Exhibit No. ___(RJF-1T)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY Respondent.	)	**Docket No. UE-032065**

REDACTED

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS

OF NORTHWEST UTILITIES

July 2, 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 No.___(RJF-2).

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 GRID model study of normalized net power cost for the pro-forma period, April 2003 to March 2004. I identify a number of problems in the GRID study that overstate the Company's revenue requirement. I also address the Company's proposed "Multi-State Process ("MSP") Solution" and other revenue requirements issues related to power costs.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Table 1 summarizes my recommended test year net power costs and other revenue requirements adjustments. My major findings are as follows:

1. PacifiCorp's request for $553.0 million in (Total Company) net power costs is substantially overstated. I recommend a number of net power cost adjustments, resulting in a reduction to Washington net power costs. Table 1, below, summarizes the impact of each of my proposed adjustments.[1/]

Short-Term Transaction Adjustments

2. PacifiCorp excludes zero cost power arising from the settlement of a dispute with the Bonneville Power Administration ("BPA"). The Company's standard practice is to include all known transactions whether they end in the pro-forma period or not. For consistency, this transaction should be included in the GRID study.

Long-Term Contract Adjustments

3. PacifiCorp used Black-Scholes modeling (or "options theory") in its evaluation of the Morgan Stanley and Sempra call options. This method assigns an "option value" to resources that is not reflected in GRID. While the Company models all of the costs of these resources in its test year, it ignores the "option value" that led it to select these contracts in the first place. I recommend imputation of an option value for these contracts.

4. In its evaluation of the West Valley lease, PacifiCorp also used Black-Scholes modeling and ascribed a substantial option value to the project. Without this assumed benefit, West Valley would have been an uneconomic resource for the Company. Consequently, I also recommend imputation of an option value for West Valley.

5. The Company includes costs related to System Integrity curtailment rights for the P4 contract. However, the Company assumes no curtailments will occur under normalized conditions. To provide a balanced treatment, I propose an adjustment to match the costs and benefits of this contract.

6. PacifiCorp has entered into hydro and temperature hedges. However, the GRID study includes only the premium cost of the hedges, but no benefits. I recommend removal of the cost of these hedges and rejection of PacifiCorp's proposed Schedule 96.

[1/] The Washington allocation factor of 8.96% shown is a estimated composite rate based on Exhibit No.__(JTW-3) at 5.1.

7. PacifiCorp overstates generation from the Fort James cogeneration facility compared to recent actual levels. Correcting this error reduces net power costs.

Thermal Dispatch Adjustment

8. The GRID model produces an unrealistic and highly questionable dispatch of coal units. As a result, GRID understates the generation that can be expected from the Company's coal plants. Correcting this problem by increasing the market size limit reduces power costs by allowing more spot sales to take place.

Outage Adjustments

9. A major cause of the increase in power costs occurring since Docket No. UE-991832 has been the increase in outage rates of PacifiCorp's thermal generators. Outages occurring over the past four years are reflected in GRID via unit thermal deration inputs. The Commission should not allow a decline in performance to result in a financial reward for the Company. I recommend ten outage rate adjustments to address this problem and to provide more representative power cost estimates.

10. The Commission should pro-forma out the impact of the Hunter Unit 1 outage from November 2000 to May 2002. The Company has excluded the impact of this outage in power cost studies it filed in its most recent cases in Oregon and Utah, and has not demonstrated in this proceeding that this outage was not the result of imprudence.

11. GRID uses overstated outage rates for its new Combustion Turbines ("CTs"). The Company included numerous outages that occurred during initial operation and testing of these units that should not be expected to recur.

12. The Company included inappropriate outages for several other plants in its historical data. For example, PacifiCorp included an outage at Bridger Unit 4 that the Company has already admitted was imprudent. It also included other outages and derations related to other imprudent or unusual problems that have now been corrected at Hunter and Blundell. The impact of these outages should be reversed as well.

13. I further recommend the Commission pro-forma out several abnormal or "catastrophic" outages to provide a better representation of normalized power costs. The Company has previously proposed to pro-forma out these outages in prior cases in Oregon and Wyoming.

14. The Company also includes many minor outages that it admits were due to errors of Company personnel or contractors. I recommend the Commission remove the impact of these events.

<u>Other Power Cost Adjustments</u>

15. The Company substantially understates the capacity of the Wyodak unit by modeling an unsupported seasonal capacity rating. My review of several years of actual data reveals no difference between the summer and winter capacity or energy generation of this resource.

16. The GRID study assumes very unrealistic operation of its gas-fired units. For example, GRID assumes CTs will start up during low load hours, and run at a minimum for many hours. In actual operation, this doesn't occur. The Company also acknowledges GRID cannot capture the quick start benefits of these units. Correcting these problems further reduces power costs.

17. The Company includes a substantial emergency energy purchase on February 29, 2004. This purchase was the result of a data entry error in the model that should be corrected.

18. GRID produces abnormally high heat rates for Gadsby and West Valley resulting in an overstatement of fuel costs.

<u>Non-Power Cost Adjustments</u>

19. PacifiCorp obtained a $7.5 million concession from General Electric ("GE") when it negotiated the Gadsby combustion turbine purchase. This credit was realized as a waiver of a combustion turbine's rental fees, not as a reduction to the cost of the project. By structuring the credit in this manner, the Company retained the benefit for itself instead of customers. I recommend a rate base offset in this amount because the Company had a conflict of interest in its negotiation for this concession and customers are entitled to the credit for this high cost resource.

20. PacifiCorp has an eighty-year contract to provide Western Area Power Administration ("WAPA") transmission service. Regulators in both Oregon and Utah have made imprudence disallowances related to this contract because it lacks any price escalation provisions. I recommend a similar disallowance.

<u>Multi-State Process Adjustments</u>

21. The Commission should reject the "MSP Solution" or original "Protocol" methodology for jurisdictional allocation. PacifiCorp has already

abandoned its filed Protocol as its preferred MSP Solution in Oregon and Utah. For this reason and others, it makes no sense for the Commission to adopt the Protocol methodology. Because the Company has failed to present the Commission with a reasonable jurisdictional allocation methodology, I recommend the Commission reject the PacifiCorp rate filing or bifurcate the case and determine the jurisdictional allocation method in a subsequent phase.

22. Alternatively, if the Commission is inclined to adopt the original Protocol framework, I recommend a series of adjustments. First, the Protocol does not contain a reasonable Hydro Endowment for Northwest customers. The PacifiCorp method allocates 100% of the cost of hydro to the Northwest, but does not allocate many of the benefits of hydro to the Northwest. I propose adjustments to correct this defect.

23. The Protocol fails to address the issue of cost-shifting among the states. This and several other problems must be addressed in any resolution to the MSP. I recommend an adjustment to address the cost shifting problem.

Q. DO YOU BELIEVE YOUR PROPOSED TOTAL COMPANY NET POWER COST FIGURE IS REALISTIC IN LIGHT OF PACIFICORP'S RECENT ACTUAL POWER COSTS AND OTHER FACTORS?

A. Yes. While recent actual power costs exceed the levels that both the Company and I are recommending in this case, power costs continue to trend downwards from the levels occurring during the power crisis. In addition, the Northwest experienced poor hydro conditions for the year 2003 increasing actual power costs. Also, recent actual loads exceed the normalized test year loads.[2/]

Further, the Company used the same test year (FY 2004) for its most recent Utah rate case (Docket No. 03-2035-02). In Utah, PacifiCorp accepted a settlement resulting in an overall power cost figure quite consistent with my recommendations in this case. Exhibit No.__(RJF-3) is copy of an exhibit filed by the Company in the Utah proceeding in support of the Utah stipulation. I have

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2/ However, increasing loads would also increase billing units, and would likely decrease rates overall.

added an analysis to the PacifiCorp document that shows the Company's power cost settlement in Utah is consistent with a Total Company power cost of approximately $499.7 million. This level is quite consistent with my recommendation in this case.

Following is a table summarizing my recommended adjustments.

Table 1
Summary of Recommended Adjustments
$1000

Reference:	Total Company	Washington Basis 8.96%
1 PacifiCorp Request	$553,004,514	$49,550,950
A. Short-Term Transactions	-$6,861,000	-$614,767
2 BPA Settlement Adj.	-$6,861,000	-$614,767
B. Long Term Contract Adjustments	-$12,879,710	-$1,154,063
3.1 Morgan Stanley Call	-$2,388,754	-$214,040
3.2 Sempra Call	-$858,335	-$76,909
4 West Valley	-$3,116,000	-$279,203
5 P4 Production	-$486,000	-$43,547
6.1 Aquila hydro hedge	-$1,750,000	-$156,806
6.2 Aron Temperature Hedge	-$2,100,000	-$188,167
6.3 Morgan Stanley Temp Hedge	-$1,800,000	-$161,286
7 Fort James	-$380,621	-$34,105
C. Modeling Adjustments	-$33,139,630	-$2,969,415
8 Increase Market Size Limit	-$9,871,166	-$884,488
9 Outage Rate Adjustments		
10 Hunter Unit 1 Outage	-$7,660,533	-$686,408
11 CT Outage Rates	-$719,994	-$64,514
12.1 JB 4 Outage	-$468,910	-$42,016
12.2 Hunter Transformer Outages	-$2,207,033	-$197,757
12.3 Blundell Deration	-$70,974	-$6,359
12.4 Hunter 3 Outage (Prudence)	-$340,018	-$30,467
13.1 DJ 3 Catastrophic Outage	-$1,180,573	-$105,783
13.2 HDN - 1 Catastrophic Outage	-$329,277	-$29,504
13.3 Colstip 4 Catastrophic Outage	-$492,950	-$44,170
14 Other Company Error Outages	-$600,475	-$53,804
15 Wyodak Capacity	-$1,811,003	-$162,272
16 CT Dispatch Logic/Quick Start	-$1,267,461	-$113,569
17 Emergency Energy Adjustment	-$2,933,253	-$262,829
18 Gadsby/ West Valley Heat Rates	-$3,186,011	-$285,477
Total Power Cost Adjustments -	-$52,880,340	-$4,738,245
Allowed	$500,124,174	$44,812,704
D. Non-Power Cost Issues		
19 Gadsby CT Rate Base	-$1,125,000	-$100,804
20 WAPA Transmission Contract	-$5,551,913	-$497,469
Total Non-Power Cost	-$6,676,913	-$598,272
E. MSP Issues		
22.1 Full Hydro Fuel Credit	$0	-$858,339
22.2 Reserves and Load Following	$0	-1,926,243
23 Gadsby/West Valley Treatment	$0	-$856,249
Total MSP Adjustments	$0	-$3,640,832
Total All Adjustments	-$59,557,253	-$8,977,350

