm sales, and contracts where prudence was an issue) parties argued certain costs should be disallowed. Assuming that the Commission accepts "black box" settlements to cases, costs are disallowed, but it is not possible to identify the components that make up the total disallowance.

Unless the same costs are also eliminated from the PCAM actual cost filing, customers could still end up paying for costs already eliminated from base rates in a settlement. This means that there will likely be a substantial debate as to the reasonableness of actual costs requested by the Company. In the end, unless the Commission is prepared to give the Company a "blank check" in the

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5/ Ironically, the Company did not make a disallowance for SMUD in PPL/204, the 2004 "back cast" of the PCAM mechanism. ICNU/105 (PacifiCorp's Response to ICNU Data Request ("DR") No. 1.7). It is safe to assume that the Commission will have to carefully scrutinize the PCAM filings to insure costs disallowed in rate cases are not included in the actual accounts.

PCAM for costs that were opposed in rate cases, the PCAM re-opens many issues already litigated in rate cases.

Q. CAN YOU PROVIDE AN EXAMPLE OF THIS KIND OF PROBLEM BASED ON PPL/204?

A. Yes. PPL/204 is an illustration of the PCAM based on 2004 actual data. The testimony supporting the Stipulation in UE 147 established the net power cost baseline figure of $598 million used in PPL/204. However, the testimony only indicates that the final net power cost figure used in the Stipulation reflects the resolution of several issues, including the Aquila Hydro Hedge. The Stipulation does not address whether those costs were allowed or disallowed. In that case, ICNU and Staff argued the Aquila Hydro Hedge should not be reflected in rates. The Stipulation and supporting testimony do not specify exactly what the treatment of the Aquila Hydro Hedge was in the Stipulation or what it should be in the future.

In the actual cost figures used in PPL/204, costs and receipts related to the Aquila Hydro Hedge are included. Both the Company and various parties would certainly be inclined to argue over whether those items should be reflected in the PCAM. For example, if one assumes the Stipulation disallowed the Aquila Hydro Hedge, one might also conclude costs and receipts should be removed from actual power costs. However, there is no basis in the Stipulation for reaching that conclusion. Because the Stipulation in UE 147 does not resolve the issue, there would be ample room for confusion and controversy regarding this point. Ultimately the Commission might have to "reverse engineer" the "black box" settlement in UE 147 and decide the treatment of the issue as regards actual costs.

Q. WOULD PARTIES HAVE THE OPPORTUNITY TO IDENTIFY SUCH PROBLEMS UNDER THE PACIFICORP PCAM PROPOSAL?

A. That is unclear. Mr. Widmer testifies that a prudence review is contemplated by the Company; however, he provides no details of how this would work. In any case, the issue of reasonableness of costs goes far beyond prudence. The Company has suggested no mechanism for insuring that improperly classified costs, or unreasonable costs may be removed from the PCAM actual cost balance.

Q. ARE THERE OTHER TYPES OF ACCOUNTING ISSUES THAT CAN ARISE WITH A PCAM THAT THE COMPANY HAS IGNORED?

A. Certainly. The issue of the classification of costs from an accounting perspective becomes quite important with a PCAM. Without a PCAM, the utility has little incentive to engage in any accounting subterfuge between rate cases. With a PCAM, classification of costs as part of the pass through account becomes highly profitable. Indeed, this kind of "gaming" creates the need for more, not less, regulatory oversight.

Further, questions of timing of entries can become quite important. Prior period costs might be included as part of the initial set of actual costs included in the PCAM, for example. The Company contends it will remove out of period costs. However, if we learned nothing else from the Bridge Audit, it was that PacifiCorp's books are a confusing morass. In that case, the auditors found substantial issues with respect to the booking of costs into the proper period. In the end, it was impossible to develop a complete and accurate accounting of all prior period costs.

Issues can arise regarding whether various costs are capitalized or expensed. Under a PCAM, the utility would have greater incentive to expense rather than capitalize costs, particularly costs related to fuel supply or storage (assuming they are eligible for recovery). One could reasonably expect PacifiCorp to attempt to broaden the definition of allowable costs to be included in net variable power costs.

