BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1050

In the Matter of the Application of	)
	)
PACIFICORP	)
	)
Requesting to Initiate an Investigation of Multi-Jurisdictional Issues.	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS

OF NORTHWEST UTILITIES

REDACTED VERSION

(Shading indicates confidential material)

July 16, 2004

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, 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"). My qualifications are in Exhibit ICNU/101.

Q. WHAT KIND OF CONSULTING SERVICES ARE 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 energy cost recovery issues.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses PacifiCorp's (or the "Company") proposed "Revised Protocol" and other issues related to jurisdictional allocation, which the Oregon Public Utility Commission ("OPUC" or the "Commission") has been investigating as part of the Multi-State Process ("MSP") in Docket No. UM 1050. For clarity in the remainder of this testimony, I will refer to the original filing Protocol merely as the "Protocol," the May 21, 2004 Revised Protocol as the "First Revised Protocol," and the June 30, 2004 Revised Protocol as the "Second Revised Protocol." In instances where the two latter documents share common attributes or my comments are applicable to either, I may simply refer to them collectively as the "Revised Protocol."

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My major findings and recommendations are as follows:

1. **I recommend that the Commission reject PacifiCorp's June 30, 2004 Second Revised Protocol. The Commission should either develop an allocation method based on the pre-merger Pacific Power and Light Company ("PP&L") system or correct several problems with the Second Revised Protocol. Should the Commission prefer the former approach, it should direct PacifiCorp to file a "Hybrid" based methodology in the Company's next general rate case. In this testimony, I concentrate on the latter option and recommend a series of changes to the document.**

2. **In its order approving the PP&L – Utah Power and Light ("UP&L") merger in 1988 (the "Merger"), the Commission voiced its concern that the combination of the lower cost Pacific system with the higher cost Utah system should not be allowed to harm Oregon ratepayers. Unfortunately, there is evidence that demonstrates that the Commission's concerns have materialized.**

3. **While Oregon originally had lower rates than Utah, in recent years its rates have been higher than Utah's. The trend in rates since the Merger demonstrates that Oregon is now bearing a more than equitable share of system costs. Ironically, this disparity in rates has occurred despite the fact that Oregon's load growth has been much lower than Utah's, resulting in far less pressure on overall system costs. The Revised Protocol proposal offers Oregon no relief from this troubling rate trend.**

4. **Since the time of the Merger, PacifiCorp has assumed the risk of a failure of the MSP. Further, PacifiCorp is now proposing different MSP methodologies in different states. In light of this fact, the Commission should implement a jurisdictional allocation method that it views as reasonable and equitable, irrespective of the positions taken by other states.**

5. **The Revised Protocol does not contain a fully compensatory hydro endowment for Northwest customers and fails to address the issue of cost shifting among the states. I offer proposals to address these defects.**

6. **On June 23, 2004, PacifiCorp entered into a Stipulation regarding the MSP issues with the Utah parties. By virtue of this stipulation, PacifiCorp now has a direct financial interest in minimizing the**

difference between the allocation of revenue requirements under the Second Revised Protocol and the Rolled-In method preferred by Utah. As a result, PacifiCorp cannot be counted on as an "honest broker" in its administration of the Second Revised Protocol document or MSP activities such as the MSP Standing Committee.

7. **If the Commission does adopt the Second Revised Protocol, I recommend several additional adjustments and conditions of acceptance to mitigate some of these concerns. I propose a combination of rate credits and hard rate caps to ensure that Oregon ratepayers obtain some benefits from adoption of the Second Revised Protocol.**

II. MULTI-STATE PROCESS

Q. BRIEFLY EXPLAIN WHAT MSP CONCERNS.

A. MSP concerns the allocation of the costs of resources among the various states and jurisdictions in which PacifiCorp operates. The problem regarding allocation of the costs among these states and jurisdictions originated with the Merger and remains unresolved.

Q. THE MERGER WAS APPROVED BY THE OPUC IN JULY 1988. WHY, AFTER 16 YEARS, IS THE ISSUE OF A JURISDICTIONAL ALLOCATION METHODOLOGY STILL UNRESOLVED?

A. This is a fairly common problem for multi-state utilities. In cases where there is a "system agreement,"[1/] such issues are resolved by the Federal Energy Regulatory Commission ("FERC"). Because PacifiCorp has no system agreement, the FERC is not involved in this process. However, even when the FERC is involved, FERC regulation of such agreements has frequently been a source of bitter controversy. Also, when mergers have occurred, there can be lingering problems

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[1/] A system agreement is a contract that specifies the allocation of costs and resources among operating units in multi-state utilities. Examples include Southern Company, Entergy, and American Electric Power. Because such agreements generally control wholesale transactions, the FERC regulates them.

in resolving such issues when noticeable cost differences existed between the pre-merger companies.

In the case of PacifiCorp, the problem can be traced back to decisions made by PP&L and UP&L at the time of the Merger. It now appears that the applicants were simply too anxious to gain approval of the Merger to take the time necessary to resolve this difficult issue at that time. Rather, the Company offered to convene a jurisdictional allocation committee with all of the involved states only *after* approval of the Merger was obtained. Re PacifiCorp, OPUC Docket No. UF 4000, Order No. 88-767 at 5 (July 15, 1988).

A major concern of regulators in the Northwest was the impact of the higher cost UP&L system on the lower cost PP&L system. For example, in the OPUC order approving the Merger, the Commission was clearly concerned about this potential problem:

> Second, the stipulation provides that pre-merger generation and transmission facilities of Pacific and Utah Power shall remain the responsibility of the Pacific and Utah divisions, respectively. *This will ensure that the higher cost facilities located in Utah will not have a negative impact on Oregon ratepayers. If necessary, the Commission has the authority to require the continued segregation of the Utah Power rate base from the Pacific Power rate base beyond the term of the stipulation. Likewise, the determination of variable power costs by use of stand-alone and merged-operation simulations and the allocation of net merger benefits could be continued beyond the five-year period.*

Id. at 22 (emphasis added).

A comparable passage is found in the Washington Utilities and Transportation Commission ("WUTC") order approving the Merger:

> Staff witness Folsom correctly points out the discrepancy in average system cost between Pacific Power and Utah Power. The

> Commission continues to be concerned about the effects on Pacific's ratepayers of merging with a higher cost system, and believes that any integration of the power supply function for the two companies should be done in a manner consistent with Pacific's least-cost planning process, now getting under way. In the meantime, the Commission views Pacific's current average system costs as the appropriate basis for rates.

Re PacifiCorp, WUTC Docket No. U-87-1338-AT, Second Supplemental Order Approving Merger with Requirements at 14 (July 15, 1988).

Clearly, the commissions in the Northwest voiced the same concerns and discussed similar interim solutions. The references in the OPUC and WUTC orders concerning continued segregation of power costs (or the use of the Pacific system cost) are significant. It demonstrates that the commissions in the Pacific Northwest put the Company on notice that, from the time the Merger was approved until the cost allocation issues were resolved, it was possible that the average power supply cost of the pre-Merger PP&L system would be used as the basis for setting rates.

Consequently, it is well established that the differences in system costs were a concern of the OPUC and WUTC from the very start. However, it seems clear that the applicants were rather unconcerned with this problem. In fact, the applicants represented to various commissions that *shareholders would assume the risk* of any failure to achieve a consensus concerning jurisdictional allocation. For example, the Commission order from the Oregon Merger case contains the following passage:

> Third, Applicants have committed indefinitely that Pacific's customers will not be harmed by the merger and will not subsidize benefits to Utah Power customers. Applicants recognize that if the merger results in higher costs, those costs will be borne by the

> merged company's shareholders. Applicants further agree that shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the various jurisdictions.

OPUC Docket No. UF 4000, Order No. 88-767 at 22.

Similar language is found in the Utah Public Service Commission ("UPSC") order approving the Merger as well:

> Applicants assert that developing detailed allocations prior to the merger is not essential because the Merged Company's shareholders will assume the risk that differing allocation methods employed by the various jurisdictions could result in less than full cost recovery. The Division testified that this risk of dollars "falling through the cracks" exists currently within the present inter-state allocation process, wherein Applicants' shareholders fully assume the risk of less than full cost recovery.
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> * * *
>
> Applicants propose to convene an allocation task force consisting of representatives of the states in which the Merged Company operates and of the FERC within six weeks following the merger's consummation. This task force is to serve as a forum for the Merged Company and each regulatory jurisdiction to analyze and discuss allocation methods. Such a forum may or may not provide an allocation method to be commonly adopted by all jurisdictions, nor would any decision reached by this task force be binding on regulatory commissions. Regardless of the outcome of the task force, we direct Applicants, within six months of the merger's consummation, to file a jurisdictional revenue requirement and a cost-of-service study, including a proposed method to allocate revenues and costs. The Company will maintain sufficient data to permit any reasonable allocation method to be formulated.

<u>Re UP&L Co.</u>, UPSC Docket No. 87-035-27, Order Approving Merger, 97 PUR 4th 106-107 (Sept. 28, 1988). Although the Company now claims that it is "gravely concerned" with this problem, the current controversy surrounding allocation can be traced back to the fact that PacifiCorp apparently was

insufficiently concerned about it when approval of the Merger was sought. Re PacifiCorp, OPUC Docket No. UM 1050, PPL/202, Kelly/12 (May 21, 2004).

Q. NOW THAT SIXTEEN YEARS HAVE PASSED SINCE THE MERGER, HAVE THE COMMISSIONS' CONCERNS MATERIALIZED?

A. Yes. In fact, there is prima facie evidence that the Merger with the higher cost UP&L system has had a detrimental effect on the rates of the customers of the lower cost PP&L system. Exhibit ICNU/102 shows a series of graphs and tables depicting the trend in average rates for PP&L and UP&L customers in Oregon and Utah over the period 1988 to 2002. This data was obtained from the Department of Energy ("DOE") Energy Information Administration ("EIA") Form 861. This is an official document published by EIA based on annual submissions by electric utilities and it represents the most recent data available from EIA. The data spans the period prior to the Merger to the time when the most recent data was available.

The EIA data shows that, at the time of the Merger in 1988, UP&L in Utah had average rates 34% higher (for all customer classes) than PP&L did in Oregon. Utah's residential rates were 56% higher, and Utah's industrial rates were 19% higher than those in Oregon.

From 1988 to 2002, Oregon's average rates for all classes have increased by 17.6%, while Utah's average rates decreased by 20.1%. During this same period, Oregon residential rates increased by 21.1%, while Utah residential rates decreased by 20%. Furthermore, Oregon industrial rates increased by 8.9% compared to an 18.1% decrease for Utah industries.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE UTAH AND OREGON RATES BASED ON THE MOST RECENT DATA?

A. Based on the EIA 2002 data, Oregon now has *higher average rates* (for all classes combined) than Utah, and both industrial and commercial rates in Oregon are higher as well. Although Oregon's residential rates are marginally lower than Utah's, were it not for the beneficial impact of the Bonneville Power Administration ("BPA") residential exchange, Oregon residential rates also would be higher than Utah's. This trend in average rates makes a compelling argument that the concerns voiced by the Commission in 1988 have now been realized. Based on average rates, Oregon would now appear to be the "higher cost" system, while Utah is the "lower cost" system. Clearly, this data strongly suggests that Oregon has lost ground through the many years of compromise and negotiation in the MSP process, while Utah has gained ground.