II. NET POWER COST ISSUES

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

A. Net power costs are the variable production costs related to fuel and purchased power expenses, and net of power sales revenue. Power costs comprise a substantial portion of the overall revenue requirement, and thus, are a significant component of PacifiCorp's proposed base rates. In Docket No. UE-991832, the Company requested $487 million in net power costs. In this case, the Company is requesting $553 million. Based on the proposed allocation factors, this $66 million increase in system level power costs is responsible for approximately $5.9 million in increased revenue requirements for Washington, or 22% of the requested increase of $26.7 million.

Short-Term Transaction Modeling

Q. DESCRIBE THE SHORT-TERM TRANSACTIONS MODELED IN GRID.

A. There are two types of short-term transactions modeled in GRID. Short-term firm transactions are firm contracts with a term less than one year. GRID does not forecast or simulate such transactions. Rather they are just a fixed input with pre-determined energy volumes and prices.[3/] For short-term firm transactions, the Company normally inputs all known contracts that were arranged by the time of the rate case filing date. However, the Company has excluded one important contract, as I shall discuss shortly.

3/ The model *accounts* for such transactions rather than *simulates* them. No matter what else changes in the model, the short-term firm transactions will remain constant in GRID.

System balancing transactions (hour to hour trades) are simulated in GRID. The model either sells or purchases this product at prices based on the forward curve as needed to balance the system.

Q. DID PACIFICORP USE ACTUAL SHORT-TERM FIRM TRANSACTIONS IN ITS MOST RECENT CASE IN WASHINGTON?

A. No. In Docket No. UE-991832 the Company developed "normalized" short-term firm transactions. These assumptions were developed from historic volume levels with normalized price assumptions.

Q. HAVE ACTUAL SHORT-TERM TRANSACTIONS BEEN USED IN PRIOR PACIFICORP CASES BY COMMISSIONS IN OTHER STATES?

A. Yes. In the last three PacifiCorp Utah general rate cases, the Utah Public Service Commission ("PSC") used actual short-term transactions as the basis for computing net power costs. In addition, in the most recent Wyoming case the Commission also used actual short-term firm transactions. In the most recent Oregon rate case, the Company used a fully projected test year, but did include transactions that were known as of the filing date. However, for states where a historical test year has been used, it is the practice of the Company and regulators to use actual transactions as the basis for modeling short-term firm contracts.

Q. DOES THIS PROCEDURE CREATE ANY PROBLEMS THAT NEED TO BE ADDRESSED?

A. Yes. There are at least two issues that should be considered. <u>First</u>, it is not possible in this case to include all short-term firm transactions because the actual data will not be available to parties in sufficient time for analysis and inclusion in their direct testimony. This is acceptable for purposes of this case, however.

Second, the Company did not include all of the short-term firm transactions it was aware of when it filed its case. Notably, the Company excluded a zero cost transaction with BPA.

Q. EXPLAIN THE CIRCUMSTANCES SURROUNDING THIS BPA POWER AND HOW IT HAS BEEN TREATED IN OTHER STATES.

A. Between November 16, 2000, and April 4, 2001, PacifiCorp mistakenly delivered power to BPA because of a faulty meter owned by BPA. After PacifiCorp filed an action against BPA in the U.S. District Court, PacifiCorp and BPA agreed that BPA would deliver to PacifiCorp 100 megawatts ("MW") of firm energy in July and August 2003 and 50 MW of firm energy in October 2003. Thus, the Company was to take delivery of 41,600 megawatt hours ("MWh") of on-peak power in July and August 2003 and 21,600 MWh in October 2003. Thus, the Company is receiving this power from BPA during the pro-forma period in GRID.

The Company has argued in other states that customers who did not pay for the costs of the power crisis should not receive any benefit related to the BPA settlement. As a result, it did not include the BPA transaction in its test year in either Utah or Wyoming. However, it did provide a credit on its 2001 excess power cost deferral in Oregon due to the BPA transaction as part of the settlement of UE 147 (the 2003 Oregon general rate case). Because of the "black-box" nature of the settlement in the 2003 Utah case it is not possible to determine the specific treatment of the BPA power in that state. However, it was an issue raised during settlement discussions. In Wyoming, the Commission rejected the PacifiCorp request for deferral of excess power costs incurred during the power crisis in 2003 (Docket No. 20000-ER-02-184). In addition, the Wyoming Commission established a principle in that same case holding that certain one-time or non-recurring items should be excluded from the test year. Because the BPA transaction is a one-time event, no party supported an adjustment related to this issue in Wyoming.

Q. DOES THIS MEAN YOU AGREE THAT THE BPA POWER SHOULD BE EXCLUDED IN WASHINGTON AS WELL?

A. No, the underlying circumstances are substantially different. First, PacifiCorp never requested direct recovery of excess power costs in Washington during the power crisis. Had the Commission denied such a request, there might be some basis for excluding this contract, as in Wyoming.

Second, even in the states where PacifiCorp was allowed recovery of excess power costs, according to the Company's various estimates and testimony, the excess power costs ultimately allowed were far less than the actual excess power costs incurred by the Company. Typically the Company assumed it obtained recovery of 50-75% of its excess power costs. As a result, there are no customers in any state that paid 100% of the PacifiCorp excess power costs during the power crisis. Therefore, a substantially different treatment in Washington versus other states seems misplaced.

Third, under the terms of the five-year rate plan agreed to in Docket No. UE-991832, the Company was not eligible to file for a new rate case in Washington until July 2005. In Docket No. UE-020417, the Company requested relief from the rate plan, ostensibly on the basis of financial exigency created by the power crisis and equity vis-à-vis other states that had already borne some of the costs of the crisis. In allowing the Company to file a rate case before the end of the rate plan, the Commission has granted the Company's request to address certain costs associated with the power crisis in Washington. In short, without the power crisis, the rate plan likely would have never been re-opened, and PacifiCorp would not be filing a case until July 2005. The Commission's order in Docket No. UE-02417, strongly supports this view:

> 16. PacifiCorp, however, now contends "the Rate Plan has resulted in dismal financial statistics for the Company's Washington operations." *PacifiCorp Brief at 1.* The root cause for this, PacifiCorp argues, is the "Western energy crisis of 2000-2001." *Id.*. . . According to PacifiCorp, the important consequence of having borne both the increased power costs in earlier periods, and during the period for which it seeks relief, is that the Company has been "stripped . . . of its ability to absorb the normal, more routine cost increases in the months and years remaining in the Rate Plan." *PacifiCorp Brief at 2.*[4/]
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> 22. On balance, considering all the evidence, we determine that PacifiCorp has not borne its burden to demonstrate entitlement to deferral accounting or immediate rate relief.
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> 23. *We do, however, conclude that the record, considered as a whole, demonstrates that the Rate Plan has been so overtaken by events that it no longer is in the public interest for the Company's rates to remain unexamined through the Rate Plan Period.* We emphasize that the record in this proceeding is not an adequate one upon which to conclude that PacifiCorp's current rates are not fair, just, reasonable, and sufficient. The record here, however, is adequate to bring into question whether that standard will be satisfied when considered in light of a current test year with properly restated, normalized, and pro formed results. PacifiCorp's Washington operations have not been thoroughly reviewed on a full general rate case record in 17 years. *Such an examination is*

4/ Re PacifiCorp, WUTC Docket Nos. UE-020417, UE-991832, Eighth/Sixth Suppl. Order at 7-8 (July 15, 2003).

long overdue and seems absolutely imperative in the wake of the recent power market crisis....[5/]

Consequently, the argument that Washington ratepayers did not pay for higher power costs during the power crisis does not hold water. Indeed, without the power crisis, this proceeding would not be taking place and ratepayers would not now be facing the prospect of higher rates. As a result, exclusion of the BPA transaction resulting from circumstances that contributed to the power crisis is inequitable.

Finally, unlike the current practice in Wyoming, the Company does not exclude one-time items from its calculation of power costs in Washington. Indeed, the Company has entered into several short-term contracts in the past year that all start and end prior to the end of the pro-forma period.[6/] Consequently, there is no basis for excluding the BPA contract on the basis of it being a "one-time" or non-recurring event as the Company does not make this adjustment for many other similar items in the test year. *If* the Commission is to exclude this item, it should also examine all of the thousands of other short-term firm contracts, and other types of contracts and make adjustments to remove all such arrangements that are not out of line with the current market. Inclusion of the BPA contract in GRID reduces power costs by the amount shown in Table 1.