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

A. There are many issues that arise concerning the proper accounting of costs for ratemaking purposes when a PCAM is used. In some instances, fraud or criminal activity has been discovered in addition to the many more mundane accounting issues. I have participated in cases where both kinds of issues have arisen. Exhibit ICNU/103 summarizes some of the issues that have arisen in proceedings in which I have participated or am aware of. Some of these issues may be applicable to PacifiCorp and others may not be. However, this list demonstrates the broad scope of issues that can result from a PCAM process.

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

A. Some of the issues are the same as in a general rate case. Certainly, it is safe to assume the OPUC carefully reviews all pertinent information in a rate increase request. I would be quite surprised if the Commission simply adopted an attitude of automatic acceptance of the utility's requested costs. This same attitude and approach must also be applied in relation to costs recovered via a PCAM on a *continuous* rather than *occasional* basis.

In a number of the cases listed in Exhibit ICNU/103, the issues that were contested were *created* by the presence of a PCAM approach. In one case (SPS), the Company created a corporate fuel-purchasing and handling subsidiary (and later sold it). This allowed many base rate items to become part of eligible fuel cost expense. In other cases, there was substantial debate about whether the costs in question were eligible for pass-through accounting, even though they may have been legitimate ratemaking expenses. This is important because a PCAM should not be viewed as a means of obtaining "on the spot" rate treatment for any base rate item that can be disguised as fuel or power cost-related.

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

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

Q. ARE THERE OTHER PROBLEMS WITH THE PCAM PROPOSAL?

A. Yes. The Company proposes an earnings test in relation to accruals made under the PCAM. If the Company is over earning, it would not be allowed to accrue any positive deferrals. If it is under earning, it would not accrue any negative deferrals. This gives rise to the need for audit of the earnings report of the Company. Although utilities frequently file periodic earnings reports with the Commission, traditionally they are not used in setting rates. In this case, the earnings reported could have a direct effect on the rates ultimately charged to customers by the utility. Thus, there should be some form of verification and audit of the earnings report as well. In the end, the PCAM proposal creates the need for at least three new audits—one of actual power costs deferred, one of the PCAM calculation, and one of reported earnings.

4. <u>Lack of Audit/Reconciliation Process</u>

Q. BASED ON THE ABOVE DISCUSSION IT APPEARS THAT A FORMAL AUDIT OR RECONCILIATION PROCESS SHOULD BE USED WITH ANY PCAM. HAS PACIFICORP ADDRESSED THIS ISSUE?

A. No. The Company witnesses provide virtually no explanation of how the PCAM process would actually work. Nor do they even provide a PCAM tariff to define what costs would be included, and which would not. While the Company acknowledges a prudence review would be required, they don't acknowledge any need for an accounting audit to determine whether costs are reasonable ratemaking expenses or eligible for inclusion in the PCAM.

Ordinarily, in states where a permanent PCAM or comparable pass-through mechanism is used, there are detailed rules and procedures that govern the process. For example, Texas fuel cost "reconciliation" cases, where prudence and compliance with the "fuel rule" is verified, are often comparable to a full-blown rate case. Typical "reconciliation" cases take many months to complete, involve dozens of rounds of discovery requests, and often result in hundreds of documents being filed with the Commission.[6/]

Q. WOULD IT BE APPROPRIATE TO IMPLEMENT A PERMANENT PCAM WITHOUT RULES TO GOVERN THE ELIGIBILITY OF COSTS?

A. No. Implementation of a permanent PCAM is a *major* change in regulatory practice for PacifiCorp and regulators. It should not be undertaken without first having a rulemaking proceeding to properly define what expenses are eligible for PCAM recovery. This would naturally involve some considerable regulatory activity and, again, would create *more, not less,* regulatory activity. However, this rulemaking is absolutely necessary if ratepayers are to be protected from paying unreasonable or unverified costs.

Q. WHAT ELSE WOULD BE REQUIRED BEYOND A "FUEL RULE" TO DEFINE ELIGIBLE COSTS AND APPROPRIATE REGULATORY PROCEDURES TO FAIRLY IMPLEMENT A PCAM?

A. There should also be a set of Minimum Filing Requirements ("MFR"). The MFR should require identification of all long generator outages, generator heat rates, capacities, average fuel costs, monthly listings of purchased power contracts, fuel inventory information, and a variety of other data. As part of a rulemaking, an MFR would need to be developed. PacifiCorp's proposal offers no guidance as to what rules it would propose, the full scope of any review process, or what kind of

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6/ Legislation in Texas did away with pass-through accounting for fuel costs after 2001. However, the final fuel reconciliation for utilities took until 2004 to complete.

information it will file when it seeks to change the PCAM. Clearly, the Company would prefer to operate its PCAM with no rules, no standards, no MFRs, and as little oversight as possible.