Q. DESCRIBE THE ADDITIONAL INFORMATION SHOWN ON PAGE 4 OF EXHIBIT ICNU/102.

A. This table shows a comparison of 1989 and 2002 rates for the six current PacifiCorp jurisdictions. The data shows that Oregon currently has higher average rates (for all classes combined and for industrial customers) compared to any state except for California. For residential and commercial average rates, Oregon is in the "middle of the pack." For all but the residential customer class, Utah had *lower* average rates in 2002 than Oregon.

The exhibit also presents a comparison of Oregon's average rates to those of the other five states for 2002. It reveals that Oregon's average rates exceed those of the other five states combined for all customer classes. Oregon's average rates (for all classes combined) are 19% higher than the average of the other states. Oregon's industrial rates are also 19% higher than those of the other states.

In contrast, in 1989, Utah had higher rates than Oregon, and Oregon was close to the median of the six states. Significantly, from 1989 to 2002, Oregon has had the highest rate of increase in average rates[2/] of all states while Utah has had the lowest. Indeed, as noted above, Utah's average rates have *declined* while Oregon's have *increased*.

This data certainly suggests that Oregon has been disadvantaged since the time of the Merger as compared to Utah and other states. Given that Oregon has the highest average rates of any of the major jurisdictions and average rates 19% higher than those of the other five states, a compelling argument can be made that Oregon is already paying more than an equitable share of system costs. Consequently, the Commission should not feel compelled to accept a compromise of the MSP controversy that does not benefit Oregon customers in the form of lower rates. Rather, the Commission should adopt a fair and equitable methodology that protects Oregon's ratepayers from cost shifts. Perhaps other states will gravitate to the Oregon solution over time.[3/]

[2/] Oregon has had the highest rate of increase for all classes combined. Results are very similar for individual classes as well.

[3/] If the Commission does adopt an MSP compromise approach, it should investigate the reasons that Oregon's rates exceed those of other states. If Oregon's rates are found to be more generous than those in other states, the OPUC should adopt ratemaking conventions more consistent with those in other states.

Q. CAN YOU EXPLAIN THE SPECIAL SIGNFICANCE THESE RATE COMPARISONS HAVE TO ICNU MEMBERS THAT ARE PACIFICORP CUSTOMERS?

A. Yes. The data shows that ICNU members are paying higher rates than industrial customers elsewhere on the PacifiCorp system. This hurts their regional and global competitiveness and further depresses their business outlook. Because Oregon is the only major state to utilize the unfavorable Long Run Incremental Cost ("LRIC") allocation methodology, ICNU members are concerned that every time a dollar of additional cost is allocated to Oregon another disproportionate increase in the rates for ICNU members will occur.

Q. RETURN NOW TO PACIFICORP'S ASSUMPTION OF RISK RELATED TO JURISDICTIONAL ALLOCATION. HOW DOES THE SCOTTISHPOWER MERGER IMPACT THIS OBLIGATION OF THE COMPANY?

A. When ScottishPower acquired PacifiCorp, it certainly should have been aware of this potential problem. Proper due diligence should have identified *all* of the risks faced by PacifiCorp that ScottishPower would be assuming. Therefore, the Commission should view ScottishPower as having assumed any potential liability related to the risk of any failure to achieve consensus in jurisdictional allocation.

Q. WHAT MAKES THIS MULTI-STATE PROBLEM SO INTRACTABLE?

A. <u>First</u>, as pointed out in the passage from the UPSC order quoted above, resolution of the problem requires an agreement by all six states. It appears that there has never been a permanent "meeting of the minds" regarding this problem and difficult new issues have emerged over time. Originally, a prime concern of the Northwest was the manner in which to deal with cost differences between the PP&L and UP&L systems, with the major issue being the low-cost hydro resources on the PP&L system. Utah parties generally sought to merge all of the costs of the system (the "Rolled-In Methodology") and eventually obtain a share of the benefits of these resources. Oregon and Washington parties preferred to preserve the benefits of hydro for their customers in the Northwest.

Recently, the Utah division's resource shortfall and the disparity in growth rates among the states have led to the emergence of a new issue, cost shifting. Like the hydro issue, this concern has proven to be beyond resolution. Cost shifting is a potential outcome of a disparity in growth rates among these states. Underlying differences in the states' attitudes towards the desirability of growth may complicate this issue. From 1992 to 2002, Oregon's peak demand growth was only 7% of the system's overall growth, while Utah was responsible for 93% of the increase in system peaks. Re PacifiCorp, OPUC Docket No. UM 1050, PPL/304 at Duvall/1-2 (Sept. 30, 2003). Oregon's energy sales growth was around 7% of the system total, while Utah's energy growth actually exceeded 100% of the system growth.[4/] Based on this analysis, it appears that Oregon has pursued a conservation-oriented, slow growth strategy, while Utah has followed a high growth path. The rate trend analysis described earlier provides evidence that Utah has benefited from its strategy, while Oregon's strategy has been counterproductive. This problem will be exacerbated unless the cost-shifting problem is carefully addressed.

[4/] Some of the other states' loads have actually declined.

Q. HAVE THERE BEEN ATTEMPTS TO SOLVE THE JURISDICTIONAL PROBLEM IN THE PAST?

A. Yes. There have been temporary solutions beginning with the "Accord" method and followed by the "Modified Accord" methodology. However, no final consensus on a permanent solution has yet emerged. In 1998, the UPSC made a unilateral decision to reject the previously adopted "Modified Accord" methodology in favor of its preferred Rolled-In Methodology. This situation lead PacifiCorp to propose a variety of solutions, including the balkanization of the system in the "Strategic Realignment Plan." This would have lead to the diminution of state regulation vis-à-vis FERC regulation. As a result, it was short-lived. After years of negotiation, PacifiCorp has now settled on an approach of putting forth a "compromise" solution endorsed by the Company and certain Utah parties in the hope that some of the other states will adopt it. However, PacifiCorp's proposed solution fails to accomplish a satisfactory compromise.

Q. IN ITS ORIGINAL DIRECT CASE, THE COMPANY PRESENTED ITS "MSP SOLUTION" OR "PROTOCOL" METHODOLOGY. IS THE COMPANY STILL ENDORSING THIS METHOD?

A. No. On or about May 21, 2004, the Company filed its First Revised Protocol proposal in Oregon and Utah. On or about June 30, 2004, PacifiCorp filed yet another proposal (the Second Revised Protocol) in Oregon, Utah, and Wyoming. Ironically, the Company has not yet filed either new proposal in Washington, which is the only state where it has a rate request pending. I believe the reason that the Company is reluctant to modify its Washington case is that the Revised Protocol methodology would produce lower revenue requirements for Washington than the original Protocol method and it could possibly delay the case. This suggests that PacifiCorp is not really committed to the Second Revised Protocol either, because the Company apparently does not view it as important enough to complicate a pending rate action. This belies the notion that the Company is "gravely concerned" with the MSP problem.

Q. COMMENT ON THE JUNE 30, 2004, OR SECOND REVISED PROTOCOL, DOCUMENT.

A. While the Company filed the same Second Revised Protocol document in Oregon, Utah, and Wyoming, it made a material modification to the document in Utah that is not applicable to any other state. The Company has reached a separate agreement with certain Utah parties that modifies the terms of the Second Revised Protocol in a substantial manner. This side agreement is ostensibly specific only to Utah because it moderates the rate impact of the Second Revised Protocol for that state. Thus, PacifiCorp has really created a Utah-specific Second Revised Protocol because it has a fundamentally different effect on Utah compared to other states. Consequently, there is no way in which the Second Revised Protocol in Oregon will ever be comparable to the Utah Second Revised Protocol. Given that PacifiCorp has purposely decided to offer different proposals in different states (notably Utah, Oregon, and Washington), the OPUC should not be inclined to accept any proposal by the Company carte blanche. Furthermore, the Commission should feel free to condition or modify the Second Revised Protocol as it sees fit. Due to PacifiCorp's failure to file consistent proposals in all six states, the Commission should not be concerned that any amendments it makes to the Second Revised Protocol will complicate relations with other states.

Q. WHY IS THE UTAH SIDE AGREEMENT OF CONCERN TO OREGON?

A. Under the terms of this agreement, PacifiCorp has agreed to hard caps on the rate impact of the Second Revised Protocol as compared to Utah's Rolled-In Methodology. This reduces the overall revenue requirement from the Second Revised Protocol in Utah by [redacted] (NPV 2005-2018).

This raises several "red flags" for Oregon parties. First, by agreeing to limit the rate impact of the Second Revised Protocol as compared to the Rolled-In Methodology, PacifiCorp now has a direct financial interest in minimizing the revenue requirement difference between the Rolled-In Methodology and the Second Revised Protocol in Utah. In all likelihood, any cost not allocated to Utah will be allocated to other states. This means that the Company will no longer be in a position to serve as an "honest broker" with respect to any disputes concerning the proper interpretation of the Second Revised Protocol or in its administration. This should be a very serious concern to the Oregon parties because there is much "unfinished business" concerning the analysis of cost shifting and the seasonal allocations that the Second Revised Protocol calls for the MSP Standing Committee to address.

Further, PacifiCorp will be the party responsible for making the rate filings in all the states. The Company will undoubtedly encounter many situations involving data preparation or interpretation in the development of each jurisdiction's allocation factors. In making these decisions, the Company will have a financial interest in minimizing the difference between the results of the

Rolled-In Methodology and the Second Revised Protocol. This is clearly a concern to Oregon and other states.

Q. WHAT OTHER KINDS OF SITUATIONS COULD ARISE THAT ARE OF CONCERN?

A. In the Revised Protocol, there is a seasonal allocation for combustion turbines that is generally less favorable to Utah than to Oregon. However, it does not apply to baseload coal or combined cycle plants. To minimize the difference between the Revised Protocol and the Rolled-In Methodology, the Company may perceive an advantage in selecting the latter types of resources. Assuming these plants are sited in Utah, the UPSC will have the sole authority for granting a Certificate of Convenience and Necessity ("CCN"). This means that Oregon would have little or no opportunity to address a concern that an inappropriate resource selection was made.

Seasonal Contracts (as defined in the Second Revised Protocol) are also allocated on a basis less favorable to Utah than Oregon. However, the Second Revised Protocol defines a Seasonal Contract as any wholesale contract with a duration of five months or less during a year. Re PacifiCorp, OPUC Docket No. UM 1050, PPL/203 (Revised), Kelly/19 (June 30, 2004). By negotiating for an additional month or two of deliveries, such contracts would no longer be designated as a Seasonal Contract and would no longer be allocated on a seasonal basis. Consequently, the Company could easily make arbitrary decisions that could affect the allocation of these costs.

Call options are another example of contracts that the Company could manipulate to avoid the seasonal designation. A typical call option might only be required for the four summer months. However, the Company might easily be able to negotiate possible deliveries for six months knowing that the strike price will never be reached during the additional two months. Similar comments would apply in the case of temperature hedges.

Further, it is quite likely that the designation of a "State Resource" or situs allocation of an above-market special contract will be a highly controversial aspect of the Second Revised Protocol. PacifiCorp will most certainly have an incentive to "game" these designations to its advantage given the Utah rate cap.