5/ Id. at 10-11 (emphasis added).

6/ These include the LADWP and Anaheim exchanges and the Desert Power Contract.

Long-Term Contract Modeling In GRID

Q. DOES GRID MODEL LONG-TERM POWER CONTRACTS?

A. Yes. The Company includes the costs and energy produced by all of its long-term contracts in GRID, along with thermal resources in order to project normalized power costs. For certain types of contracts, however, the Company does not (and for the most part cannot) reflect all the benefits of these transactions in GRID. These include various options and hedges, along with certain other interruptible contracts. I will discuss each type of contract in the following sections of my testimony.

PacifiCorp Option Contracts

Q. HAS PACIFICORP ENTERED INTO ANY OPTION CONTRACTS?

A. Yes, the Company has included the Morgan Stanley and Sempra call option contracts in its GRID study. Further, the Company has evaluated other resources (most notably the West Valley lease) by determining an "option" value of the resource. In a number of cases, the Company made its resource selection decisions on the basis of Black-Scholes modeling, which is also known as "options theory."

Q. WHAT ARE THE BASIC ASSUMPTIONS UNDERLYING THE BLACK-SCHOLES EQUATIONS THAT MUST BE SATISIFIED?

A. Black-Scholes requires that the market for the options evaluated be efficient, interest rates are stable and known, the stock pays no dividends, no commissions are charged, and the stock returns are log-normally distributed.

Q. TELL US MORE ABOUT THE APPLICATION OF BLACK-SCHOLES MODELING IN SECURITIES TRADING APPLICATIONS.

A. Based on my review of the literature, it is a commonly applied technique. However, that is not the same thing as saying it has always been successfully applied. The Black-Scholes equations were used extensively by the infamous hedge fund, Long Term Capital Management ("LTCM"). LTCM was the fund directed by two Nobel Laureates, Myron Scholes and Robert Merton, that threw the financial world into near calamity. Exhibit No.__(RJF-4) is an excerpt from the transcript of a February 8, 2000 episode of Nova on the Public Broadcasting Service, which summarizes the LTCM debacle. It shows that even with the help of two of the Nobel Laureates credited with developing the Black-Scholes equations, the dynamic hedging methodology used by LTCM failed to predict market movements, and nearly resulted in an epic collapse of the financial system.

Q. IS BLACK-SCHOLES AN ACCEPTED THEORY FOR VALUING ENERGY RESOURCES?

A. While the aforementioned underlying assumptions of the method may be applicable for evaluation of financial instruments, they may not apply in the case of energy derivatives or physical energy resources. PacifiCorp has not provided any evidence in this case that the four criteria discussed above are met for the types of power resources it has applied options modeling to. As a result, there is no proof that Black-Scholes works as intended for selection of energy resources.

Q. ARE YOU SAYING USE OF BLACK-SCHOLES MODELING FOR RESOURCE SELECTION DECISIONS IS IMPRUDENT?

A. At the very best it is unproven, novel and highly speculative. The Commission might consider disallowing the costs of resources selected by the model on the basis of imprudence. However, there is another, more fundamental problem in that the benefits ascribed to resources by the Black-Scholes modeling are for all practical purposes impossible to reflect in a rate case test year. Thus, PacifiCorp is in the situation of having selected resources on the basis of certain speculative benefits that it will never reflect in a rate case setting.

Q. PLEASE EXPLAIN FURTHER.

A. The Company's proposed treatment of resources evaluated using Black-Scholes is asymmetric because it includes 100% of the resource cost, but does not reflect the options value that lead the Company to select these resources in the first place.

Q. PLEASE EXPLAIN THIS PROBLEM.

A. To illustrate the problem, I will describe a hypothetical call option ("Option X") for on-peak power, similar to the Morgan Stanley call. Option X would allow PacifiCorp to purchase one MWh of Heavy Load Hour ("HLH") power in July at a price of $50/MWh and the option has a cost of $10 dollars. Further, assume PacifiCorp's forward curve for July shows an on-peak (HLH) price of $40/MWh. Based on the forward curve the "intrinsic value" of the option is zero because the strike price ($50/MWh) is greater than the expected forward price, $40/MWh. In other words, the energy available from the option is expected to be "out of the money."

Q. WHY WOULD THE COMPANY MAKE SUCH A PURCHASE?

A. PacifiCorp may be concerned that its forward curve could be wrong. Power prices are both uncertain and potentially volatile. As a result, the Company attempts to limit its exposure to the risk of higher than expected prices by purchasing the option. The value of the option exists only because of price volatility.

Assume, for example, that PacifiCorp has a high, medium, and low price forecast, all assumed equally likely to materialize. Assume the high forecast is \$83/MWh, the medium is \$40/MWh, and the low is \$30/MWh. Under this scenario, the option has a 33% chance of saving PacifiCorp \$33 (\$83-\$50), but a 67% chance of providing no benefit at all. This produces an "expected value" savings of 1/3 of \$33 plus 2/3 of \$0, or \$11. As a result, PacifiCorp would compute an expected value of savings of \$11 dollars, for an option that would cost them only \$10. Consequently, the Company contracts for the option because its "option value" (or "extrinsic value") of \$11 exceeds the option price of \$10. In this case, the extrinsic value of the option provides the entire justification for purchasing the option.[7/]

Q. WILL THE CONTRACT ACTUALLY RETURN \$11 OF VALUE?

A. No, the amount returned will be either \$33, or 0. This is really the same thing as the fact that a roll of a die will return a digit from one to six, while the expected value of the roll of a die is 3.5.[8/] The expected value of an outcome may not even be one of the possible outcomes. The expected value is only expected to

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7/ The methodology using the Black-Scholes equation is more elegant and comprehensive, but this example illustrates the concept.

8/ 3.5 = 1/6(1+2+3+4+5+6)

materialize "on average" if there are a very large number of similar circumstances over time.

Q. IS THE ABOVE DESCRIBED EVALUATION OF THIS OPTION UNREASONABLE?

A. For purposes of this example, no. The problem, however, is that in rate cases, the Company sets power costs using a much different kind of model. GRID deals only with a single mid-point forecast of prices. In the example above, GRID would use the $40/MWh forward price, not the low, medium and high range of price forecasts. Therefore, in GRID, this transaction would never show any benefit, even though PacifiCorp's options modeling shows the transaction to be a good deal.

The problem is that PacifiCorp sets rates using GRID, which treats price as a <u>deterministic</u> variable. However, it based this resource selection decision on its options modeling which treats price as a <u>stochastic</u> variable. The lack of stochastic price modeling in GRID means that customers can never see all of the benefits of the call option (such as the Morgan Stanley contract) considered in the decision to acquire the resource. In the above example, GRID would show a cost of $10, but would not show the expected value benefit of $11. Instead, GRID would say the option was worthless. In this example, PacifiCorp would charge customers a cost of $10 in GRID and have a 33% chance of a $33 benefit. In effect, the Company has found a way to get ratepayers to pay its cost of $10 in order to give the Company a one-third chance to win $33. This would be much the same as PacifiCorp including the costs of lottery tickets as an operating expense, but claiming that on a normalized basis, the winnings are always zero. In my view, this is not a reasonable ratemaking expense because there is no way to match costs and benefits, and prudence is more of an academic question.

Q. DOES THIS APPLY TO THE MORGAN STANLEY CALL OPTION?

A. Yes. Confidential Exhibit No.__(RJF-5C) is a copy of Confidential Exhibit PPL/802 from a recent Oregon proceeding.[9/] This exhibit shows PacifiCorp's evaluation of the [redacted]

9/ Re PacifiCorp, Oregon Public Utility Commission ("PUC") Docket No. UE 134 (the West Valley case).

[redacted] This is a great return on an investment that PacifiCorp pays for using other people's money.

Q. THE ONLY WAY IN WHICH THE OPTION HAS VALUE IS IF MARKET PRICES INCREASE ABOVE THE FORECAST. HOWEVER, IF THAT HAPPENED, PACIFICORP'S POWER COSTS MIGHT INCREASE OVERALL. IN LIGHT OF THIS, IS YOUR COMPLAINT ABOUT THIS STILL A FAIR CRITICISM?

A. Yes, and for at least three reasons. First, recall from the above example that price variation is a two way street – prices may either be *above or below* the forecast. PacifiCorp wishes to include a cost that limits its risk when prices are high, but it does not consider that benefit in the GRID or the equally probable chance that prices will be below its trading curve forecast. A balanced analysis of the problem would require both scenarios be considered, not just the high price case.

Second, why is it reasonable for PacifiCorp to be able to charge customers for protecting its shareholders from price volatility? What if the situation were reversed? PacifiCorp could also *sell* call options, where it is effectively betting prices will not exceed expectations. The same methodology it uses to justify purchasing call options could be used to justify selling call options. Selling call options would produce a credit to net power costs and provide income. However, under the PacifiCorp methodology, GRID would show the income from the option sales, but would not reflect any of the possible costs.

If the modeling method used in GRID were fair, it should apply equally in the case of either purchase or sale of call options. Instead, call purchases benefit

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10/ This is most certainly *not* a case where changed circumstances (e.g., lower than forecast prices) resulted in a prudent contract later appearing to be uneconomic. Rather, by design, the contract is expected to produce costs well in excess of benefits, based on the forward curve used by the Company.

the Company unfairly, while call sales benefit ratepayers. Returning to the lottery ticket example, PacifiCorp would be loathe to include income from selling lottery tickets, without also including an offset for the risk it would have to pay the winner.