V. DESIGN ISSUES

1. <u>PCAM Complexity/Revised Protocol Inconsistency</u>

Q. WHY DO YOU CONTEND THAT THE PCAM IS NEEDLESSLY COMPLEX AND INCONSISTENT WITH THE REVISED PROTOCOL?

A. The Company proposes to identify the causes of power cost variations in the actual cost balance, and then allocate those costs to states on the basis of certain allocators. Neither step is necessary to comply with the Revised Protocol. In fact, the Company purposely misapplies the Revised Protocol in its proposed PCAM.

Q. EXPLAIN FURTHER.

A. Under the PCAM proposal, the Company plans to use GRID model studies to determine the cause of power cost variations. <u>See</u> PPL/300, Duvall/3; PPL/204; ICNU/106 (PacifiCorp's Response to ICNU DR No. 1.3). For example, power costs variations related to Company owned hydro would be allocated to Oregon on the basis of the DGP (57.8%) allocation factor. Power cost variations related to the Mid-C contracts would be allocated on the basis of the MC factor (69.7% for Oregon.) Comparable allocators would be applied for the east hydro and existing Qualifying Facilities ("QF") allocators. Most other costs would be allocated on a system basis using the SG factor (28.6% for Oregon).

While Mr. Duvall contends that this process is "designed to [allocate] changes in costs and benefits for these three components in a manner that is consistent with the initial allocation of the costs and benefits under the Revised Protocol" it does not do so. PPL/300, Duvall/3. In fact, the proposal actually deviates from the Revised Protocol.

Q. HOW DOES THE PCAM DEVIATE FROM THE REVISED PROTOCOL?

A. To explain this, I will reference Mr. Duvall's testimony regarding the Revised Protocol:

> Under the Revised Protocol, all costs are allocated consistent with the Company's rolled-in methodology, with four exceptions. The first exception, Seasonal Resources, use monthly-weighted allocation factors, rather than annual allocation factors. While this is a change to the Company's rolled-in methodology, the costs of Seasonal Resources are still allocated on a system-wide basis. The other three exceptions result from the application of the Embedded Cost Differential (ECD) to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.

PPL/300, Duvall/2.

The ECD calculation computes the difference between the embedded cost of the hydro resources, the Mid-C and Existing QF contracts, and the embedded costs of other resources on the system. These costs (or credits) are then allocated to states on certain special allocators (DGP for hydro, MC for Mid-Columbia and situs for existing QFs). Because hydro and the Mid-C contracts cost less than other resources, they produce a benefit to Oregon.

The problem with the PacifiCorp proposal is that it uses the DGP and MC factors to allocate the difference in *system incremental costs* (primarily fuel and purchased power expense) to Oregon as if those costs were equivalent to the embedded costs used in the ECD calculation. In effect, the Company proposes to assign Oregon the great majority of the impact of hydro generation variations.

Given that there is currently a drought, it is most likely Oregon would be overpaying in the initial application of the PCAM.

Q. HOW SHOULD THE PCAM ALLOCATION OPERATE IN ORDER TO BE CONSISTENT WITH THE REVISED PROTOCOL?

A. When there is a hydro shortfall, the system response is to increase generation from thermal units and purchase more power from the wholesale market. In contrast, when there is a hydro surplus, the system response is to decrease generation from thermal units and purchase less power from the market. Fuel and purchased power expenses are normally allocated in rate cases under the Revised Protocol on a System basis (using the SE or SG allocators). Thus, under the Revised Protocol, Oregon bears about 29% of these costs. Based on the PacifiCorp PCAM methodology, however, Oregon would likely be assigned more than twice this amount of cost responsibility.

In a rate case, there also would be a subsequent calculation of the ECD adjustment between the states. Fuel and purchased power costs are included in the ECD calculation. If more fuel and purchased power expense is incurred, it would increase the embedded cost of non-hydro resources and increase the value of the credit allocated to Oregon on the DGP and MC factors. There would also be a change in the average cost per megawatt hour ("MWh") of hydro generation because the amount of energy produced by hydro would be changed. These, however, are not substantial effects and therein lies the problem with the PacifiCorp proposal. Rather than actually re-computing the revenue requirement, the Company would make a very crude approximation that consistently assigns far too much of the impact of hydro variations to Oregon.