Another situation that might arise would be the re-negotiation of a Qualifying Facility ("QF") contract. Currently, Oregon has QF contracts that are above market and even further above full embedded costs. These additional costs are allocated on a situs basis to Oregon under the Second Revised Protocol. Assume that a QF with an above-market contract approaches the Company offering a price concession in exchange for a new contract with a longer term. Under the Second Revised Protocol, this could favor Oregon because new QF contracts that have any above-market costs are allocated on a situs basis.[5/] For an existing contract, however, the entire amount above current embedded cost is allocated on a situs basis. Even if such an arrangement were in the best interests of ratepayers, PacifiCorp may not be inclined to accept such an offer because it

[5/] In fact, the Company can also control the amount of cost allocated on a situs basis by manipulating its market price assumptions.

could increase the disparity between the Rolled-In Methodology and the Revised Protocol result for Utah.[6/]

Finally, it is unclear in the Second Revised Protocol whether hydro hedges would be considered part of the cost of the system hydro resources or not. If so, then the states that are provided the Hydro Endowment would bear their full cost. Again, this is one of the many kinds of issues that will arise over the years ahead.

Q. DOES THE UTAH SIDE AGREEMENT GIVE THE COMPANY AN OPPORTUNITY TO PROPOSE A NEW ALLOCATION METHODOLOGY?

A. Yes. The agreement also offers PacifiCorp (and all the Utah parties) the opportunity to devise a new methodology if PacifiCorp finds that the Second Revised Protocol differs by more than 1% from the Rolled-In Methodology after 2009:

> 4. Threshold for Continued Support of the Revised Protocol.
>   a. If, with respect to the Company's fiscal years 2010 through 2014, the Company's Utah revenue requirement, calculated pursuant to the Revised Protocol, exceeds or is projected by the Company in good faith to exceed 101.00 percent of the amount that would result from using the Rolled-In Allocation Method, the Company may propose a new interjurisdictional cost allocation method. All parties to this Stipulation agree to consider alternative interjurisdictional cost allocation methods in good faith and will use their best reasonable efforts to come to agreement on an amended Revised Protocol within 12 months after the Company proposes a new method.

Re PacifiCorp, UPSC Docket No. 02-035-04, Stipulation at 4 (June 28, 2004). This clause is significant to Oregon for two reasons. First and foremost, in approving the Second Revised Protocol, given the presence of such a side

[6/] In fact, it is an open question whether a renegotiated QF contract would be considered a new contract, or an existing contract in the Second Revised Protocol. PacifiCorp would have an incentive to assume the latter.

agreement, the OPUC would be acknowledging the option of the Company to propose a new method designed to further narrow the gap between the Rolled-In Methodology and the Second Revised Protocol. In effect, the side agreement puts Oregon (and the other states) on notice of the Company's right to propose a new method should the results differ by more than 1% from the Rolled-In Methodology for Utah.

Second, the passage explicitly references the fact that all of the Utah parties are to play a role in this process, apparently without input from other states. In effect, this paragraph sets up a scenario where PacifiCorp and the Utah parties develop a new method by themselves. While the Second Revised Protocol ostensibly requires unanimous approval by other states, it is possible that future Commissions might accede to PacifiCorp's demands for relief from the (self-imposed) limitations of the Second Revised Protocol and the Utah side agreement. Further, it is likely that the Company will still be running the MSP models at that time and preparing all of the analyses relied on by the MSP Standing Committee. The Company would have an incentive to misstate the expected impacts on other states for any of the new PacifiCorp/Utah joint initiatives. As a result, this side agreement removes the important element of trust from future negotiations because of the financial risk that PacifiCorp has assumed as it relates to Utah ratepayers.

Q. DOES THE SECOND REVISED PROTOCOL OFFER OREGON RELIEF FROM THE RATE DISPARITIES DISCUSSED EARLIER?

A. That is unclear, but it appears very unlikely. While the language of the Second Revised Protocol differs substantially from that of the First Revised Protocol, no new MSP studies have been filed by the Company at this time. The implication, therefore, is that aside from the hard rate caps in Utah, the two documents will produce approximately the same revenue requirements. Confidential Exhibit ICNU/103 presents the average rate per kWh for Utah and Oregon based on the two Revised Protocol documents. Confidential Exhibit ICNU/103, Falkenberg/1-2. This analysis is based on the workpapers contained in the Company's May 21, 2004 filing. Under both the First and Second Revised Protocols, Oregon's rates will increase at approximately the same rate as Utah's over the period 2005-2018. Id. Even if everything goes according to plan in the First Revised Protocol, Oregon's pre-Merger status as a "lower cost" state will not be restored. Unfortunately, there is ample reason to expect the future trend in rates will be less attractive for Oregon than projected by the Company. I shall discuss this shortly.

Under the First Revised Protocol, there was a period from 2005 to 2009 when Oregon had a small rate advantage compared to Utah. However, in the Second Revised Protocol (as modified by the Utah side agreement), even this minor advantage is virtually eliminated. Under the Second Revised Protocol, Oregon and Utah will have rate levels that are approximately equal from 2006 to 2009 and again in 2018. However, Utah will have lower rates from 2010 to 2017. Overall, the Second Revised Protocol provides Utah an average rate advantage of [redacted] compared to Oregon over the period 2005 to 2018. For the period 2011 to 2018, Utah's rate advantage is [redacted].

Q. ONE OF THE COMMISSION'S GOALS IN THIS PROCEEDING WAS TO "INSURE THAT OREGON'S SHARE OF PACIFICORP'S COSTS IS EQUITABLE IN RELATION TO OTHER STATES." HAS THIS GOAL BEEN MET?

A. No. In some respects it is impossible to prove this point one way or the other, because to do so would require determination as to what the proper jurisdictional allocation should be in the first place. As a result, the best tool for evaluating this question is the comparison of average rates. As the above discussion shows, Oregon will continue to have higher rates than Utah for most of the years ahead. Oregon's projected rate of increase in rates will also be comparable to that of Utah's in the years ahead. As a result, the rate disparity will not be addressed, and Oregon will continue to pay more than an equitable share of system costs.

Q. MS. KELLY CITES SEVERAL BENEFITS RELATED TO ACHIEVING A MUTUAL AGREEMENT ON THE JURISDICTIONAL ALLOCATION ISSUE. DO YOU AGREE?

A. No. First of all, the Second Revised Protocol is not a mutually agreed upon solution. As pointed out above, the Second Revised Protocol may never be a mutually agreed upon solution because different states have been provided different Protocols. Nonetheless, I believe Ms. Kelly has overstated the advantages of reaching an agreement. She cites the following benefits:

1. Continued six-state integrated planning;
2. Improved ability to implement results of system planning efforts;
3. Financial health allowing continued access to commercial trading markets;
4. Retention of benefits of the integrated system;
5. Improved ability to address policy differences among the states; and

6. Mitigation of the impacts on other jurisdictions stemming from policies of a single state.

Re PacifiCorp, OPUC Docket No. UM 1050, PPL/202, Kelly/11 (May 21, 2004). I do not deny that achieving a true consensus might further *some* of these goals. However, I question the veracity of some of her claimed benefits. With respect to six-state integrated planning, I question whether the Company really practices integrated planning in the first place. The last three capacity additions on the system, Current Creek, Gadsby, and West Valley, were *not* evaluated on the basis of an integrated system. Rather, the studies underlying those resource additions were based on a simplistic market price analysis using a spreadsheet instead of a production cost model that could simulate the integrated system. PacifiCorp's evaluation of these resources completely ignored their impacts on the remainder of the system. Important modeling issues such as market caps and transmission constraints were ignored in PacifiCorp's modeling.

Further, in the recent Current Creek proceeding, the Company essentially justified the need for that plant on the basis of the peak load forecast of a single state (Utah) for a single year (2005).[7/] PacifiCorp contended that transmission limitations made it impossible to import enough capacity into the state to stave off the reliability crisis. In other words, the Company seems to now assume that the transmission interconnections between east and west have reached their final limits. This would suggest that there is no further ability to integrate capacity

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[7/] In effect, the Company threatened that the "lights would go out" in 2005 if Current Creek was not approved on a highly expedited basis. One Utah party called this "Blackout Blackmail."

additions on the system. If all this is true, PacifiCorp's system is no longer amenable to integrated system planning. As discussed above, the side agreement with the Utah parties further compromises PacifiCorp's interest in a true least-cost integrated planning approach.

Q. DO YOU AGREE THAT OBTAINING A JURISDICTIONAL AGREEMENT WILL PRESERVE THE BENEFITS OF INTEGRATION OF THE SYSTEM?

A. No. First of all, the Company has been inconsistent in its characterization of the benefits of integration. In the 2001 Utah general rate case (Docket No. 01-035-01), the Company considered these benefits so inconsequential that it did not even model the interconnections between the eastern and western divisions in its power cost model. When intervenors disputed this in testimony, the Company modeled the interconnections but claimed they produced less than $1 million in annual benefits. Re PacifiCorp, UPSC Docket No. 01-035-01, Report and Order at 21 (Sept. 10, 2001). In this case, however, the Company contends these benefits amount to $200-$300 million ($NPV) over the period 2005 to 2018. OPUC Docket No. UM 1050, PPL/202, Kelly/12. I simply do not believe that both of these contentions can be true. In all likelihood, one or both of these estimates reflects assumptions of convenience for the Company at a particular point in time.

In any case, the benefits of integration (whatever they may be) exist largely independent of the jurisdictional allocation methodology. The Company still has an obligation to ratepayers to minimize costs. Absence of a mutually agreed upon "MSP Solution" does not eliminate that requirement. Even if PacifiCorp simply chose to ignore the obligation to minimize costs to ratepayers, it cannot ignore the obligation to shareholders to minimize costs between rate cases. It can only do so by maximizing the benefits of integration.

Q. DO YOU AGREE THAT MS. KELLY'S REFERENCE TO FINANCIAL HEALTH AND CONTINUED ACCESS TO TRADING MARKETS IS LEGITIMATE?

A. I am very dubious about it. The Company has not demonstrated that the lack of an approved MSP solution, by itself, has resulted in downward pressure on its credit ratings or that potential counterparties are reluctant to trade with PacifiCorp because of this problem.

Q. HAS PACIFICORP CLAIMED THAT THERE EXISTS A "GAP" IN COST RECOVERY OF $45 MILLION PER YEAR DUE TO LACK OF RESOLUTION OF THE JURISDICTIONAL ALLOCATION?

A. PacifiCorp's analysis of this issue is theoretical. See Re PacifiCorp, WUTC Docket No. UE-032065, PacifiCorp Response to ICNU Data Request No. 4.45 (Mar. 25, 2004). This "gap" would exist only if the Company had a full-blown general rate case every year in every jurisdiction, with all states using identical test years and ratemaking conventions. In contrast, PacifiCorp has gone many years between cases in some states. I understand that Idaho, for example, has *never* had a litigated rate case after the Merger.[8/] In addition, the Company almost always uses different test periods with different sales levels for the various states even when filings are all made around the same time. The Company also uses different test year conventions in every state. For example, Oregon is the only state that has allowed a fully projected test year in recent rate proceedings.

[8/] This was the reason given to me by PacifiCorp witness Dave Taylor for the Company being unable to provide the SE and SG factors used in its last Idaho rate case in response to an ICNU data request.

As a result, there is no comparability between filings. Therefore, it is impossible to determine what the "gap" really amounts to in practice. Because the Company can use regulatory lag to its advantage in states where it may be over-earning, any gap that exists is probably smaller than the Company claims.