Finally, an increase in market prices might actually *increase* the profits PacifiCorp makes on wholesale sales by more than it increases the cost of purchases. Thus, higher market prices may actually *decrease* net power costs, overall.

Q. HOW COULD ONE ADDRESS THIS PROBLEM IN GRID?

A. The only way to provide a balanced analysis would be to run GRID with multiple price forecasts, just as it now runs with multiple water years. In this manner a wide range of price scenarios could be modeled and the full range of benefits of the call options reflected in the modeling. However, realistic modeling would probably be time-prohibitive because a full GRID run takes an hour or more at present.

PacifiCorp should not be allowed to use one type of model for making resource acquisition decisions and another model for ratemaking purposes. The Company should not be allowed to use a model for ratemaking purposes that can never show the benefits of those resources in the ratemaking context.

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS ISSUE?

A. I recommend the Commission impute the "option value" from these transactions to ratepayers. [redacted]

[redacted] I recommend the Commission impute the option values to these contracts in the amount shown on Table 1 for normalization purposes.

Q. ASIDE FROM MATCHING COSTS AND BENEFITS, IS THERE ANY OTHER REASON FOR THE COMMISSION TO IMPUTE THIS OPTION VALUE TO THE TEST YEAR?

A. Yes. If the Company is going to select resources on the basis of controversial modeling methods with speculative benefits, it should be required to reflect the assumed level of such benefits in the test year. In that case, it will have the incentive to make the most economic choices.

West Valley Lease

Q. ARE THE CALL OPTIONS THE ONLY EXAMPLE OF RESOURCES THAT THE COMPANY SELECTED BASED ON OPTIONS THEORY?

A. No. The Company evaluated the decision to sign the West Valley combustion turbine lease using the Black-Scholes methodology.[12/]

My analysis of the bid evaluation model demonstrates [redacted]

11/ Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 3.18(a)(iv)).
12/ Exhibit No.__(MRT-1T) at 13: 6-9.
13/ Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 3.18(a)(iii)).

[redacted] I recommend the Commission impute this option value against the cost of West Valley, as it is impossible to reflect this benefit in GRID. The impact of this West Valley adjustment is shown in Table 1. In addition, there are a variety of other issues associated with West Valley that I do not discuss here, which include the fact that West Valley is a lease from its affiliate Pacific Power Marketing.

P4 Production Company Contract

Q. ARE YOU CONCERNED ABOUT PACIFICORP'S MODELING OF ANY OTHER CONTRACTS?

A. Yes. The Company also has a contract with P4 Production Company (an Idaho operation) for interruptible power.

The P4 contract has three components: System Integrity, Operating Reserve and Economic Curtailment. The System Integrity clause allows the Company to interrupt 62 MW for twelve hours per year. GRID models the first two elements of the contract, although it may not fully reflect the associated benefits. PacifiCorp valued System Integrity clause at the Federal Energy Regulatory Commission's ("FERC") current price cap value of $250/MWh. This results in a cost of $40,500 per month, or $486,000 per year. The Company does not model this benefit in GRID, because it assumes that under normalized conditions a qualifying event would never occur.[14/] In GRID, the contract is modeled as a "no-energy archetype."[15/] Again, this is a situation where using a point estimate for hourly market prices (and failure to model outages in a

[14/] Exhibit No.__(RJF-7) (PacifiCorp's response to ICNU DR No. 1.5).
[15/] Which is just a fancy way of saying it does nothing.

probabilistic manner) has failed to capture all of the benefits the Company believes will exist in actual operation.

Q. HOW DO YOU RECOMMEND THE P4 TRANSACTION BE MODELED?

A. The value of the System Integrity clause is not modeled in GRID. However, the Company has modeled 100% of the associated costs. To achieve proper matching of costs and benefits, I impute additional power cost savings in the amount necessary to equalize the costs and benefits of this transaction. This adjustment reduces net power costs by the amount shown on Table 1.

Hedging Contracts

Q. ARE THERE OTHER TRANSACTIONS WHOSE BENEFITS ARE NOT REFLECTED IN GRID?

A. Yes. PacifiCorp includes the cost associated with the Aquila hydro Hedge and the J. Aron and Company and Morgan Stanley temperature hedges. These contracts are also modeled as "no-energy archetypes." In both cases, the primary benefit of these transactions is to reduce risk for PacifiCorp. However, there is no reflection of the hedge benefits in GRID. While I neither endorse, nor oppose, PacifiCorp's hedging efforts, it is not proper to reflect only the costs of hedges in setting normalized rates. Under "normalized conditions" hedges are not really a necessary ratemaking cost because only normal conditions apply.

For the hydro hedge, the Company makes payments to Aquila when actual hydro energy exceeds a certain level. In the case of poor water conditions, the Company receives a payment from Aquila. The Company pays Aquila $1.75

million per year, as the fixed cost of the hedge. Only this cost is included in GRID, with no reflection of the payments from Aquila.

Q. WOULD IT BE POSSIBLE TO MODEL THIS TRANSACTION IN GRID?

A. With some modifications it might be possible because GRID already simulates 50 water years. This logic could probably be modified to reflect the payments and credits under the contract. However, I do not recommend attempting to model this transaction in GRID, because the contract was never expected by PacifiCorp to produce a positive net present value. In fact, as structured now, the contract would result in PacifiCorp making payments in excess of receipts of $10 million[16/] over the five year term of the deal, based on the Company's Monte Carlo simulation of possible hydro conditions.

Q. WOULD DISALLOWING HEDGE COSTS DISCOURAGE PACIFICORP FROM UNDERTAKING PRUDENT RISK MANAGEMENT?

A. I believe that is unlikely. Confidential Exhibit No.__(RJF-8C) is a copy of a PacifiCorp presentation made regarding evaluation of the hydro hedge. This evaluation did not address cost recovery, but instead measured the earnings impact of the hedge. The primary benefit of the hedge shown in the analysis was to reduce the volatility in PacifiCorp's earnings. Based on this analysis it certainly appears that PacifiCorp undertook the hedge without any consideration of passing the contract costs and benefits through to ratepayers. Had the Company done so, there would be no earnings impact resulting from the hedge. For this reason, I believe it is safe to assume that the Company would undertake

16/ On an expected value basis.

such hedging strategies independent of rate treatment considerations. Ironically, if all costs and benefits of hedges were passed through to ratepayers, there would be no beneficial reduction in earnings volatility for the Company.

The primary benefit of this contract is not that it reduces *costs* for PacifiCorp, but rather that it reduces PacifiCorp's *risk* (i.e., exposure to higher than expected power costs when poor hydro conditions exist). However, there is no way in which this kind of benefit can be factored into the ordinary ratemaking process. In the end, this is just another "one-way street" where ratepayers pay the costs, while PacifiCorp stands to reap the benefits.

Q. COMMISSIONS TYPICALLY ALLOW INSURANCE PREMIUMS AS AN ORDINARY RATEMAKING EXPENSE. ISN'T THIS JUST LIKE AN INSURANCE POLICY?

A. No, there are some important differences. First, PacifiCorp not only pays a premium, it also makes payments to Aquila when hydro conditions are good. This would be like paying extra for storm damage insurance when less than the normally expected amount of storm damage occurred.[17/] Second, in the case of other kinds of insurance (for example property insurance) the benefits flow through to ratepayers in a variety of ways. For example, I understand that in the case of the Hunter Unit 1 outage, much of the repair cost was paid by insurance, and therefore, was not borne by ratepayers. While ratepayers may pay the cost of ordinary insurance, they also receive benefits that actually occur. In the case of the hydro hedge, there is no way in which ratepayers can obtain the benefits in the current GRID model, *and* the contract also produces expected costs in excess of

17/ This would seem like a very perverse form of a "good driver discount" if applied to car insurance.

the expected benefits. Finally, make no mistake, hedging is a higher risk endeavor than purchasing an insurance policy. Under the hydro hedge, for example, the Company could end up making very high payments to Aquila, with no payments in return. Further, these kinds of hedges are a new product without the long history behind them. This makes it difficult for the Commission to answer such questions as whether the amount of the premium is reasonable compared to the benefits. For example, is the premium of $1.75 million a reasonable price? What if it were five million? Or ten million?

Q. ARE THE TEMPERATURE HEDGES SIMILAR TO THE HYDRO HEDGE?

A. They appear to be quite similar. These instruments pay PacifiCorp in the event of high temperatures (hence high demand) and high market prices, or in the other extreme of low temperatures (thus low demands) and low market prices. Like the hydro hedge, there are no associated benefits modeled in GRID. Again, it appears the primary benefit of this contract is to reduce risk for PacifiCorp, but not costs. As discussed above, reduced risk is not possible to factor into the ratemaking process even if it was of value to ratepayers.[18/] As with the hydro hedge, I recommend it be removed from the GRID run. Removing the hedge contracts produces a reduction to net power costs by the amount shown in Table 1 of $5,650,000 (total company).

[18/] This arrangement is quite similar to the lottery ticket example above in that costs of the ticket are included, but it is assumed that there are no winnings under normalized conditions.

Q. DO YOU AGREE WITH PACIFICORP'S PROPOSAL TO USE A TEMPORARY CREDIT TO REFLECT A HYDRO HEDGE RECIEPT?

A. No. Mr. Griffith has proposed a temporary credit (Schedule 96) to pass through the hydro hedge benefits that occurred during the pro-forma period. I am concerned that adopting this treatment would set a precedent that would allow the Company to seek recovery of additional payments to Aquila or other hedge counterparties in the future. Further, this proposal does not address the problem of temperature hedges that produced no revenue credit in the test year. Finally, this proposal is an unnecessary complication. When faced with the same choices, the Wyoming Commission simply rejected recovery of the hedge premiums in their 2003 rate case.[19/] While the Oregon and Utah cases were settled, this topic was certainly an item discussed during the proceedings and no temporary credit was applied in either state.