Exhibit ICNU/104 demonstrates the impact of this problem and shows the PacifiCorp proposal substantially over allocates costs to Oregon for hydro deficits. This analysis is based on the Company's projections for 2005 based on information it filed in UM 1193, the hydro deferral docket. While the cost of the hydro shortfall is not computed in exactly the same manner as would be done for the GRID studies, this analysis is directed toward the question of the allocation of these costs, not their amount. Based on the PacifiCorp allocation methodology, Oregon would bear 59% of the cost of a hypothetical 2005 hydro shortfall using the PCAM methodology. Under the Revised Protocol allocators, ignoring the ECD impact, Oregon would bear less than 29% of these costs. Even with the full recalculation of the ECD, Oregon would bear less than 50% of the hydro shortfall costs shown in ICNU/104. Therefore, the PCAM shifts more costs associated with a hydro shortfall than is appropriate under the Revised Protocol.

Q. DO YOU BELIEVE THAT THE ECD PORTION OF THE CALCULATION SHOULD EVEN BE APPLIED IN A PCAM SETTING?

A. Not unless it is applied to all states at the same time in exactly the same manner. The ECD credit is not an incremental cost to the Company in the same sense as increased purchased power and fuel expenses resulting from a hydro shortfall would be. The reason is that the ECD amounts to an "after the fact" allocation of costs among the states, not an incremental cost of hydro variations to the Company. The ECD calculation is a "zero sum game" between the states, and does not have any impact on shareholders, so long as all states are included in the same way. If the cost of fuel goes up because of poor hydro, the Company has no choice but to pay for more fuel. However, it does not follow that the Company would at the same time incur a cost because its allocation of the ECD among the states had theoretically changed. Indeed, unless the Company has an identical, and simultaneous PCAM in every state, there will be no ECD dollars flowing between the states Therefore, unless all Commissions approve of a completely equivalent PCAM, the Commission should completely ignore the ECD aspect of this analysis.

Further, because the ECD is based on normalized hydro levels, it is a legitimate question as to whether it should even be adjusted in a PCAM setting, if actual hydro conditions differ from normalized ones. Recall, that while PacifiCorp used the Modified Accord Fuel Credit for general rate cases prior to UM 170, it never reflected any changes to the fuel credit in the various deferral cases (e.g., UM 995) it filed during the power crisis.

With or without revising the ECD calculation, the proper allocation of the impact of hydro variations to Oregon is greatly overstated in the proposed PCAM.

Q. CAN YOU TIE THIS INTO YOUR COMMENT THAT THE PCAM IS "NEEDLESSLY COMPLEX."

A. Ultimately, a PCAM (if permitted at all) should only deal with the incremental costs of power cost variations. These are basically fuel and purchased power and should be allocated under the Revised Protocol using the system allocators only. There really is no need for the complications of the additional GRID studies required to decompose the power cost variations into specific causes. If a PCAM were allowed at all, there really is no need for the Commission to deal with revising the ECD component of the calculation, or to use "special allocators" for hydro, Mid-C and QFs. Only if the Company proposes an identical PCAM for each state, should the Commission allow the Company to recompute the ECD credit in response to changes in system hydro conditions.

Q. DOES PACIFICORP HAVE A PCAM IN ANY OTHER STATE?

A. No.

2. <u>Deadband and Sharing Mechanism</u>

Q. DESCRIBE THE SHARING MECHANISM IN THE PCAM PROPOSAL.

A. Mr. Widmer testifies: "When actual adjusted net power costs are within plus or minus $100 million, total Company, the increment would be allocated 70 percent to customers and 30 percent to the Company. When the increments exceed plus or minus $100 million total Company, the increment would be allocated 90 percent to customers and 10 percent to the Company so as to provide catastrophic protection." PPL/200, Widmer/7.

Q. IS THIS A REASONABLE SHARING MECHANISM?

A. No. First, there is no dead band in the PCAM proposal. Second, the proposed sharing bands place too much cost responsibility on customers. Both aspects of this proposal are extremely poor public policy and inconsistent with past Commission practice.