Further, in the last major Utah, Oregon, and Washington rate cases, the Company reached settlements with the parties. Likewise, during the power crisis, the Company reached settlements with certain parties in Oregon, Utah, and Idaho concerning recovery of excess power costs. As a result, the Company must have been satisfied with the outcomes of those proceedings. The Company certainly could have pressed their claims regarding this issue in one of the many cases that have occurred in recent years.

Although the Company was adversely affected by the power crisis, that problem had little or nothing to do with the jurisdictional problem, and the Company now appears to be recovering from its lingering financial effects. Consequently, there is no established nexus between the recent financial difficulties claimed by PacifiCorp and the MSP problem.

Q. DO YOU BELIEVE IT IS POSSIBLE THAT BY SECURING A MULTI-STATE AGREEMENT, PACIFICORP'S OVERALL COSTS MIGHT DECREASE?

A. In theory, putting this problem behind the Company *might* have a beneficial impact in lowering its cost of capital. However, there is no evidence in this case to support that contention. In addition, the side agreement with the Utah parties makes it fairly clear that the Company has decided that Utah is the "first in line" to receive such benefits.

Q. TURNING TO MS. KELLY'S FINAL POINT, DOES THE SECOND REVISED PROTOCOL REALLY ENHANCE THE PROSPECTS FOR COOPERATION AMONG THE STATES AND IMPROVE THE CHANCES OF ADDRESSING POLICY DIFFERENCES?

A. The Second Revised Protocol offers little to ensure future cooperation among the states. The proposed MSP Standing Committee seems unlikely to be an effective tool for addressing future points of disagreement. After all, there have been various committees and task forces for years, with no MSP resolution. A further complication is that the different Protocols proposed in Oregon and the other states have standing committees that are required to operate with different rules and obligations. Finally, any amendment to the Second Revised Protocol requires approval of all states except Washington and California. Combined, Washington and California make up 10.5% of the PacifiCorp system. This would provide "veto power" to any of the four larger states. In the end, there is little reason to believe that the MSP Standing Committee will have more areas of common agreement than its predecessor committees.

Q. WHAT ARE THE MOST SIGNIFICANT PROBLEMS WITH THE SECOND REVISED PROTOCOL?

A. There are several serious issues that are not resolved in the document:

1. The proposed Hydro Endowment and Mid-C allocation do not provide sufficient benefits to Pacific Division customers. Pacific Division customers are assigned 100% of the costs of the Western System hydro and Mid-C, but they are allocated only a small portion of the benefits produced by these resources. Indeed, the proposed Northwest system "hydro endowment" is really a liability to Oregon that substantially understates the value of the Northwest hydro resources;

2. There is no structural protection vis-à-vis the issue of cost shifting;

3. The MSP Standing Committee is unlikely to be an effective tool for addressing future disagreements; and

4. There is nothing to ensure that even the limited benefits (rate credits) conferred upon Oregon by the Second Revised Protocol will materialize or be sustainable for the long term.

Q. EXPLAIN WHAT YOU MEAN BY THE TERM "HYDRO ENDOWMENT."

A. "Hydro Endowment," as used in this testimony, refers to a preferential allocation of PacifiCorp's owned system hydro resources (as distinguished from the Mid-C hydro resources) to customers in the Northwest. Historically, some form of Hydro Endowment has always been recognized in the prior jurisdictional allocation methods. The "Accord" method used a load decrement approach to recognize the preference given to the customers in the Northwest. Derivative allocation problems inherent in the load decrement approach led to the Modified Accord. That method used a fuel credit methodology to reflect the Northwest hydro preference. Modified Accord was criticized, however, on the basis that the Northwest customers obtained the fuel benefit of hydro, but did not pay for any of the associated capital costs. Representatives of Oregon and Washington apparently never considered Modified Accord to be anything more than a flawed compromise. When Modified Accord was abandoned by Utah, support for this compromise in other states evaporated as well. To my knowledge, some form of Hydro Endowment has always been considered an absolute requirement by the Oregon and Washington parties in the MSP.

Q. DID PACIFICORP ALSO RECOGNIZE THE HYDRO ENDOWMENT CONCEPT IN ITS ORIGINAL PROTOCOL AND THE FIRST AND SECOND REVISED PROTOCOL FILINGS?

A. Yes. However, the Protocol method simply allocated the capital cost of the hydro facilities to the Northwest but did not fairly allocate the hydro benefits. Both of the Revised Protocols allocate the embedded cost of hydro to the Northwest but credit it against the difference between average system cost of thermal resources and the hydro resources.

Q. DISTINGUISH THE HYDRO ENDOWMENT FROM THE MID-C/QF ALLOCATION ALSO CONTAINED IN THE REVISED PROTOCOL DOCUMENTS.

A. In both of the Revised Protocols, PacifiCorp has proposed to use the same embedded cost credit methodology for allocation of certain Mid-C resources coupled with a situs assignment of the QF plants.

Q. HAS PACIFICORP DEVELOPED AN ANALYSIS OF THE BENEFITS OF THESE FEATURES IN THE SECOND REVISED PROTOCOL?

A. No. Therefore, one must assume that, aside from the preferential treatment afforded Utah (discussed above), the Second Revised Protocol has similar revenue requirements impacts as the First Revised Protocol filed on May 21, 2004. Page 1 of Confidential Exhibit ICNU/103 shows PacifiCorp's analysis of the rate impacts for Oregon and Utah during the period 2005 to 2018 for the First Revised Protocol as compared to the Rolled-In and Modified Accord methodologies. Underlying this analysis is a calculation of the year-by-year revenue requirements of the First Revised Protocol and a calculation of the yearly "credits" and costs associated with the Hydro Endowment and the Mid-C/QF allocation.

Based on the analysis performed by PacifiCorp, this First Revised Protocol would have produced a benefit to Oregon of approximately [redacted] compared to the Rolled-In Methodology and approximately [redacted] to the Modified Accord (NPV 2005 to 2018). Confidential Exhibit ICNU/103, Falkenberg/1. Compared to the overall Oregon power costs in excess of [redacted] during the same period, this benefit is less than [redacted]. Given the vagaries of long-term projections, this may amount to little more than "noise."

Q. ARE THE BENEFITS PROJECTED BY PACIFICORP OVERSTATED?

A. Yes, for several reasons. The most obvious problem is that the PacifiCorp study considers the period encompassing Fiscal Years ("FY") 2005 to 2018. However, PacifiCorp has no plans for a rate filing (which might pass on these "benefits" to customers) using a FY 2005 test year. When the Company files a new rate case, it will likely use a FY 2006 or later test year. However, a substantial portion of the benefits assumed for Oregon under the Revised Protocol occur in FY 2005. As a result, it is too late for those assumed benefits to actually materialize for Oregon, absent some immediate adjustment. Once the first year (FY 2005) is removed from the NPV analysis, the benefit compared to the Rolled-In Methodology drops to approximately [redacted], which is a reduction of [redacted]. Confidential Exhibit ICNU/104.[9]

[9] Note that extending the analysis an additional year at the end (i.e. to 2019) would likely further reduce the benefit to Oregon because, in the later years, Revised Protocol costs Oregon more than the Rolled-In or Modified Accord methodology.

Q. WAS IT MISLEADING FOR PACIFICORP TO COMPARE THE FIRST REVISED PROTOCOL TO THE ROLLED-IN METHODOLOGY OR MODIFIED ACCORD?

A. Yes. The Rolled-In Methodology has never been adopted by the Oregon Commission and, in the most recent Oregon rate case (UE 147), a Modified Accord method Plus a Seasonal Allocation of peaking units was accepted by the Commission. While it is true that the "Modified Accord Plus Seasonal" allocation was the result of a settlement, the same is true of all of the Company's most recent rate cases when Modified Accord was used.[10] Because the settlement in Docket No. UE 147 was not a complete "black box settlement," but rather identified the basic components of the agreement, the use of Modified Accord Plus Seasonal Allocation should be considered now as the current Commission-approved methodology. When compared against Modified Accord Plus Seasonal, the First Revised Protocol produces savings of only [redacted], or less than [redacted] for the period 2006-2018. Confidential Exhibit ICNU/104. Consequently, the savings for Oregon portrayed in the MSP studies are misleading because they do not compare the Revised Protocol to the existing status quo.

Q. WHAT IS THE VALUE OF THE HYDRO ENDOWMENT IN THE REVISED PROTOCOL?

A. Unfortunately, the Hydro Endowment is really a "Hydro Liability." The Revised Protocol provides a credit based on the difference between the embedded cost of hydro facilities and PacifiCorp's thermal resources. Essentially, the method gives

[10] To my knowledge, all PacifiCorp Oregon rate cases since 1999 (when the Utah Commission rejected Modified Accord) have been resolved by settlement. Thus, there is no recent situation where the Commission decided the allocation issue outside of a settlement after the disharmony concerning allocations was rekindled.

Oregon credit for the fact that the hydro resources have a lower average cost per MWh ([redacted] in 2005) compared to the non-hydro resources ([redacted], also in 2005).

Arguably, the concept of a Hydro Endowment is a step in the "right direction" from Oregon's point of view. In practice, however, it is a step in the "wrong direction" for Oregon. Based on the PacifiCorp analysis, the Hydro Endowment in the Revised Protocol is worth only [redacted] to Oregon for the period 2005 through 2018. However, as discussed above, PacifiCorp has no plans to file a 2005 rate case that would allow customers to realize the assumed benefit of the hydro endowment in FY 2005 [redacted]. Over the period 2006-2018, the Hydro Endowment is not a benefit, but rather a liability of [redacted]. Without the benefit assumed to exist in 2005, the remaining costs of the Hydro Endowment outweigh the remaining benefits.

Further, the Company plans to make a downward revision in its forecasts of the amount of hydro energy available from the western system resources and Mid-C. In a June 17, 2004 workshop in Oregon, the Company informed ICNU, the OPUC Staff, and the Citizens' Utility Board ("CUB") that it plans to make a reduction in future hydro generation forecasts by about 2.5%.[11/] If this reduction were applied to the MSP studies, the cost of the Hydro Endowment benefit is increased by an additional [redacted]. Confidential Exhibit ICNU/104.

[11/] This was actually the second hydro forecast revision presented by PacifiCorp. In the first revision, the forecast was reduced by more than 7%. Should the first forecast prove more accurate, there will be an even more substantial impact on value of the Hydro Endowment.

This would produce a net detriment due to the Hydro Endowment of [redacted].[12]

Q. DOES THIS IMPLY THE HYDRO RESOURCES ARE MORE COSTLY THAN PACIFICORP'S OTHER EXISTING PLANTS?

A. No. The problem is not that the hydro resources are high cost facilities. Rather, the problem is that the proposed embedded cost differential methodology includes all of the costs of hydro but fails to recognize some of their most important benefits. These include, most notably, load shaping and contribution to eastern control area reserves (also called dynamic overlay). Certainly, if hydro were removed from the system, costs would increase by much more than shown in PacifiCorp's analysis.

Q. IF THERE IS NOT A BENEFICIAL HYDRO ENDOWMENT FOR OREGON, THEN WHAT IS THE SOURCE OF ASSUMED BENEFITS FOR OREGON IN PACIFICORP'S STUDY?