__Fort James Cogeneration Project__

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF THE FORT JAMES COGENERATION PROJECT?

A. No. The Company has overstated the generation purchased from this project compared to recent actual data. It is apparent the generation from this project has declined over the past three years due to changes in production at the facility. Because this reduction appears to be continuing, I recommend use of a more recent twelve-month period to estimate generation from the project. Because the contract price exceeds market prices, PacifiCorp has overstated net power costs by the amount shown in Table 1.

19/ __Re PacifiCorp__, Wyoming PSC, Docket No. 20000-ER-03-198 (Feb. 28, 2004).

Thermal Dispatch Adjustments

Q. DO YOU HAVE ANY CONCERNS REGARDING MODELING OF THERMAL DISPATCH IN GRID?

A. Yes. I am concerned that the operations simulated for coal and gas-fired units in GRID are unrealistic. In reviewing the hourly dispatch logs, I have found many instances where coal units are turned down from full loading levels (often to minimum loading), while gas-fired plants run at minimum loading during the same hours. In some cases, gas units are being turned up, just as coal plants are being turned down. Exhibit No.__(RJF-9) is a table comparing the operation of the Jim Bridger 3 coal unit and Gadsby CT Unit 1 for a number of typical days. Based on my review of four years of hourly generator logs, this sort of operation for Bridger is unrealistic, but commonplace in GRID. In the end, I believe that the net result is to understate coal-fired generation, and eliminate some of the short-term balancing transactions that might otherwise take place under more reasonable operating assumptions.

Q. WHAT IS THE CAUSE OF THIS PROBLEM?

A. It is not possible to identify a single cause. However, it appears a contributing factor is the market caps modeled in GRID. Other factors may include reserve and regulation modeling.

Q. WHAT ARE THE "MARKET CAPS" IN GRID?

A. Market caps are assumptions built into GRID to control the volume of balancing transactions the model is allowed to make. During Heavy Load Hours, the Company assumes it can sell (depending on price) all of the excess generation it has. However, during Low Load Hours ("LLH") the Company assumes a cap of 60 MW for the California Oregon Border ("COB") market, 40 MW for the Desert Southwest, 110 MW for Mid-Columbia and 0 MW for SP15. This means that not all of the excess generation available from PacifiCorp's coal plants can be sold during the LLH.

Q. DO THE RESULTS STEMMING FROM THESE ASSUMPTIONS APPEAR REALISTIC?

A. No. The result is that in GRID, many of the lowest cost coal-fired plants on the system (Bridger, Cholla, Craig, Hayden, Naughton and Wyodak) are assumed to be turned down at night. Analysis of actual hourly logs for the most recent fiscal years demonstrates that this is not a realistic assumption. Exhibit No.__(RJF-9) also presents a graph comparing the GRID modeling results to the actual operation for Hayden 1. The figure shows a capacity duration curve developed over the most recent four fiscal years with the test year results from GRID. While GRID assumes the unit would run at a reduced loading for thousands of hours per year, in reality, the unit runs close to full loading 24 hours per day. This unrealistic pattern in GRID compared to actual is not atypical.

Q. WHAT IS THE IMPACT OF THESE MODELING ASSUMPTIONS?

A. The net effect is to increase net power costs. As a result of these turndowns, the coal units are unable to support profitable balancing sales in the model, and run at inefficient loading levels. In the end, coal-fired generation is lower than suggested by historical data.

Q HOW HAVE YOU ADDRESSED THIS PROBLEM?

A. My review of the hourly generator logs reveals there is some amount of turndown occurring for most of the units, but not as substantial as assumed in GRID. To address this problem, I increased the market cap limit by an amount necessary to more closely match historical sales levels and generator loading patterns. These additional sales decrease net power costs. This analysis supported an increase in the market caps of about 200 MW. Exhibit No.__(RJF-10) shows the generation levels in GRID, before and after my adjustments, and demonstrates that once adjustments are made for changes in system capacity, the proposed market caps produce generation consistent with actual historical operation.

Q. EXPLAIN THE ADJUSTMENTS SHOWN IN EXHIBIT NO.__(RJF-10).

A. In the period 1999 to 2003, there were a number of circumstances that changed PacifiCorp's coal-fired generation from the levels one should expect for the test year. First, the Company obtained the Gadsby and West Valley CTs. This resulted in less need to allocate coal-fired capacity to spinning reserve. Second, there were several major outages (including the Hunter Unit 1 outage) that I will shortly pro-forma out of the test year outage rates, again increasing generation. Third, PacifiCorp excludes Colstrip 3 from its test year, reducing expected generation. Fourth, PacifiCorp sold the Centralia plant, but did not replace all of the energy from the plant under the TransAlta buyback contract. Because the un-replaced Centralia generation may be made up by other coal units, historical generation levels should be adjusted upwards. Finally, in 1999, market prices were very low, likely resulting in economic turndowns of some coal-fired units. As test year market prices are much higher, these turndowns should be reversed.

Based on this analysis, on an adjusted basis, PacifiCorp's current fleet of coal-fired generators should be expected to produce 45.29 million MWh per year. This compares quite well to my final GRID study result of 45.26 million MWh per year. In contrast, the PacifiCorp GRID model result is only 44.4 million. Use of my proposed market cap limits produces a reduction in power costs in the amount shown on Table 1.

Thermal Deration Factors

Q. EXPLAIN THE IMPORTANCE OF THERMAL DERATION FACTORS IN GRID.

A. In GRID, thermal deration factors control how much generation is available from thermal units. The more energy available, the lower power costs. If a generator has an average outage rate of 5%, then GRID assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently on outage. The Company uses a compilation of outages over the most recent four-year historical period (April 1999 to March 2003) to compute the deration factors for thermal plants. The purpose of using four years is to "normalize" or smooth out variations that might affect a single year.

Q. ARE THERMAL DERATION FACTORS AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

A. Yes. PacifiCorp's thermal outage rates have increased substantially from the levels assumed in its last general rate case (UE-991832).[20] Exhibit No.__(RJF-11) shows that PacifiCorp's outage rates have increased by more than 20% compared to those used in the UE-991832 test year for the same plants. Because outage rates for larger units have increased by more than smaller ones, this has resulted in an increase of 32% in capacity on outage (i.e., the average amount of capacity out of service due to forced outages) assumed in the power cost study.

Q. HAS THE INCREASE IN OUTAGE RATES INCREASED POWER COSTS?

A. Yes. To estimate this cost I used GRID to compute the change in power cost resulting from a 10 MW change in coal capacity. I then applied this result to develop an annual average cost of the increased amount of capacity on outage. The result, also shown in Exhibit No.__(RJF-11), is $31.7 million on a total Company basis. In UE-991832 the Company requested $487 million in total power costs compared to $553 million for this case. My analysis demonstrates that close to half of the increase in power cost is due to a increase in outages rates of thermal plants.

A further problem is that the increase in outage rates has also lead to need for additional thermal capacity, further increasing system costs. The increase in

[20] These were also based on a four-year rolling average.

capacity on outage (226 MW) is more capacity than the entire West Valley plant.[21]

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS PROBLEM?

A. The Commission should take a very careful look at the causes of these increased outage rates and make adjustments to remove outages that are imprudent, non-representative, or abnormal. Considering that the Company is being allowed early relief from the requirements of the five-year rate plan, the Commission should not reward a decline in performance with higher rates. Consequently, a very high standard of proof should be required in the case of outage rate modeling.

Q. HAVE YOU IDENTIFIED ANY OUTAGES THAT SHOULD BE EXCLUDED FROM THE FOUR-YEAR ROLLING AVERAGE?

A. Yes. I have identified 9 major outage adjustments and a series of minor outages that should be removed from the four-year rolling average. These are shown on Exhibit No.__(RJF-12). The most significant of these is the Hunter Unit 1 outage from November 2000 to May 2001.

Q. WHAT IS THE BASIS FOR REMOVING THE HUNTER UNIT 1 OUTAGE?

A. This was clearly a catastrophic, one-time event. Hopefully it will never be repeated in the lifetime of Hunter Unit 1 or any other plant. As the Commission must certainly be aware, this outage occurred during the power crisis and had a devastating effect on PacifiCorp's power costs. Under PacifiCorp's modeling it is assumed that the Hunter Unit 1 outage would recur once every four-years. A

[21] Recall that the West Valley annual lease payment is nearly $15 million.

much more realistic assumption should be that such an outage will not recur again in the foreseeable future.

Q. DID PACIFICORP REMOVE THE HUNTER OUTAGE FROM ITS COMPUTATION OF GRID OUTAGE RATES IN ITS RECENT RATE FILINGS IN OTHER STATES?

A. PacifiCorp made adjustments to exclude the Hunter Unit 1 outage from its last two Oregon rate cases (UE 134 and UE 147), its most recent Utah case (Docket No. 03-2035-02) and its 2002 Wyoming rate case (Docket No. 20000-ER-02-184).[22/]

Q. ON WHAT BASIS DOES PACIFICORP JUSTIFY INCLUDING THE HUNTER OUTAGE IN THE FOUR-YEAR AVERAGES USED IN WASHINGTON?

A. In PacifiCorp's Response to ICNU DR No. 1.70, the Company stated as follows:

> The Company did not recovery Hunter 1 replacement costs in Washington as the Company did in Oregon and Utah. The Company used the same treatment as it did in Wyoming, which also did not provide recovery of Hunter 1.[23/]

As with the BPA settlement, I find this to be a very poor justification. As I pointed out above, a major reason this case is even taking place is because of the power crisis, which was most certainly exacerbated by the Hunter Unit 1 outage. It's unfair to say Washington customers did not pay for the Hunter Unit 1 replacement costs when the Company has been given early relief from its rate plan commitment.