Q. PLEASE EXPLAIN.

A. In UM 1071, a PGE power cost deferral request, the Commission articulated its position regarding the issue of dead bands for "stochastic risks" such as power cost variations. In Order No. 04-108, the Commission stated as follows:

> The magnitude of the financial effect on the utility is also a factor in our consideration under the discretionary stage of the decision process. For a stochastic risk to justify deferred accounting, the

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

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

While the Commission did not articulate a hard and fast standard, it is clear that it considered an impact within a 250 basis point deadband inadequate in UM 995, and that 172 basis points was inadequate in UM 1071. Because the proposed PCAM contains no dead band, it clearly is inconsistent with Commission precedent. PacifiCorp has not justified why the Commission should abandon past practice and adopt a PCAM with no deadband.

The sharing mechanism is also far more generous than adopted in the past by the Commission. In UM 995, the Commission required 50/50 sharing on excess power costs between 250 and 400 basis points, and 75/25 sharing above 400 basis points. <u>Re PacifiCorp</u>, OPUC Docket Nos. UM 995 and UE 121, Order No. 02-469 at 3 (July 18, 2002). In the PGE nine and fifteen month PCAs approved pursuant to the settlement in UE 115, the Commission allowed a 50/50 sharing for power cost variances between \$28 and \$38 million per year.[7/] The 70/30 and 90/10 sharing percentages in the PCAM are far more generous than the Commission has authorized in the past in cases where extreme power cost emergencies existed. Under normal circumstances, the Commission should adopt a sharing mechanism that is less, not more, generous to shareholders. PacifiCorp has not presented any evidence to justify why the Commission should provide no dead band and a less stringent sharing mechanism as a matter of course under routine conditions.

3. Definition of Power Cost and Inclusion of Costs That Are Not Highly Volatile

Q. DOES THE PROPOSED PCAM INCLUDE INAPPROPRIATE COSTS?

A. Yes. Based on Mr. Widmer's testimony[8/] and Exhibit PPL/204, the Company wishes to include a wide variety of costs in the PCAM. This apparently includes all items the Company might classify as "actual net power costs" such as fuel and purchased power costs, transmission costs, long term contract costs, hedges and options. The Company actually provides no specific definition of allowable actual power costs, but instead provides only an example based on 2004 actual data. This definition is far too nebulous for a permanent PCAM and should be rejected. *If* the Commission decides to approve a PCAM, then it should first limit eligible costs to only those expenses that are "volatile," "significant" and "beyond

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7/ Roughly 150 to 200 basis points for PGE based on the figures quoted in Order No. 04-108. Note, however, that the 9 and 15 month PCAs were the result of a stipulation in Docket No. UE 115 that was adopted at the time of the power cost crisis.

8/ "Adjusted actual net power costs are equal to actual net power costs, adjusted to remove prior-period adjustments recorded during the accrual period and to include Commission-adopted adjustments from the most recent rate case." PPL/200, Widmer/8.

the Company's control." This would eliminate solid fuel costs, transmission expenses, and long-term contract costs.

Q. WHY WOULDN'T YOU INCLUDE SOLID FUEL COSTS, TRANSMISSION EXPENSES, AND THE OTHER ITEMS IN A PCAM?

A. PacifiCorp's major power cost expense is for coal, a commodity whose price is fairly stable over time. It is quite normal within the industry to purchase coal under long-term contracts. Thus, these expenses hardly qualify as costs that are volatile and/or beyond the Company's control.

Transmission expenses should not be part of a PCAM recovery mechanism either. These costs are not highly volatile and are not large in relation to total system costs, or even net power costs. There is no need for a PCAM to recover these kinds of costs.

Q. IS THERE ANY NEED TO INCLUDE RECOVERY OF LONG-TERM CONTRACTS AND QF CONTRACTS IN A PCAM?

A. No. These costs are again, contractually specified and not highly volatile. There is no need to include such contracts in the PCAM because they do not create a substantial amount of power cost uncertainty. In some fuel and long-term purchased power contracts escalators are included that increase prices over time. The inclusion of such costs amounts to using a PCAM as a means of obtaining the benefits of a general rate case without actually having to file one. Such contracts would likely result in a PCAM that is not revenue neutral and provide the Company with "automatic" rate increases.