A. The Revised Protocols contain a revised Mid-C/QF allocation and a seasonal allocation that the Company projects will produce benefits for Oregon. Recent allocation methods have not featured a favorable allocation of the Mid-C contracts for the Northwest. Although the Revised Protocol purportedly does so, the favorable allocation is "unofficially" linked to a new situs allocation of QFs. The net benefit of the combined Mid-C/QF allocation is a benefit of [redacted] to Oregon based on PacifiCorp's modeling. The proposed seasonal allocation is responsible for [redacted] in benefits to Oregon.

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[12] Perhaps this explains why the Utah parties were willing to accept this "Hydro Endowment."

Q. HOW CERTAIN IS THIS ASSUMED BENEFIT?

A. The benefits of the Mid-C allocation (and the value of the Hydro Endowment) are far less certain than the costs of the QF allocation. Hydro variability is substantial, and there is substantial uncertainty regarding the outcome of the relicensing process and the Mid-C contract renegotiations. This is a serious problem because there is no assurance that, once hydro relicensing and contract re-negotiation is completed (and the costs largely borne by the Northwest), other states will not seek to modify or even overturn the Hydro Endowment and Mid-C allocations. Although there is some language in the Second Revised Protocol prohibiting PacifiCorp from disturbing these allocations, other states are free to make such proposals. Ultimately, PacifiCorp may simply request relief from this requirement if it proves too inconvenient. Alternatively, the Company may simply devise a new allocation scheme that has the same financial impact as doing away with the Mid-C allocation, but does so under some alternative theory or scheme. Further, given its financial conflict of interest discussed earlier, PacifiCorp may not have the right incentives to negotiate the best possible replacement contracts for the Mid-C resources.

In addition, the Company recently acknowledged that it had overestimated the amount of energy available from the Mid-C Grant County contract in the Company's MSP studies. Re PacifiCorp, OPUC Docket No. UM 1050, PacifiCorp Response to CUB DR No. 19 (June 24, 2004). The impact on Oregon is more substantial than any other state because Oregon is allocated 100% of the Grant County cost and energy under the PacifiCorp proposal. See Re PacifiCorp, OPUC Docket No. UM 1050, PPL/310, Duvall/1 (May 21, 2004). When the corrected Grant County energy is used in the study, there is an additional cost increase for Oregon of [redacted]. This is more than [redacted] of Oregon's benefit derived from the Mid-C/QF allocation scheme. In the end, there are simply too many unknowns regarding the future value of the Mid-C allocation and the Hydro Endowment to count on PacifiCorp's assumed benefits.

Q. THE SITUS ALLOCATION OF QF CONTRACTS IS DETRIMENTAL TO OREGON. IS THERE AS MUCH UNCERTAINTY SURROUNDING THE COST OF ENERGY AVAILABLE FROM THE QF CONTRACTS?

A. No. The QF contracts have been above market for a very long time, and it appears that there is less opportunity for their re-negotiation in the future. In addition, negotiating an improved QF contract may well be contrary to PacifiCorp's financial interests, as discussed above. Consequently, there is substantial uncertainty with respect to the Hydro and Mid-C energy, but relative certainty as to the cost of generation available from the QF contracts. Because the QF allocation to Oregon is an added cost, this means that the detriments of the Revised Protocol are relatively certain, while the Mid-C benefits are quite uncertain. This is a crucial defect in the Second Revised Protocol in that there is nothing to provide assurance that the benefits of the Hydro Endowment and the Mid-C allocation will be permanent in the years ahead.

Q. ARE THERE ASPECTS OF THE MID-C/QF ALLOCATION THAT PRESENT A POTENTIAL RISK TO OREGON IN THE FUTURE?

A. Yes. The combined QF and Mid-C allocations produce a net benefit to Oregon. However, the primary benefit of the QF allocation to the other states ends in 2012 (when Oregon's last major QF contracts terminate). After 2012, the other states will only see a large "payment" to Oregon that is no longer offset by a "credit" from the situs QF allocation. For this reason, it would not be out of the question for the other states to propose terminating the favorable Mid-C allocation at that time. This could set the stage for a repeat of 1998 when Utah rejected the Modified Accord and its large fuel credit for Oregon. In addition, PacifiCorp itself may decide in 2013 that it is now in the Company's best interests to devise a new methodology, as discussed in the passage from the Utah side agreement referenced earlier.

Confidential Exhibit ICNU/104 also presents the Revised Protocol results recomputed assuming termination of the Mid-C/QF allocation in 2013 along with the new hydro forecasts. Once these adjustments are made, the Revised Protocol will cost Oregon [redacted] more than the Modified Accord Plus Seasonal allocation and essentially the same as the Modified Accord method over the period 2006 to 2018. The Revised Protocol will cost Oregon only [redacted] less than the Rolled-In Methodology over the period 2006 to 2018. More significant is the fact that under this scenario, the Hydro Endowment and the Mid-C and QF allocation becomes a net liability to Oregon. The only remaining benefit for Oregon under the Revised Protocol is a small advantage created by the seasonal allocation of combustion turbines. In effect, the "compromise" proposed by the Company amounts to nothing more than a Seasonal Rolled-In method in disguise under these assumptions.

Q. HOW CERTAIN IS THE CONTINUATION OF THE SEASONAL ALLOCATION UNDER THE SECOND REVISED PROTOCOL?

A. The MSP Standing Committee has an immediate assignment to review the seasonal resource criteria and allocation. OPUC Docket No. UM 1050, PPL/203 (Revised), Kelly/13-14. It is likely that Oregon will be on the "defensive" on this issue from the very start.

Q. DO YOU BELIEVE THESE RESULTS SHOWN IN CONFIDENTIAL EXHIBIT ICNU/104 ARE REALLY INDICATIVE OF THE ACTUAL VALUE OF THE SYSTEM HYDRO AND MID-C TO THE PACIFICORP SYSTEM?

A. No. Confidential Exhibit ICNU/105 summarizes a more realistic analysis of the value of the Hydro Endowment for 2005. Valuing hydro based on system embedded cost alone understates the value of the system hydro, as it ignores the substantial value of hydro for load following. I estimate the value of this benefit to be [redacted] at a system level.

Another serious problem with the Revised Protocol is that it gives no credit for the dynamic overlay (also called reserve) benefits of the hydro resources. Based on PacifiCorp's response to OPUC Staff data request No. 61, this value is [redacted] per year. Re PacifiCorp, OPUC Docket No. UM 1050, PacifiCorp's Response to OPUC Staff DR No. 61 (Mar. 18, 2004). Without dynamic overlay, the eastern division would incur this amount of additional cost every year. In total, Confidential Exhibit ICNU/105 shows that considering the dynamic overlay and load following value, the benefits of hydro resources is understated by [redacted] per year (Total Company basis). This would equate to annual additional benefits of [redacted] per year for Oregon.

Q. MR. DUVALL TESTIFIES THAT THE DYNAMIC ALLOCATION PROCESS USED IN THE PROTOCOL AND REVISED PROTOCOLS LIMITS THE IMPACT OF DIFFERENCES IN LOAD GROWTH ACROSS STATES. PLEASE COMMENT.

A. Mr. Duvall testifies that this was one of the concerns expressed in the MSP, and he believes that the Rolled-In Methodology provides an adequate solution. Re PacifiCorp, OPUC Docket No. UM 1050, PPL/309, Duvall/2-6 (May 21, 2004); Re PacifiCorp, OPUC Docket No. UM 1050, PPL/300, Duvall/15-20 (Sept. 30, 2003). He does so based on various studies that indicate close to 100% of the cost of a new resource ends up being assigned to the fastest growing state. OPUC Docket No. UM 1050, PPL/300, Duvall/16; PPL/309, Duvall/4. Thus, he believes that a "cost shift" is not a major concern. See OPUC Docket No. UM 1050, PPL/309, Duvall/4. Based on this testimony, and representations made by the Company elsewhere, it would be safe to conclude that the Company is not "gravely concerned" about this problem.

However, there are some significant problems with Mr. Duvall's analysis of this problem. First, the mechanism used in the Revised Protocol does not provide any *structural* safeguard against cost shifting. In fact, the results cited by Mr. Duvall stem largely from coincidence—i.e., the faster growing state is not allocated the full cost of new resources but it is allocated more of the other system costs (transmission, distribution, overheads, and other generators). OPUC Docket No. UM 1050, PPL/309 at Duvall/3-4. While this result may occur under current load expectations, fuel costs, and overall cost levels, there is nothing to suggest that this result will occur under different conditions. Consequently, the solution is not necessarily "robust" enough to permanently provide the solution as claimed by Mr. Duvall.

Second, while Mr. Duvall contends the cost shifting is small on a percentage basis, the magnitude is substantial compared to PacifiCorp's assumed "benefits" of the Revised Protocol for Oregon. Depending on whether one accepts the Utah CCS assumptions or those of the Oregon Staff, the amount of the costs shifted to Oregon is [redacted] respectively (NPV$ 2006-2018).[13/] Confidential Exhibit ICNU/106, Falkenberg/1-2. This amounts to [redacted] of the benefit of the Revised Protocol compared to the Modified Accord methodology as projected by PacifiCorp. Id.

Third, there is a substantial intergenerational effect that is not apparent in Mr. Duvall's studies. The fixed costs of new utility owned resources are front-loaded. These costs tend to exceed market levels in the early years. In later years, the costs of utility owned resources are typically below market. Therefore, the benefits of ownership (in the form of offset purchased power costs) are higher in later years. Under traditional regulation, ratepayers are generally expected to pay the higher initial costs with the understanding that they will obtain the benefit of below-market power in the future.[14/] Under both Revised Protocols, those benefits will instead inure to the advantage of the faster growing states in the future. As a result, current generations of Oregon ratepayers will experience

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[13/] These studies assume no adverse growth impact in 2005.

[14/] This is the reason that most states place restrictions on the sale of utility property.

higher costs early on, in exchange for benefits that future generations of Oregon ratepayers may not obtain.

Confidential Exhibit ICNU/107 illustrates this phenomenon in the context of the Current Creek project using data from the recent CCN proceeding. Under the Revised Protocol methodology, Oregon will be allocated approximately [redacted] of the cost of Current Creek when it is above market, while Utah will be allocated [redacted]. However, once Current Creek becomes a below market resource, Utah will be allocated [redacted] of the net benefits, while Oregon will be allocated only [redacted]. Clearly, the method used in the Revised Protocols favors the higher growth state at the expense of the slower growing states.

Finally, Mr. Duvall's study does not address projects that have already been built or are under construction. The Gadsby and West Valley combustion turbines are a prime example. There is a substantial difference in the allocation of costs of these projects depending on the methodology selected for jurisdictional allocation. However, Mr. Duvall's study does not shed any light on the question of cost shifting vis-à-vis recently constructed resources. Mr. Duvall's analysis of cost shifting also failed to include all of the resources that are currently being built.

A major drawback with Mr. Duvall's studies is that they use an outdated (January 2003) IRP. Since that plan was issued, PacifiCorp issued a much higher load forecast for the Utah Division. This necessitated the construction of Current Creek and the Lakeside and Bonanza purchases. While the studies Mr. Duvall references assume a system largely in balance, the reality is that load growth in the east has outstripped supply. See Letter from Don Furman to Lee Sparling, Director, OPUC, regarding West Valley Generation Facilities (May 28, 2004).