22/ Because the Wyoming PSC ruled against recovery of the Hunter Unit 1 outage costs in the 2002 case, the Company later withdrew its proposal to pro-forma out the effects of the Hunter Unit 1 outage.

23/ Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR No. 1.70).

Further, there is a substantial distinction between Wyoming, which disallowed recovery of the Hunter Unit 1 outage, and Washington, where the Company did not even request recovery. As I noted in my testimony in UE-020417, the Company might have had the opportunity to attempt to recover Hunter Unit 1 costs at the time it filed for emergency relief in Oregon, Utah and Wyoming (in early 2001).[24/] Customers should not be overcharged in 2005 because PacifiCorp failed to act in a timely manner in 2001.

Finally, PacifiCorp has never recovered 100% of the Hunter Unit 1 outage costs in any state, even in Oregon and Utah. In fact, PacifiCorp estimates have placed the percentage of cost recovery in those states at 50% to 75%. As a result, the distinction between customers in Washington who were not asked to pay for the outage, and those in Oregon and Utah who paid for only part of this cost seems fuzzy at best.

Finally, the Hunter Unit 1 outage was an extremely complex event, and one that required substantial hearing time to investigate the prudence issue. No Hunter Unit 1 prudence evidence has been presented by the Company in this case.

In the end, the Hunter Unit 1 outage should be excluded as a very extreme and unusual event, and one whose prudence has not been established. I recommend an adjustment in the amount shown on Table 1 to pro-forma out this event.

24/ At that time the Company filed an increase request in its smallest jurisdiction (California) instead of making a timely request in Washington. Thus, I don't believe it is reasonable for the Company to suggest, as it did in Docket No. UE-020417, that it could not file in Washington in 2001 because it was too busy attempting to obtain recovery in its largest states.

Q. ARE THERE OTHER QUESTIONABLE OUTAGE ASSUMPTIONS IN GRID?

A. Yes. The Company has computed the deration factors for the Gadsby and West Valley CTs on the basis of their average operation over the brief period of time during the test year that these units were in operation (June 2002 to March 2003). To compute a four-year average outage rate the Company used actual data for one year, and a mature forced outage rate of about 4% for three years.

During this period of testing and initial operation, these units experienced an extraordinary number of outages. As a result, their outage rates averaged nearly 20%, and individual units had outage rates of 30%-45%. A more typical outage rate for CTs is 3%-5%. It is typical for new plants to experience start-up problems, though they rarely last for long. The Company assumes that these outages will repeat once every four years in their modeling.

In the comparable case of the Hermiston plant in Docket UE-991832, the Company assumed that a mature forced outage rate (also 4%) would be more representative of normal conditions until a reasonable period of historical data was obtained.

If the poor performance of Gadsby and West Valley truly is representative of future conditions, the Company should not be rewarded for it either. Use of a mature outage rate results in a reduction to power costs in the amount shown on Table 1.

Q. EXPLAIN THE CIRCUSMSTANCES SURROUNDING THE OUTAGE AT JIM BRIDGER UNIT 4 IN JUNE 2000.

A. This was a 315-hour outage resulting from a main transformer failure. This outage represents a case in which the Company has already admitted to imprudence. This is shown in the following excerpt from the cross-examination of PacifiCorp witness Barry Cunningham in Wyoming Docket No. 20000-ER-02-184.

> Q. (BY CHAIRMAN ELLENBECKER) Mr. Cunningham, have you ever been involved in a situation with PacifiCorp where there was an issue surrounding maintenance or testing or equipment integrity for a generation facility where the company did an examination and acknowledged either human or equipment or testing failure of its own making as being the fault?
>
> A. Yes, sir.
>
> Q. Can you illustrate one of those?
>
> A. The most recent one that comes to mind was a main transformer failure at the Jim Bridger Plant, and it would have been in the summer, I believe, of 2000. It was on, I believe, Jim Bridger 4 if I've got the units straight.[25/]
>
> * * *
>
> We had a spare transformer. It took us about two weeks, 13 days, as I recall, to replace it. This was again during the high-price power period, too.[26/]

Exhibit No.__(RJF-13) is a copy of the entire transcript section quoted above and it provides a more detailed description of the outage event. Because this outage was the result of imprudence, it should be removed from calculation of net power costs.

25/ Exhibit No. __ (RJF-13) at 3-4 (Excerpt of Transcript of Hearing Proceedings, Volume IV, Wyoming PSC Docket No. 20000-ER-02-184 at 558 (Jan. 13, 2003).

26/ Id. at 5.

Q. HAVE YOU IDENTIFIED OTHER SITUATIONS REQUIRING ADJUSTMENT TO THE PACIFICORP OUTAGE DATA?

A. Yes. There are two more instances where circumstances surrounding outages appear highly unusual and clearly non-representative of future conditions.

In the first instance, I discovered an extremely high number (87) of main transformer incidents at only a handful of units. While the North American Electric Reliability Council ("NERC") statistics demonstrate such problems are rare, for PacifiCorp, these amounted to the seventh leading cause of lost generation in a recent four-year period.[27/] Nearly half of these events (41) occurred at Hunter Units 1 and 2. Excluding the imprudent main transformer failure at Bridger 4 (discussed above), these Hunter incidents, including another catastrophic transformer failure at Hunter Unit 3, were responsible for virtually all of the lost generation due to main transformer failures that the Company has experienced in recent years.

Q. HAS THE COMPANY TAKEN ANY STEPS TO ADDRESS THESE TRANSFORMER PROBLEMS?

A. Yes. Based on PacifiCorp's Response to ICNU DR No. 1.71, the Company has now engaged in a program of acquiring additional spare transformers, improved monitoring and other improved procedures designed to resolve these problems. Based on PacifiCorp's Response to ICNU DR No. 3.22, the Company has included $1.488 million in capital costs and $185,000 in expense in the test year (total company) related to correction of these main transformer problems.[28/] In the

27/ October 1998 to September 2002.
28/ Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR No. 3.22).

case of Hunter Unit 2, there was a replacement made of the 2-2 main transformer in September 2001. There were no additional reported failures in the remainder of the historical data period (ending March 31, 2003).

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THIS ISSUE?

A. Whatever the cause of these problems, the Commission should recognize three important points. First, this level of outages is extremely high compared to other PacifiCorp plants, and to the utility industry in general. Second, the Company has taken steps to address the problem. Third, the Company seeks recovery of the costs of solving the transformer problem in base rates. While there are always outages at generators, and costs associated with solving them, in this instance the problem was unusual, and should not be expected to recur on a systematic basis. As a result, I recommend the associated costs be removed from the test year, resulting in a reduction to net power costs in the amount shown on Table 1.

Q. WHAT WAS THE SECOND ABNORMAL OUTAGE SITUATION YOU REFERENCED ABOVE?

A. The second example is less significant than the main transformer problem, but still requires an adjustment. The Blundell geothermal unit suffered a 3 MW deration from October 1998 to May 2001. This was due to turbine rotor stress corrosion cracking. This led to a month long outage to install a new turbine. However, this problem has now been corrected and the Company has included capital cost of $3.2 million in the test year related to installation of the new turbine.[29] PacifiCorp's normalization approach effectively assumes this problem

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[29] *See* Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR Nos. 1.73, 3.23 and 5.33).

was never solved, and will continue to occur. Again, I recommend removal of this problem, resulting in a decrease in test year net power costs in the amount shown on Table 1.

Q. EXPLAIN THE BASIS FOR EXCLUDING THE NOVEMBER 1999 HUNTER UNIT 3 OUTAGE FROM THE FOUR-YEAR AVERAGE.

A. Again, this is an instance of imprudence. In this case, the Company had to take the unit off-line for 141 hours to remove balance weights that were put in the wrong place in the generator. This error resulted in a vibration problem. Customers should not be required to pay for mistakes of this nature. The impact of this adjustment is shown on Table 1.

Q. ARE THERE OTHER EXAMPLES OF CATASTROPHIC OUTAGES THAT SHOULD BE REMOVED FROM THE FOUR-YEAR AVERAGE?

A. Yes. In September 1999, PacifiCorp experienced an 1030-hour outage at Dave Johnson Unit 3. In July 2000, the Company experienced an 1815 hour outage at Hayden Unit 1 and in July 2001, the Company had a 389 hour outage at Colstrip 4. PacifiCorp proposed a normalizing adjustment for all three outages in its requested power costs in Oregon case, UE 134.[30/] The basis for this adjustment was the Company's recognition that these events were non-recurring in nature. In addition, the Company also included all three outages on a list of catastrophic outages in the Utah Hunter/Excess Power Cost case. This is significant because in that case the Company indicated that it did not make forward purchases to cover

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[30/] While it did not propose any adjustment in Docket No. UE-147 (Oregon) and Docket No. 03-2035-02 (Utah), this issue was a factor during settlement discussions. As these cases settled, there is no evidence to prove these outages were included or excluded in those states.

such catastrophic outages. As a result, I recommend removal of these unusual and catastrophic outage events as well. The impact of this is shown on Table 1.