4. Inequitable Treatment of Sales Variations

Q. ARE THERE FACTORS OTHER THAN HYDRO OR PURCHASED POWER THAT CAUSE POWER COST VARIATIONS?

A. Yes. The most serious uncertainty is often the demand for energy. In UE 137, PGE proposed a similar PCAM request. In the course of that proceeding, it was demonstrated that PGE's prior power cost variances were largely created by changes in demand – i.e. load forecast errors. Load forecast errors result in situations where the Company is either long or short, resulting in the need for additional sales or purchases. Depending on market prices, this could create substantial variation in power costs. Because PacifiCorp projects increased sales in the years ahead, it is likely that increased power costs will result, giving rise to additional deferrals under the PCAM.

However, sales increases have counterbalancing effects. If Oregon load grows slowly, while other states loads grow more rapidly, Oregon would absorb some of the costs of growth in the other states. However, in such a situation, Oregon's allocation of fixed costs should also be reduced. This would not occur under the PCAM proposal.

Further, while an increase in loads increases power costs, it also results in an increase in revenues, and thus fixed cost recovery collected in base rates. For this reason, it is unreasonable to compensate PacifiCorp for the increase in power costs, while ignoring the other beneficial effects of increases in demand in terms of fixed cost recovery or reduced allocation of system costs.

5. Exclusion of Gas Resale Revenues

Q. HOW ARE GAS RESALE REVENUES TREATED IN THE PACFICORP PROPOSAL?

A. It does not appear that PacifiCorp intends to fairly address gas resale revenues in its PCAM proposal. Gas resale revenues can be significant, particularly when the Company acquires too much gas and resells it in a rising market. In UE 170, the Company estimated the value of this very adjustment to be $22.3 million dollars. While the Company built this amount into the baseline net power costs, it appears there is no adjustment to reflect actual gas resale revenues in the adjusted actual net power costs. This would have the effect of negating much of the original deduction. This is yet one more defect in the PCAM proposal.

VI. CONCLUSION

Q. COULD YOU SUMMARIZE THIS PORTION OF YOUR TESTIMONY?

A. I have identified a number of practical problems with the PCAM proposal that must be addressed. I urge the Commission to reject the PCAM proposal. There are simply too many problems and defects in the PCAM proposal for the Commission to adopt it. It would be far better to reject it and tell the Company to "go back to the drawing board." However, if the Commission does elect to implement some form of PCAM, significant changes in the Company's proposal and a rulemaking are needed to address the concerns I have identified.

Q. DOES ICNU INTEND TO FILE ADDITIONAL TESTIMONY AFTER THE DECISION IN UE 170?

A. Yes. As allowed by the procedural schedule, ICNU plans to file additional testimony related to the cost of capital, the resolution of the Company's proposed

RVM, and other issues that will be more clear once the Commission issues its decision in UE 170.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ICNU/101

Randall J. Falkenberg Qualifications

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

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

PROFESSIONAL EXPERIENCE

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

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

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

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

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

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

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

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

PAPERS AND PRESENTATIONS

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

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

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

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

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

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley	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 fossil	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling generating units.
3/85 storage	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General &	Georgia Power Co.	Cancellation of nuclear

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Georgia Public Service Commission Staff		plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7- Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86 613	9437/	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524- E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87- 013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/88 gas	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90 study.	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning
12/90	U-9346	MI	Association of	Consumers Power	DSM Policy Issues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Businesses Advocating Tariff Equity (ABATE)		
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.

Expert Testimony Appearances
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Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035- E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996- EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial	Tampa Electric Co.	Polk County Power Plant

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
			Power Users Group		Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition.
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost

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Date	Case	Jurisdict.	Party	Utility	Subject
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT	CCS	PacifiCorp	Certification of Peaking Plant
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UE-032065	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling

ICNU/102

Excerpt of PacifiCorp Presentation
Regarding Heat Rate Initiative

ScottishPower

Leading the World to Better Performance

PACIFICORP

USING EtaPRO TO SUPPORT PACIFICORP'S HEAT RATE INITIATIVE IN A COMPETITIVE ENERGY MARKET

Presented at the

EPRI Heat Rate Conference

January 28, 2003

Why a Heat Rate Initiative Now?

In the past, PacifiCorp benefited from low cost coal………

- Heat Rate was secondary to generation
- Fuel costs were passed through to customers

That all changed…..