While the assumed benefits of new resources are based on highly uncertain long-range projections, there are much more immediate and certain costs that would be allocated to Oregon due to new resource additions. Several new resources will be allocated to Oregon on a rolled-in basis in the next few years. These include Gadsby, West Valley, Current Creek, the recently announced $330 million Lakeside project, and a new twenty-year purchase contract with Bonanza.

Mr. Duvall acknowledges that the Hybrid method would largely insulate the western division from such costs. OPUC Docket No. UM 1050, PPL/300, Duvall/16. In as much as the Revised Protocols were put forth as a compromise between the Hybrid approach and the Rolled-In Methodology, it appears that the Revised Protocol really fails to address this issue in a sufficient manner. Consequently, a major defect of the Revised Protocol is that it does not offer a structural remedy for the cost-shifting problem.

Q. SOME MIGHT ARGUE THAT HYDRO ENDOWMENT AND MID-C ALLOCATION DO NOT REFLECT ALL OF THE COSTS OF HYDRO BECAUSE THE COSTS OF "LOST GENERATION" ARE NOT INCLUDED. IT MIGHT BE ARGUED THAT THIS IS A PROBLEM SIMILAR TO COST SHIFTING. DO YOU AGREE?

A. No. Lost generation has been defined as the reduction in energy available from the PacifiCorp system hydro and Mid-C resources expected in the years ahead. These reductions are primarily due to expected relicensing, renegotiation of Mid-C contracts, and capacity downgrades. This was an argument made primarily by Utah parties in the MSP in an attempt to suggest there is an equivalence between load growth disparities resulting in cost-shifting and the decline in hydro energy expected from Mid-C and the Company's own resources.

It was estimated by the Company that these reductions in available hydro energy will result in an increase in system costs of [redacted] (NPV$) from 2006 to 2018.[15/] Re PacifiCorp, OPUC Docket No. UM 1050, PacifiCorp Response to Staff DR No. 75 (June 2, 2004). However, much of these costs are already assigned to the western states because the value of the Hydro Endowment and Mid-C allocations decline as load declines. Further, as pointed out earlier, the Hydro Endowment is a liability over the period 2006 to 2018 rather than a benefit. PacifiCorp's system hydro is responsible for more than half of the cost of lost generation. Thus, it makes little sense to allocate to Oregon additional costs of the Hydro Endowment when the endowment already is a cost rather than a benefit. Nonetheless, some parties continue to contend that the states receiving the hydro preferences are not bearing all of the costs of lost generation under the Second Revised Protocol.

This is a classic "have your cake and eat it too" argument. The appearance of the cost of lost generation not absorbed by western states only occurs because hydro is not valued at market in the calculation of the hydro preference credits (the Hydro Endowment and Mid-C allocation). The hydro preferences have a low value because they are based on the comparison of embedded costs of hydro to the embedded cost of other system resources. If the

[15/] Lost generation is measured against the 2005 base, so there is no lost generation in 2005.

value of hydro were based on incremental cost (or market value), then the hydro preferences would be much larger. If the hydro preferences were based on market value, then the western states would automatically be allocated 100% of the cost of lost generation as the amount of hydro generation declined. So it is only because the value of the hydro preferences is far below market value that there appears to be a cost of lost generation that is not assigned to the west. For example, if the Hybrid method were used, the west would automatically be assigned 100% of the market value of hydro and would likewise be charged 100% of the cost of lost generation. However, this solution was not acceptable to the Utah parties. Having turned down this offer, I am puzzled as to why they continued to make the "lost generation" argument.

Further, there is no equivalence between cost shifting due to load growth and lost generation. Cost shifting occurs when the faster growing state is allocated an ever-increasing share of the lower cost embedded resources, and the higher incremental cost of load growth is allocated on a Rolled-In basis. Under the Revised Protocol, western states are allocated 100% of the incremental cost of relicensing and new investments required for hydro. Those states do not, however, escape from the allocation of the incremental cost of new resources on the system or from the cost of lost generation. In this case, Oregon bears the incremental cost of hydro but does not escape the incremental cost of new load. Consequently, I believe the lost generation argument can be dismissed.

Q. WOULD THE COMMISSION BE ABLE TO MAKE A DISALLOWANCE OF NEW CAPACITY ON THE BASIS OF A COST SHIFTING ARGUMENT UNDER THE REVISED PROTOCOL?

A. Within the terms of the Revised Protocol, the Commission's recourse would be an appeal to the MSP Standing Committee, which would continue to study the matter. On this point, the Revised Protocols simply offer more studies but no solution. Further, assuming the MSP Standing Committee rejects Oregon's arguments on this point, there appears to be no recourse within the boundaries of the Revised Protocol. The last four major resources added to the system have been built in Utah, and the Utah Commission is responsible for granting a CCN. Because of this, it appears that the Revised Protocol provides Oregon little or no say in approving new capacity additions for which it is expected to charge customers.

III. MSP SOLUTION ALTERNATIVES AND RECOMMENDATIONS

Q. GIVEN THE DEFECTS IN THE REVISED PROTOCOL, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. Based on the language contained in the OPUC Merger approval order referenced earlier, the starting point for the Commission is to go back to using the costs of the pre-Merger PP&L system. The Commission could determine the amount of the pre-Merger PP&L resources needed to serve Oregon and then develop a methodology to share the benefits of system integration equitably among the states. The "Hybrid" proposal is one attempt to develop such a methodology. However, as Mr. Duvall points out, the Hybrid method is not fully developed at the present time. Thus, the record regarding the Hybrid proposal is not sufficiently developed to adopt that proposal in this case. Because this is not a rate proceeding, there is no need to do so at this time anyway. As a result, if the Commission desires to pursue the Hybrid option, I recommend that it require PacifiCorp to file a hybrid allocation methodology in the Company's next general rate case.

If the Commission desires to adopt the Revised Protocol as the framework for jurisdictional allocation, it must make certain adjustments to the document and place certain conditions on its approval.

Q. ASSUMING THE COMMISSION WANTS TO ADDRESS THE SHORTCOMINGS IN THE SECOND REVISED PROTOCOL RATHER THAN DEVELOPING A NEW METHOD, WHAT IS YOUR RECOMMENDATION?

A. At a minimum, the Commission must address the most significant drawbacks to the Revised Protocol. The most fundamental problem is that the Hydro Endowment requires the Pacific Division states to pay the full capital cost of the system hydro resources but provides that they receive only a small share of the benefits. Based on my prior analysis, the projected benefits do not outweigh the costs. In addition, the problem of cost shifting needs to be addressed in a structural manner. Further, the proposed MSP Standing Committee may not prove to be useful without some adjustments. Finally, the Commission should place additional conditions on its approval if it adopts the Second Revised Protocol. Unless these problems are addressed, the Revised Protocol has little, if any, practical value to Oregon.

Q. SECTION XIII.D OF THE SECOND REVISED PROTOCOL REQUIRES UNANIMOUS RATIFICATION FROM THE COMMISSIONS IN UTAH, OREGON, IDAHO, AND WYOMING. IF THE OPUC IMPOSES MATERIAL CONDITIONS ON ACCEPTANCE OF THE SECOND REVISED PROTOCOL OR APPROVES IT ONLY WITH CERTAIN MODIFICATIONS, DOES THAT MEAN THAT OTHER STATES MAY NOT ACCEPT IT?

A. Perhaps, but that fact by itself should not be relevant to the OPUC's decision process. I must point out that this restrictive language was inserted into the Second Revised Protocol but was not included in the First Revised Protocol. This is troubling because it creates an appearance that the Company and/or the Utah parties are making a "take it or leave it offer" to Oregon with no room for compromise.

Further, the Company should not take approval of Wyoming and Idaho for granted. If only one of those states fails to approve the Second Revised Protocol, then it really matters little that Oregon does not grant approval. In any case, the OPUC's decision process should be based solely on considerations of the best interests of the ratepayers in Oregon and not based on arbitrary requirements imposed upon it. Given that the Company is proposing a different Protocol for Washington than other states, and that it is excusing Utah from some of the costs of the Second Revised Protocol, Oregon should not be concerned that it must fall in line with this new requirement.

Q. WHAT THEN IS YOUR RECOMMENDATION REGARDING THE HYDRO ISSUE?

A. Pacific Division ratepayers should not be required to pay 100% of the cost of hydro while obtaining only a portion of hydro benefits. To address this problem, I recommend imputing additional benefits to the embedded cost differential method to recognize the value of load following and dynamic overlay. Fortunately, it is rather easy to compute these quantities for rate case purposes using PacifiCorp's GRID model or other information available in discovery. These quantities were already shown in Confidential Exhibit ICNU/105.

Q. HOW DID YOU COMPUTE THE VALUE OF LOAD FOLLOWING?

A. I have computed the load following value by taking the hydro revenue[16/] derived from the Northwest system hydro and deducting from it the revenues from the same amount of energy assuming a totally flat dispatch profile.[17/] This difference amounts to approximately [redacted]. This benefit should be credited against Oregon revenue requirements using the same allocation factor as is used to allocate the embedded cost of hydro resources.

Q. YOUR PROPOSED METHODOLOGY COMPUTES THE VALUE OF LOAD FOLLOWING BASED ON INCREMENTAL COSTS BUT THE REVISED PROTOCOL ALLOCATES EMBEDDED COSTS. DOES THIS CONCERN YOU?

A. I believe this proposal is conservative. Most of the load following capability on the system is gas-fired and is fairly new. Gas plants have higher energy costs and newer plants typically have higher capital costs than older ones. As a result, it seems likely that an allocation of embedded costs reflecting the load following benefit would show a greater value than this estimate based on short-run energy

16/ The hydro and thermal revenues produced by GRID price the hourly output of each unit at the short-run market price. This is the value considered in the dispatch of units and utilities try to maximize the difference between the market revenue and variable cost on an hourly basis.

17/ I performed this analysis based on the GRID study prepared by the Company in the current Washington rate case because it is the most recent study used in a full blown rate filing.

costs.[18/] However, I am open to persuasion if the Company can demonstrate that this benefit has been overstated. Whatever the actual level of this benefit, it should be reflected.

Q. WHAT IS THE VALUE OF THE DYNAMIC OVERLAY, OR RESERVE BENEFIT?

A. Based on PacifiCorp's response to OPUC data request OPUC No. 61, the annual value is [redacted]. OPUC Docket No. UM 1050, PacifiCorp's Response to OPUC Staff DR No. 61. This amount should also be allocated to Pacific Division states in proportion to the hydro cost. See Confidential Exhibit ICNU/105.

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THE ISSUE OF COST SHIFTING?

A. The Revised Protocol does not really address the cost shifting issue. It merely assigns the MSP Standing Committee to conduct further analysis and to develop possible remedies if a "material problem" is found to exist. The problem is that there is no definition of "materiality" and it seems likely that no progress will ever be made on this issue. Up to this point, the parties have not agreed that there is a material problem. Instead of continuing the cycle of "analysis paralysis," the Commission should insist upon the flexibility to fashion its own growth remedy. To this end, I recommend that the Commission price all new capacity resources at market value, based on the GRID thermal revenue output. This prices the resource at its short-run market price and effectively makes new projects revenue

[18/] This problem is complicated by the fact that the presence of the hydro resources eliminated much of the need for thermal load following units. Thus, there may not be existing resources that serve this function on a consistent basis.

neutral to Oregon ratepayers. In the long run, PacifiCorp will recover its cost in new resources, assuming that they are economical capacity additions.