Q. ARE THERE ANY ADDITIONAL ISSUES RELATED TO GENERATOR OUTAGES?

A. Yes. The major outages discussed above are not the only examples of imprudent outages included in the GRID study. During the four-year historical period, the Company reported numerous other outage incidents to the NERC under the categories of "Operator Errors," "Maintenance Errors," "Subcontractor Errors" or "Other Safety Problems." These incidents resulted in lost generation of approximately 4.3 MW on average, every single hour of the historical period. These are imprudent outages and customers should not bear the associated costs.

Mr. Widmer's cross examination in the recent Wyoming case (in relation to the imprudent Jim Bridger 4 main transformer failure) underscores the need to address the rate treatment of these kinds of problem.

> Q. And are you aware that's the outage that one of the company's witnesses earlier said was the company's fault in the testimony that we just had over the past few days?
>
> A. Yeah. I believe Mr. Cunningham indicated that that was something that was a result of company actions. And we still don't recommend that that type of outage should be removed from the company's calculation. As in any business, you know, accidents happen, errors happen and so forth, and so *it appears to us that it's more of a normal occurrence.*
>
> *If, in fact, the company had a history of an exorbitant number of human errors in relation to this, I would expect the Commission to take notice of that.*[31/]

[31/] Exhibit No.__(RJF-14) at 4-5 (Excerpt of Transcript of Hearing Proceedings, Volume VII, Wyoming PSC Docket No. 20000-ER-02-184 at 1219: 21-1220: 9 (Jan. 16, 2003) (emphasis added)).

As Mr. Widmer has testified, the Commission should take notice of this large number of outages due to errors.

Q. IS THIS JUST "BUSINESS AS USUAL" FOR PACIFICORP?

A. Unfortunately, it appears to be the case. However, it does not need to be so. It is quite telling that for the four-year period ending December 1997, the Company reported only 112 hours of lost generation due to these four error categories. For the four-year historical period ending September 30, 2002, the Company reported 333 hours of lost generation, an increase of nearly 300%! Clearly, this represents an unacceptable decline in performance.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THIS ISSUE?

A. I recommend removing these costs from the test year resulting in a decrease to net power costs in the amount shown on Table 1 and Exhibit No.__(RJF-15).

Other Power Cost Adjustments

Q. DO YOU AGREE WITH THE CAPACITY RATINGS USED FOR WYODAK?

A. No. I have reviewed actual generator logs for the four most recent fiscal years and the Wyodak unit's actual output ran above its GRID capacity rating for thousands of hours during this period. The primary cause of this problem is PacifiCorp's use of a seasonal capacity rating for the unit. In GRID, the Company assumes a nameplate capacity rating of 252 MW from May to September and 276 MW the rest of the year.

Q. HOW DOES THE COMPANY JUSTIFY THIS ASSUMPTION?

A. The Company offers no analytical support. The Company has no data supporting a temperature versus capacity rating for the unit and the sole support for this assumption is an undocumented assumption suggested by plant personnel.[32/]

Q. DOES REVIEW OF FOUR YEARS OF HISTORICAL GENERATOR LOGS SUPPORT THE ASSUMPTION OF A SEASONAL CAPACITY RATING?

A. No. Because Wyodak is an air-cooled unit, one *might* expect a seasonal capacity differential. To test this assumption, I analyzed this issue in several ways. These analyses are shown on Exhibit No.__(RJF-16). First, I examined results from four years of average generator logs for the period April 1999 to March 2003. I compared the average daily peak capacity of the unit (for days when it was not on outage or maintenance) between the May to September period ("warm weather months") and the rest of the year. Based on my analysis, the average daily peak during the warm weather months was 276.0 MW. For the remaining months the average was actually lower, 275.3 MW.

Next, I examined average monthly generation for Wyodak over the period January 1998 to October 2003. While the warm weather months did experience a lower average generation than the remaining months, I believe generation in May and June is artificially suppressed due to the economic turndowns during the "fish flush" and scheduled maintenance. I found that the three summer months, July to September, had virtually the same as the average hourly generation as the coldest months (December to February). If there was a substantial difference in seasonal

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32/ Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR Nos. 3.21 Revised, 5.29 and 5.30).

capacity, I would expect that the winter months would have higher average generation than in the summer. It is significant that the average generation during the summer months, 262.9 MW, substantially exceeds the maximum capacity input used in GRID for those months (252 MW).

The figures also demonstrate that GRID understates Wyodak annual generation by 2.4% and generation during warm weather months by 9%. The data does not demonstrate any significant difference in generation in the summer months (July to September) as compared to the winter months of December to February.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE GRID MODELING OF WYODAK?

A. Yes. While the Company assumes a seasonal capacity rating in GRID, it did not assume a seasonal capacity rating in its computation of outage rates. This is significant because the formula used by the Company to compute outage rates is based on lost generation. Lost generation is based on the assumed maximum capacity of the unit. If the maximum capacity changes throughout the year, then the outage rate calculation should be adjusted.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THIS ISSUE?

A. I recommend removal of the seasonal capacity rating for the unit. The impact of this adjustment is shown on Table 1.

Q. DOES GRID PROVIDE A REALISTIC MODELING OF GAS UNITS?

A. No. While GRID shows coal plants backing down during the LLH, it shows CTs and the Gadsby Steam units coming on line during the same LLH. These gas units then run at minimum loading levels for several hours, before being brought up to full load. Refer again to Exhibit No.__(RJF-9) for a table showing GRID modeling of these gas units for a typical day throughout the year. In contrast, the actual logs show the CTs typically being brought on line and up to full load around 10 a.m.

The GRID modeling is rather inexplicable because it also shows many coal units running at minimum loading during the same LLH periods. This demonstrates the gas peaking units are not needed for reliability or reserve purposes.

Q. WHAT IS THE IMPACT OF THIS ERRONEOUS MODELING?

A. Fuel costs are overstated because generation is obtained from gas instead of coal-fired units. Also, the heat rates for the gas units are overstated because of excessive operation at inefficient loading levels.

Q. ARE THERE OTHER PROBLEMS IN THE GRID MODELING OF THE NEW CT UNITS?

A. Yes. In the past several cases in Oregon, Utah and Wyoming, the Company has agreed that GRID does not accurately model the ten-minute "quick start" benefits of Gadsby and West Valley. In the recent Wyoming proceeding Mr. Widmer testified that a new, pre-release version of GRID had improved quick start modeling and provided for approximately $1 million in quick start benefits. Mr. Widmer proposed to impute this benefit to the Wyoming GRID study. Notably, PacifiCorp has not imputed this benefit here.

Q. DO YOU HAVE A PROPOSAL TO ADDRESS THESE ISSUES?

A. Yes. I believe the above referenced quick start benefit should be imputed in this case as well. I have also developed a redispatch adjustment outside the model, removing the illogical generation of gas units during the LLH.[33/] These adjustments reduce net power costs by the amount shown in Table 1.

Q. GRID SHOWS A PURCHASE OF $3.007 MILLION FOR EMERGENCY ENERGY ON FEBRUARY 29, 2004. IS THIS REALISTIC?

A. No. According to PacifiCorp's Response to ICNU DR No. 5.42, this purchase is the result of a data entry error in GRID.[34/] Correcting this problem results in a reduction in new power costs in the amount shown on Table 1.

Q. ARE THE GRID HEAT RATE ASSUMPTIONS FOR GAS PLANTS REASONABLE?

A. No, GRID overstates the heat rates of the Gadsby and West Valley CTs.[35/] In the case of West Valley, the Company indicates that there is a data error in the GRID inputs.[36/] In addition, the dispatch modeling problems discussed above also contribute to an overstated heat rate because the model assumes these units will run at minimum load more than actual experience indicates. The average actual heat rates shown on the FERC Form 1 for 2002 are lower than those resulting from the GRID simulations. Correcting this problem results in the disallowance shown in Table 1.

33/ Mr. Widmer agreed to this adjustment in the Wyoming case as well.

34/ Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR No. 5.42).

35/ The heat rates in GRID also greatly exceed those used by the Company in its certification case for Gadsby and its own internal evaluations of West Valley.

36/ Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR No. 1.39).

Non-Power Cost Issues

Q. ARE THERE ANY ISSUES RELATED TO THE COST OF THE GADSBY COMBUSTION TURBINES?

A. Yes. The cost of the Gadsby CTs is exceptionally high (approximately $667/kW). In the Gadsby Certification case (Utah Docket No. 01-035-37), the Company contended that one of the benefits of the Gadsby project was the fact that GE had agreed to an early termination of a rental agreement for some temporary CTs at the Gadsby site. This resulted in a savings of $7.5 million for PacifiCorp. This benefit flowed directly through to the Company, not ratepayers. Had the Company obtained a simple price concession on the cost of the peaking units from GE, the Gadsby rate base would be reduced, potentially by the same amount. I am concerned that PacifiCorp had a conflict of interest in negotiating the purchase of the Gadsby CTs, as it may have had to choose between a lower permanent cost for ratepayers versus a one-time cost savings for PacifiCorp.

Q, ARE THERE ANY DOCUMENTS THAT SHED LIGHT ON THIS ISSUE THAT YOU WISH TO PRESENT?

A. Yes. Confidential Exhibit No.__(RJF-17C) is a copy of a portion of a PacifiCorp exhibit (Morrison Exhibit 6) presented by the Company in the Utah Gadsby CCN case, Docket No. 01-035-37. This document is a summary of information provided to the ScottishPower Board concerning the project. There are two interesting items contained in the Board presentation. First, the Board presentation states:

[redacted]

[redacted]

I believe this establishes three important points. [redacted]

This is a classic case of a conflict of interest that the Commission should resolve in favor of the ratepayers. I recommend the Commission disallow the $7.5 million from the Gadsby CT plant investment. The impact of this adjustment is shown on Table 1.