- The Energy Crisis Hit
- Coal prices became unstable and increased 400%
- Scottish Power promised improvements

As one of the lowest-cost electricity producers in the United States, PacifiCorp generates about 8,000 megawatts of energy from coal, hydro, gas-fired combustion turbines, geothermal and renewable wind power.

PACIFICORP

Leading the World to Better Performance

PacifiCorp's Heat Rate Initiative

- Implement a comprehensive program to improve various processes associated with plant efficiency & equipment modifications to reduce heat rate 1.0 %
- Key Enablers
  - Install a data historian on each unit
  - Install an On-line Performance Monitoring system on each unit
  - Establish a corporate standard for monitoring and improving unit performance.

PacifiCorp operates 10 thermal electric plants that generate electricity from coal, geothermal or natural gas resources. The company is also part owner of six thermal plants. Together, these plants generate 7,168.8 megawatts of electricity, which account for more than 80 percent of PacifiCorp's generation capabilities.

PACIFICORP

Leading the World to Better Performance

ICNU/103

Issues Arising in Fuel and Purchase Power Review Cases

EXHIBIT ICNU/103
ISSUES ARISING IN FUEL AND PURCHASE POWER REVIEW CASES

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

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

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

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

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

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

Georgia Power Company, Georgia Public Service Commission Docket No. 3741-U. Acquisition planning for a low-sulfur coal plant.[1/] Rate treatment of payment of "front-end costs" for development of failed coal mine.

1/ This issue was also litigated in the Big Rivers cases mentioned above.

ICNU/104

Corrected Calculation of Possible Deferral
PacifiCorp PCAM vs. Revised Protocol

Exhibit ICNU/104
Corrected Calculation of Possible Deferral PacifiCorp PCAM vs. Revised Protocol