Q. IS THIS PROPOSAL CONSISTENT WITH OAR § 860-038-0080(1)(b)?

A. Yes. The requirements of OAR § 860-038-0080(1)(b) are as follows:

> Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company.

My proposal meets the requirements of OAR § 860-038-0080(1)(b). While the Revised Protocol does not specify exactly how the revenue requirements of new generators are to be recovered, all of the underlying MSP studies assumed rate treatment based on cost rather than market. Consequently, I think it is safe to assume that PacifiCorp will interpret the Revised Protocol based on a cost rather than market standard.

Q. WOULD ADOPTION OF THIS PROPOSAL DEPEND ON CONTINUED APPLICATION OF OAR § 860-038-0080(1)(b) IN ITS PRESENT FORM?

A. No. I believe the Commission could adopt this kind of treatment for specific plants if it were concerned that they would result in a shifting of costs to Oregon, whether or not this rule continues to apply in a blanket manner to all plants.

Q. HOW DOES THIS METHOD ADDRESS COST SHIFTING?

A. This method renders the new resources revenue neutral to Oregon. This eliminates the high cost in early years of operation that may not be repaid by lower costs later on. PacifiCorp is compensated over the life of these projects by keeping the higher revenues in later years. In the case of West Valley, the term of the lease (15 years) makes it probable that the Company will not collect full market value if the lease extends for the full 15 years.[19] However, the Company should have recognized that this was a problem with the lease at signing.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE MSP STANDING COMMITTEE?

A. Oregon must decide if it is really worthwhile to participate in this process. Having established its own jurisdictional allocation methodology, Oregon should not be inclined to enter into a process of perpetual negotiation.[20] Perhaps other states will gravitate to the Oregon solution.

A serious flaw in the original Protocol and First Revised Protocol was language that requires that each state appoint a Commissioner to the MSP Standing Committee. Washington still follows the original Protocol and, therefore, may send only a Commissioner to the MSP Standing Committee meetings. PacifiCorp's Second Revised Protocol, however, provides that a Commissioner or a delegate be sent. Under these circumstances, there will be different rules for participation in the MSP Standing Committee in different states.

To complicate matters further, the Revised Protocol charges the MSP Standing Committee to study certain issues that are not considered in the original Protocol that still is being used in Washington. As a result, the MSP Standing Committee will have different rules and different expectations for different

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[19] The Company recently gave notice of its intent to terminate the West Valley lease in May 2005. For this reason, this may not be a permanent problem.

[20] It is instructive that at the recent meetings in Boise, the Utah contingent withdrew from negotiations with parties other than PacifiCorp. Since then, the Utah parties reached a favorable settlement with the Company. The implications of this lesson should not be lost on Oregon.

members if Utah, Oregon, Idaho, Wyoming, and Washington all decide to participate. This will create confusion at best and disharmony at worst.

Q. COULD THIS PROBLEM BE CURED BY CONFORMING THE LANGUAGE CONCERNING THE STANDING COMMITTEE IN THE WASHINGTON PROTOCOL AND THE OREGON AND UTAH REVISED PROTOCOLS?

A. No. First, of all, the OPUC has no say in PacifiCorp's relationship with Washington. Second, in Washington, the Company has already indicated it is not willing to accept any aspect of the Revised Protocol unless all of it was accepted. This would seem to rule out adopting part of the Revised Protocol language for Washington state. Even if that problem were resolved, a serious flaw in the Second Revised Protocol is language that requires either a Commissioner or delegate be appointed by each state. If a state does not send a Commissioner, it may lack "clout" compared to other states that do.[21/] However, if a state is represented by a Commissioner, then that could compromise the Commissioner's ability to be an objective judge of new initiatives that emerge from the MSP Standing Committee.

Finally, different states have different ethics rules. It is possible that some states may have ex parte rules that prohibit certain kinds of meetings between Commissioners and utility Company executives. As a result, not all states may be able to send a Commissioner. Given all of this, it is my view that no state should send a Commissioner to the MSP Standing Committee meetings.

[21/] Conversely, if Utah were the only state that sends a delegate instead of a commissioner, it might signal that Utah is simply not committed to making any substantive change to the Revised Protocol via the Standing Committee.

As a result, I recommend Oregon not participate in the MSP Standing Committee unless all states agree to be represented by a Staff level person or other delegate. Further, participation in any MSP Standing Committee meetings should not be limited to parties that supported the Revised Protocol.

Q. ARE THERE ANY OTHER RECOMMENDATIONS YOU HAVE CONCERNING IMPROVEMENTS TO THE REVISED PROTOCOL?

A. PacifiCorp has guaranteed the Utah parties that the level of rate impact on that state will not exceed the amount resulting from the Rolled-In Methodology by more than a specified percentage amount. Oregon should likewise insist upon comparable guarantees of savings if the Second Revised Protocol is adopted. In addition, Oregon should take immediate steps to ensure the assumed savings for FY 2005 actually inure to the benefit of ratepayers.

Q. HOW DO YOU PROPOSE TO ACCOMPLISH THIS?

A. PacifiCorp should be required to implement an immediate rate credit to distribute the projected FY 2005 savings over the remaining months in the fiscal year. For the period 2006 to 2010, this rate credit would be adjusted to equal the Second Revised Protocol savings (relative to Modified Accord Plus Seasonal) now projected by the Company. See Confidential Exhibit ICNU/108. These figures are based on the Company's own calculations of the projected benefits to Oregon of the Second Revised Protocol and should be used as the rate credits.

When the Company makes a general rate filing, it would be prohibited from charging customers more than the projected difference between the Modified Accord Plus Seasonal and Second Revised Protocol result (taking into account the automatic rate credits which would occur irrespective of whether the

Company files a rate case or not). In other words, if the Second Revised Protocol does not save Oregon as much as projected by the Company, PacifiCorp cannot charge ratepayers the additional costs.

From 2010 to 2018, the Company would suspend the rate credits. PacifiCorp would be prohibited, however, from charging Oregon customers more under the Second Revised Protocol than they would be charged under the Modified Accord Plus Seasonal Allocation plus the current projected difference between the Second Revised Protocol and the Modified Accord Plus Seasonal Allocation method.

Q. IS THIS PROPOSAL FAIR TO PACIFICORP?

A. Yes. In some respects it is like Utah's agreement with the Company. However, unlike the Utah side agreement, it will not reduce the projected revenues from the Second Revised Protocol to PacifiCorp. Rather, it will simply ensure that adoption of the agreement does not cost Oregon more than is now expected. It will also counterbalance some (but not all) of the previously discussed incentives that PacifiCorp may have to favor Utah in cases in which the Company must decide between the two states.

Q. ARE THERE ANY OTHER CONDITIONS THE OPUC SHOULD PLACE UPON ITS APPROVAL OF THE REVISED PROTOCOL?

A. Yes. It is likely that the Company will provide incentives to other states as it seeks approval of the Revised Protocol. Oregon should insist upon a "Most Favored Nations" clause to ensure it receives comparable benefits and does not end up being assigned the costs of such arrangements. The Commission should also insist that if ScottishPower sells PacifiCorp, the Second Revised Protocol may be revisited at that time.

In addition, the Commission should take steps to make it clear to the other states what its expectations are regarding the Revised Protocol, particularly with respect to the Mid-C/QF allocation. The Commission should condition its approval of the Revised Protocol on an acknowledgement by the UPSC in its order approving the Revised Protocol that the UPSC respects the Mid-C/QF allocation methodology and will not disturb it in the future. This is an important step that should be taken to insure the sustainability of the Second Revised Protocol if it is adopted by the OPUC. Without a solid and durable assurance from the Company and the other states that the hydro preferences will not be challenged in the future, Oregon should not adopt the Second Revised Protocol.

Q. WHY IS THIS SO IMPORTANT?

A. As demonstrated earlier, without a perpetuation of the Mid-C/QF allocation the Second Revised Protocol is little more than the Rolled-In Methodology. In the past, a major problem has been that the different states had different goals and expectations in the MSP process. Unless Oregon is sure that Utah recognizes the vital role the Mid-C/QF allocation plays in this process, it cannot be sure that the approach will not be upset at a later time.

Further, the Commission should also put PacifiCorp on notice that it will not approve the Second Revised Protocol unless the Company absorbs the risk of other states subsequently seeking to change the agreement to the detriment of Oregon.

Q. DO YOU HAVE ANY SPECIFIC PROPOSALS TO FIX THE SECOND REVISED PROTOCOL?

A. Yes, Confidential Exhibit ICNU/109 contains a listing of conditions that I recommend that the OPUC adopt if it is inclined to approve the Second Revised Protocol.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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

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 Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
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.
10/88 gas	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of sales and revenues.

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

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Date	Case	Jurisdict.	Party	Utility	Subject
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.

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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 Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.

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Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
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
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
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
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor

**Expert Testimony Appearances
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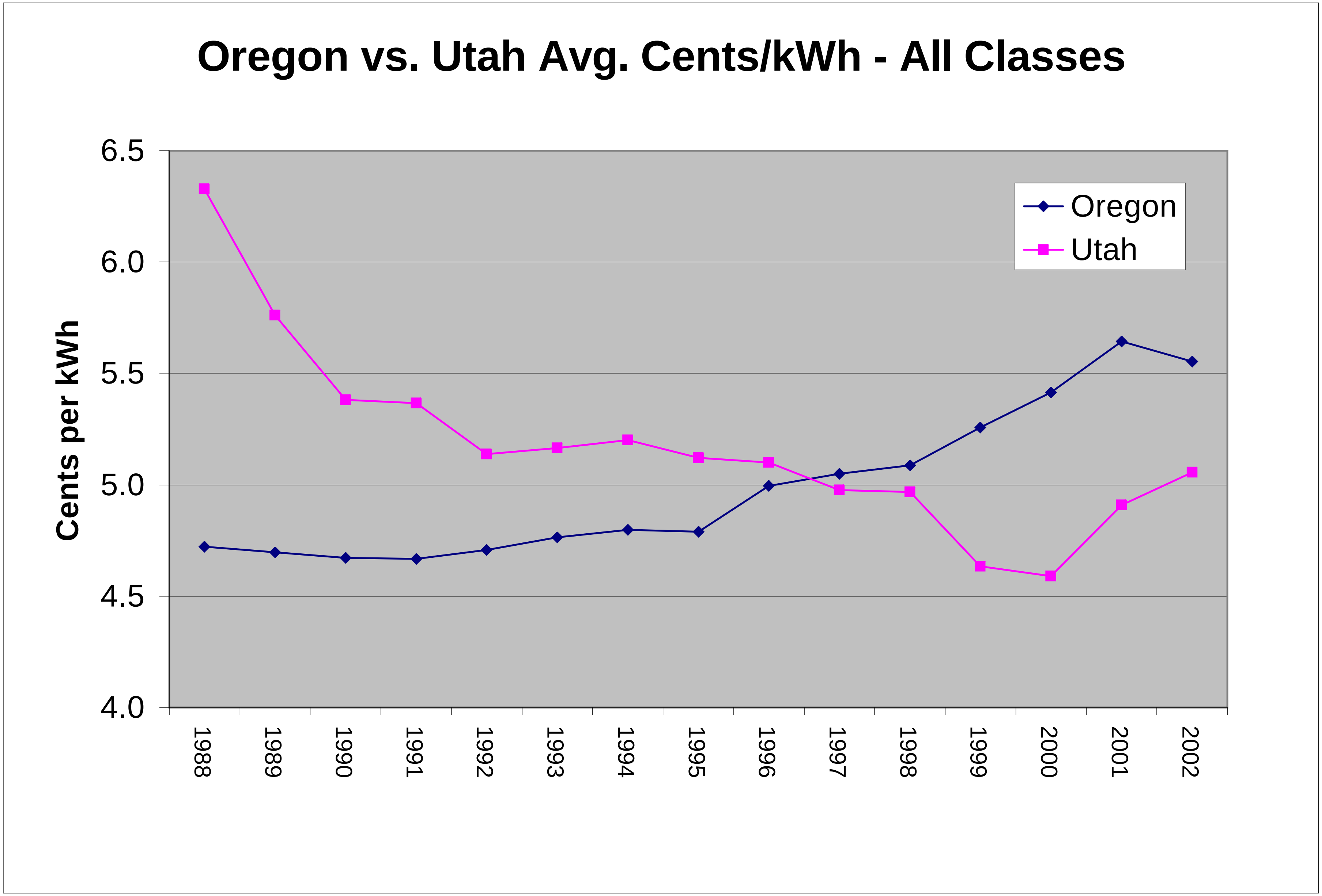
Date	Case	Jurisdict.	Party	Utility	Subject
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail 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