				Actual Feb-05	Mar-05	Apr-05	Forecast May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Hydro Generation - Deferral Period														
	West Hydro		2,535,056	211,436	199,756	309,970	270,834	199,371	178,254	175,447	168,838	177,622	260,834	382,694
	East Hydro		359,427	12,664	28,033	48,656	56,710	42,673	36,512	34,607	27,361	21,630	22,309	28,272
	Mid C		1,446,840	165,307	162,993	133,131	148,484	132,420	117,072	116,649	110,199	117,682	114,963	127,940
Total Hydro Generation			4,341,323	389,407	390,782	491,757	476,028	374,464	331,838	326,703	306,398	316,934	398,106	538,906
Hydro Generation - In Rates														
	West Hydro		4,048,731	497,816	467,101	365,064	326,502	305,884	269,933	233,071	239,364	326,967	487,157	529,872
	East Hydro		268,059	32,959	30,926	24,170	21,617	20,252	17,872	15,431	15,848	21,648	32,254	35,082
	Mid C		1,707,342	195,609	158,364	117,822	156,339	169,046	172,589	148,338	134,955	158,699	127,866	167,715
Total Hydro Generation			6,024,132	726,384	656,391	507,056	504,458	495,182	460,394	396,840	390,167	507,314	647,277	732,669
	Mid C	80%		45.87	48.26	50.59	55.87	61.07	71.38	74.75	68.53	62.87	65.34	70.27
	Jim Bridger	10%		13.19	12.52	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40
	Hermiston	10%		26.81	26.78	27.48	27.48	27.48	27.48	27.48	27.48	27.48	27.48	27.48
	Weighted Cost		0.00	40.70	42.54	44.46	48.68	52.84	61.09	63.79	58.81	54.28	56.26	60.20
Change In Hydro	**West Hydro**		(1,513,675)	286,380	267,345	55,094	55,668	106,513	91,679	57,624	70,526	149,345	226,323	147,178
	East Hydro		91,368	20,295	2,893	(24,486)	(35,093)	(22,421)	(18,640)	(19,176)	(11,513)	18	9,945	6,810
	Mid C		(260,502)	30,302	(4,629)	(15,309)	7,855	36,626	55,517	31,689	24,756	41,017	12,903	39,775
	Total		1,682,809	336,977	265,609	15,299	28,430	120,718	128,556	70,137	83,769	190,380	249,171	193,763
Cost - Total Company Basis														
	West Hydro		76,940,064	11,654,520	11,372,322	2,449,479	2,710,141	5,628,573	5,600,853	3,675,720	4,147,775	8,107,044	12,732,932	8,860,704
	East Hydro		(5,101,527)	825,925	123,062	(1,088,648)	(1,708,468)	(1,184,815)	(1,138,755)	(1,223,199)	(677,103)	977	559,506	409,989
	Mid C		14,889,577	1,233,170	(196,908)	(680,638)	382,413	1,935,464	3,391,645	2,021,378	1,455,950	2,226,567	725,923	2,394,614
	Total		86,728,114	13,713,616	11,298,476	680,194	1,384,086	6,379,222	7,853,743	4,473,899	4,926,622	10,334,588	14,018,360	11,665,308
PacifiCorp Calculation of Allocation to Oregon														
Oregon Allocated Amounts	**MSP Factor**													
West Hydro	**DGP**	**55.6575%**	42,822,916	$6,486,615	$6,329,550	$1,363,319	$1,508,397	$3,132,723	$3,117,295	$2,045,814	$2,308,548	$4,512,178	$7,086,832	$4,931,647
East Hydro	**SG**	**28.5551%**	(1,456,746)	$235,844	$35,141	-$310,864	-$487,855	-$338,325	-$325,173	-$349,286	-$193,347	$279	$159,767	$117,073
Mid C	**MC**	**65.8902%**	9,810,772	$812,538	-$129,743	-$448,474	$251,973	$1,275,281	$2,234,761	$1,331,890	$959,328	$1,467,089	$478,312	$1,577,816
		Total	51,176,942	$7,534,997	$6,234,947	$603,981	$1,272,515	$4,069,679	$5,026,884	$3,028,418	$3,074,529	$5,979,546	$7,724,911	$6,626,535
% of Hydro Cost Allocated To Oregon			**59.0%**											
		System Allocation Factor		28.6%	28.6%	28.6%	28.6%	28.6%	28.6%	28.6%	28.6%	28.6%	28.6%	28.6%
		System Cost	14,636,605	$2,155,009	$1,783,195	$172,738	$363,939	$1,163,928	$1,437,689	$866,128	$879,315	$1,710,150	$2,209,325	$1,895,189
		ECD Adjustment		2,599,134	2,599,134	2,599,134	2,599,134	2,599,134	2,599,134	2,599,134	2,599,134	2,599,134	2,599,134	2,599,134
		Total	43,227,081	$4,754,143	$4,382,329	$2,771,873	$2,963,073	$3,763,062	$4,036,823	$3,465,262	$3,478,449	$4,309,284	$4,808,459	$4,494,323
		Oregon %	**49.8%**											

ICNU/105

PacifiCorp’s Response to ICNU Data
Request No. 1.7

UE-173/PacifiCorp
June 9, 2005
ICNU 1st Set Data Request 1.7

ICNU Data Request 1.7

Does the company agree that in PPL/204 Actual Net Power Costs were not adjusted to reflect the SMUD contract? If not, please explain why not.

Response to ICNU Data Request 1.7

The Company should have made the SMUD adjustment, but it was inadvertently overlooked.

ICNU/106

PacifiCorp's Response to ICNU Data Request No. 1.3

UE-173/PacifiCorp
June 9, 2005
ICNU 1st Set Data Request 1.3

ICNU Data Request 1.3

Reference PPL/204. Please explain in detail what is meant by "PCAM GRID Studies" (lines 4, 5 and 6). Please explain how each such GRID study will be created, what will be the source for the input data, and what changes will be made from the base case.

Response to ICNU Data Request 1.3

PCAM GRID studies refers to GRID runs used to identify the net power cost impact of changes in Company owned hydro generation facilities on the west side of the system (Company-owned hydro-west) and Mid Columbia hydro, so the impacts can be allocated to Oregon under the revised protocol.

The starting point for the studies would be the last authorized NPC in rates. The Company would then do a new GRID run with the actual market prices during the deferral period to determine a new base for measuring the impact of hydro changes. The Company would then run another study with actual generation for Company-owned hydro resources-west. The difference between the market price run and the Company owned hydro-west run would be the net power cost impact of actual Company owned hydro-west. The Company would then run another incremental study with actual Mid Columbia generation. The difference between the Company-owned hydro-west study and the Mid Columbia study would be the net power cost impact of actual Mid Columbia hydro generation.