Exhibit ICNU/102
Pre and Post Merger Trend in Rates
Average Revenue per kWh - Oregon and Utah 1988-2002
Source: DOE Energy Information Administration Form 861*

	========Oregon Customer Avg. Cents/kWh=======				=========Utah Customer Avg. Cents/kWh=========			
	Residential	Commercial	Industrial	All Customers	Residential	Commercial	Industrial	All Customers
1988	5.29	5.09	3.78	4.72	8.26	7.32	4.50	6.33
1989	5.24	5.18	3.74	4.70	7.79	6.92	3.96	5.76
1990	5.21	5.09	3.74	4.67	7.38	6.27	3.72	5.38
1991	5.16	5.08	3.76	4.67	7.34	6.08	3.79	5.37
1992	5.20	5.07	3.85	4.71	7.09	5.89	3.63	5.14
1993	5.28	5.07	3.89	4.76	7.00	5.83	3.69	5.16
1994	5.50	5.02	3.87	4.80	6.99	5.79	3.76	5.20
1995	5.53	4.94	3.85	4.79	7.00	5.80	3.65	5.12
1996	5.76	5.18	3.91	5.00	7.00	5.79	3.57	5.10
1997	5.97	5.25	3.83	5.05	6.93	5.60	3.40	4.98
1998	6.15	5.33	3.74	5.09	6.87	5.59	3.37	4.97
1999	6.23	5.39	3.94	5.26	6.18	5.08	3.27	4.63
2000	6.41	5.43	4.20	5.42	6.19	4.97	3.25	4.59
2001	6.52	5.51	4.66	5.64	6.60	5.25	3.36	4.91
2002	6.40	5.67	4.11	5.55	6.60	5.21	3.69	5.06
1988-2002 % Change	21.1%	11.5%	8.9%	17.6%	-20.0%	-28.8%	-18.1%	-20.1%

* Annual Data Supplied to EIA by PacifiCorp, Utah Power & Light and Pacific Power & Light



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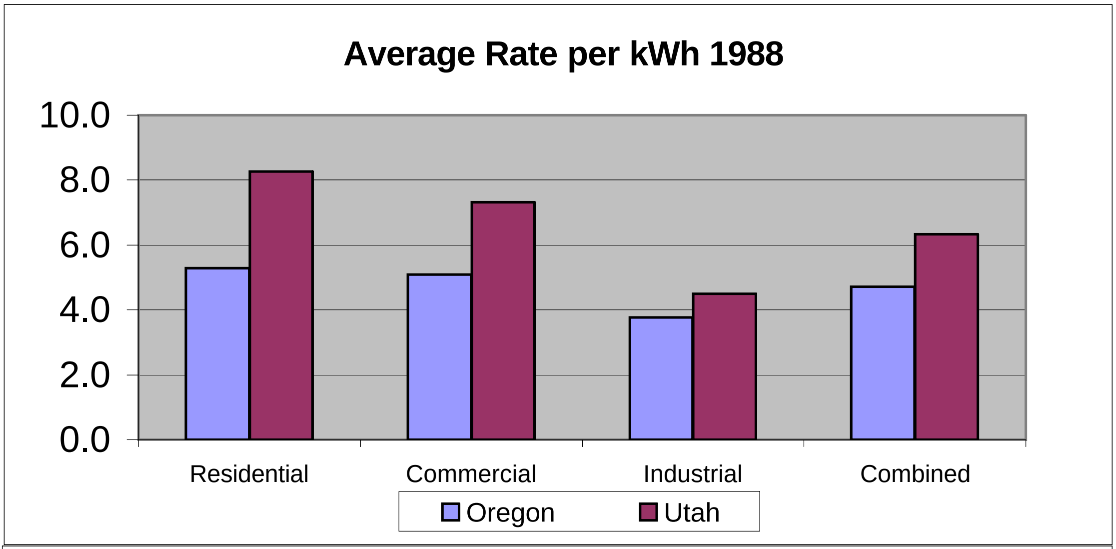
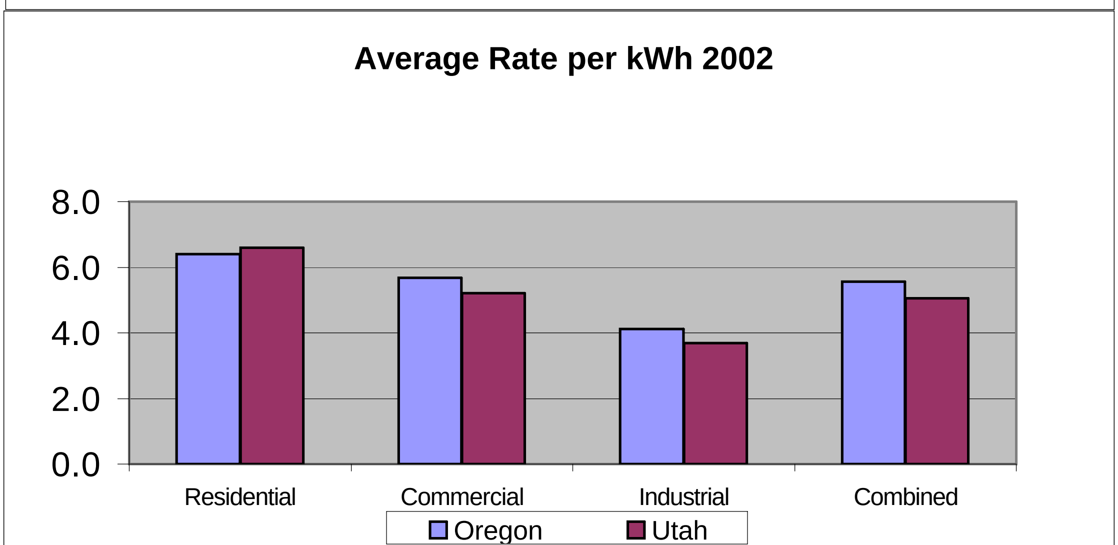

Average Rate per kWh 1988
10.0
8.0
6.0
4.0
2.0
0.0
Residential
Commercial
Industrial
Combined
Oregon
Utah


Average Rate per kWh 2002
8.0
6.0
4.0
2.0
0.0
Residential
Commercial
Industrial
Combined
Oregon
Utah

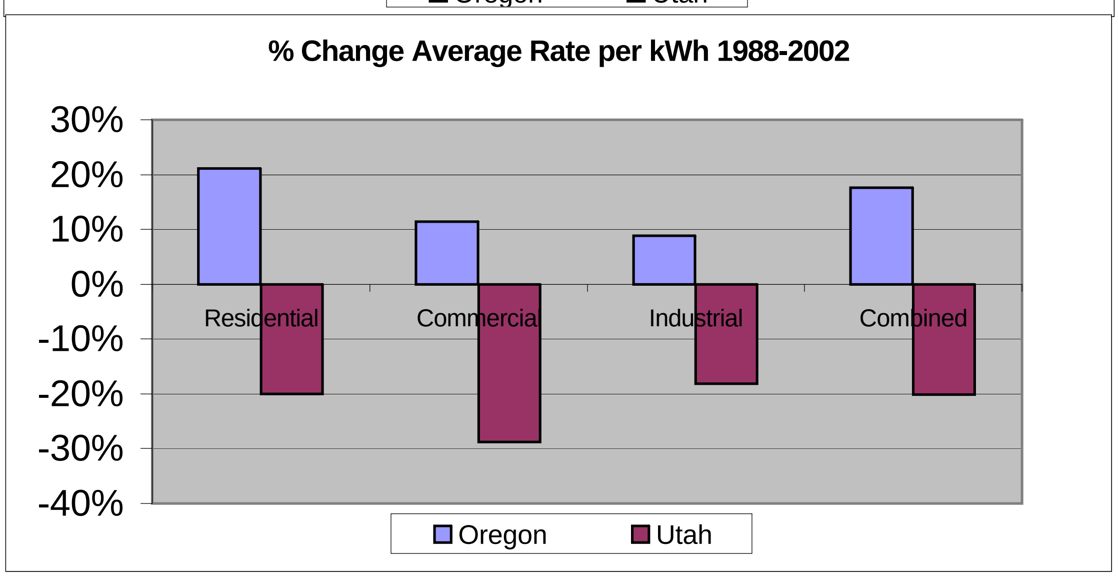

% Change Average Rate per kWh 1988-2002
30%
20%
10%
0%
-10%
-20%
-30%
-40%
Residential
Commercial
Industrial
Combined
Oregon
Utah

Exhibit ICNU/102 **Page 4**

1989 and 2002 Average Rates by Class of Service

2002	Res	Comm	Ind.	All
OR	6.40	5.67	4.11	5.55
CA	7.46	8.08	5.23	7.21
ID	3.89	5.81	2.66	3.24
UT	6.60	5.21	3.69	5.06
WY	6.54	5.25	3.34	4.04
WA	4.46	4.99	4.00	4.50
Non-OR	6.08	5.29	3.45	4.65
OR/Othes	105%	107%	119%	119%
OR Rank*	4	3	2	2
UT Rank	2	5	4	3
1989				
OR	5.24	5.18	3.74	4.70
CA	7.20	9.06	5.57	7.30
ID	5.55	7.54	2.68	3.65
UT	7.79	6.92	3.96	5.76
WY	5.85	4.96	3.31	3.76
WA	4.54	4.77	3.61	4.35
OR Rank	5	4	3	3
UT Rank	1	3	2	2
% change 89-02				
OR	22.2%	9.4%	10.0%	18.3%
CA	3.7%	-10.8%	-6.2%	-1.3%
ID	-29.9%	-22.9%	-0.6%	-11.4%
UT	-15.2%	-24.7%	-6.9%	-12.3%
WY	11.8%	5.9%	0.7%	7.2%
WA	-1.7%	4.6%	10.8%	3.5%
OR Rank	1	1	2	1
UT Rank	5	6	6	6

Notes: * 1 = Highest state, 6 = lowest