Q. PLEASE EXPLAIN THE WAPA WHEELING RATE ISSUE.

A. This is an issue that arose out of the transmission rate Utah Power and Light ("UP&L") charges the WAPA. In the Final Order in Docket No. 99-035-10, the Utah PSC recounted the history of this adjustment:

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[37] Exhibit No.__(RJF-17C) at 3 (emphasis added).

[38] Id. at 4.

> In 1962, Utah Power and Light Company entered into a fixed-rate contract of 80 years duration with the United States Bureau of Reclamation (later the Western Area Power Administration, WAPA), to wheel Colorado River Storage Project (CRSP) power over the Company's transmission system to public power "preference" customers. Some years later, Utah Power purchased CP National Corporation's Utah system, and thereby acquired a wheeling contract between CP National and the Bureau of Reclamation, having the same purpose and wheeling rate as the Utah Power contract. The wheeling rate in these contracts is $4.20 per kiloWatt-year; neither permits escalation.
>
> In Docket No. 82-035-13, Report and Order issued May 23, 1983, this Commission recognized that the contracts were not compensatory and ordered an imputation of revenues, based on the then-current Federal Energy Regulatory Commission (FERC) wheeling rate of $24.12, to prevent the subsidy that otherwise would flow from Utah Power's retail customers to CRSP preference customers. Revenue imputation for these WAPA contracts has been the Commission's policy since then.[39/]

Based on the same order, the Utah PSC determined that the lack of price escalators in an 80-year contract was imprudent. Thus, it imputed revenue to the contract based on the current FERC wheeling rate. The Company has filed its most recent cases in Utah with this imputed revenue as one of its scheduled adjustments.

Q. HAVE OTHER COMMISSIONS MADE A SIMILAR FINDING?

A. Yes. The Oregon PUC stated as follows:

> We hold that an adjustment needs to be made for the WAPA Wheeling contracts. . . It is reasonable to presume from this evidence that by using the Utah formula with the current FERC Wheeling rate, the Oregon adjustment should be $2.0 million. We adopt this amount as the adjustment to be made regarding these wheeling contracts.[40/]

39/ Re PacifiCorp, Utah PSC Docket No. 99-035-10, Report and Order at 43 (May 24, 2000).

40/ Re PacifiCorp, Oregon PUC Docket No. UE 116, Order No. 01-787 at 37-38 (Sept. 7, 2001).

I recommend the Washington Commission also make this disallowance. Based on PacifiCorp's Response to ICNU DR No. 1.26, application of the Utah formula for this test year would result in an additional disallowance in the amount shown on Table 1.[41/]

Q. IN PACIFICORP'S RESPONSE TO ICNU DR NO. 1.25, THE COMPANY SUGGESTS THAT IT DISAGREES WITH THIS ADJUSTMENT FOR WASHINGTON IN PART BECAUSE IT ASSERTS THE CONTRACT PRODUCES MORE REVENUE THAN COST. PLEASE COMMENT.

A. The Company provided no evidence in support of this contention, but I won't argue the point. The issue is not the relationship between revenue and cost, but rather the level of revenues that would have been produced by a prudent contract. Regulators in Utah and Oregon have made disallowances related to this issue, and Washington should do so as well.

III. MULTI-STATE PROCESS

Q. BRIEFLY EXPLAIN MSP.

A. The multi-state process, or MSP, concerns the allocation of the costs of resources among the six states and jurisdictions in which PacifiCorp operates. This issue originated with the PP&L and UP&L merger and remains an unresolved problem.

41/ Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR No. 1.26).

Q. THE PP&L – UP&L MERGER WAS APPROVED BY THE WASHINGTON COMMISSION IN 1988. WHY, AFTER 16 YEARS, IS THE ISSUE OF A JURISDICTIONAL ALLOCATION METHODOLOGY STILL A PROBLEM?

A. This is a fairly common problem for multi-state utilities. In cases where there is a "system agreement"[42/] such issues are resolved by the FERC. Because PacifiCorp has no system agreement, the FERC is not involved. However, FERC regulation of such agreements has frequently been a source of bitter controversy. Also, when mergers have occurred, there can be lingering problems 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 when approval of the merger was being sought. Rather, the Company offered to convene a jurisdictional allocation committee with all of the involved states only *after* approval of the merger was obtained.[43/]

The Washington Commission was clearly concerned about potential problems stemming from the combination of the two systems:

> 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

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42/ This is a contract that specifies the allocation of costs and resources among operating units in multi-state utilities. Examples include Southern Company, Entergy and AEP. Because such agreements generally control wholesale transactions, FERC regulates them.

43/ Re PacifiCorp, WUTC Docket No. U-87-1338-AT, Second Suppl. Order at 13 (July 15, 1988).

> 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.[44/]

The reference to "Pacific's" average system cost is significant, as it indicates that from that time, until there was a resolution of this issue, the Washington Commission was inclined to use the average power supply cost of the pre-merger PP&L as the basis for determining rates. It appears this was the "norm" expected to be followed until a new allocation method was agreed upon. A comparable passage is found in the Order of the Oregon Commission approving the merger:

> 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.[45/]

Consequently, it is well established that the differences in system costs for the PP&L system as compared to the UP&L system were a concern of the Washington and Oregon Commissions from the start. The applicants represented to various Commissions that shareholders would assume the risk of any failure to achieve a consensus concerning jurisdictional allocation. For example, in the Oregon merger case, we find the following passage:

44/ Id. at 14.

45/ Re PacifiCorp, Oregon PUC Docket No. UF 4000, Order at 22 (July 15, 1988).

> 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.[46/]

Similar language is found in the order approving the merger in the corresponding Utah case 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. [47]

> 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.[48/]

While the Company is now gravely concerned about this problem, its roots lie in the fact that there was apparently insufficient concern about it when the merger was first proposed.

46/ Id.

47/ Re PacifiCorp, Utah PSC Docket No. 87-035-27, Order at 62 (Sept. 28, 1988).

48/ Id. at 63-64.

Q. ARE THERE ANY OTHER IMPLICATIONS OF PACIFICORP'S ASSUMPTION OF RISK THAT THE COMMISSION SHOULD CONSIDER?

A. Certainly. When ScottishPower acquired PacifiCorp, it should have been aware of this potential problem. Proper "due diligence" should have identified *all* of the risks faced by PacifiCorp that ScottishPower has now assumed related to the risk of any failure to achieve consensus concerning inter-jurisdictional allocation.

Q. WHY IS THIS PROBLEM SO INTRACTABLE?

A. <u>First</u>, as pointed out in the passage quote 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 to deal with cost differences between the PP&L and UP&L systems. The major issue being the low-cost hydro resources on the PP&L system. Utah parties generally sought to eventually merge all of the costs of the system ("Rolled-In") and eventually obtained its share of the benefits of these hydro resources. Oregon and Washington parties preferred to preserve the benefits of hydro for the customers in the Northwest.

Recently, the Utah division resource shortfall and the disparity in growth rates among the states (Utah having the higher growth rates) has led to emergence of a new issue, cost shifting. Like the hydro issue, this has proven to be beyond resolution. Cost shifting is a potential outcome of a disparity in growth rates among these states. Underlying differences in attitudes of the states towards the desirability of growth and economic development may complicate this issue.

There have been temporary solutions, first the "Accord" method, then the "Modified Accord" methodology. However, no consensus on a permanent solution has yet emerged. In 1998, the Utah Commission made a unilateral decision to reject the previously adopted "Modified Accord" methodology in favor of its preferred Rolled-In methodology. This situation led PacifiCorp to propose a variety of solutions, including the balkanization of the system in the "Structural Realignment Proposal." As this would have lead to the diminution of state regulation vis-à-vis FERC regulation, it was short-lived. After years of negotiation, the Company has now settled on an approach of putting forth its own solution called Protocol, in hopes the various states will adopt it. However, PacifiCorp's proposed solution fails to accomplish a satisfactory resolution of the issues.

Q. IN ITS DIRECT CASE, THE COMPANY HAS PRESENTED ITS "MSP SOLUTION" OR "PROTOCOL" METHODOLOGY. IS THE COMPANY STILL ENDORSING THE PROTOCOL FOR ALL OF ITS STATES?

A. No. On May 21, 2004 the Company filed its Revised Protocol proposal in Oregon in Docket No. UM-1050. It also filed a similar document in Utah around the same time. At a June 16, 2004 presentation to the Oregon PUC, the Company stated that it was very close to an agreement with the Utah parties that would apparently present yet another new Revised Protocol (the "Second Revised Protocol"). On June 28, 2004, PacifiCorp filed a stipulation with the Utah parties and the Second Revised Protocol in the Utah MSP proceeding. On June 29, 2004, PacifiCorp filed the Second Revised Protocol in the Oregon MSP proceeding. Thus, the Company now has or will soon have filings in three states (Washington, Oregon and Utah) with two different versions of the Protocol. According to the Deposition of Andrea Kelly, the Company has no current plan to file any version of Revised Protocol in Washington.[49] Because of this complication, I will call the Protocol filed in Washington the Original Protocol or the Protocol, the first revisions that was filed in Oregon and Utah the Revised Protocol, and the Company's current proposal in Utah and Oregon the Second Revised Protocol.

Q. DOES IT MAKE ANY SENSE FOR THE WASHINGTON COMMISSION TO ADOPT A PROTOCOL THAT THE COMPANY HAS ALREADY ABANDONED IN ITS TWO LARGEST JURISDICTIONS?

A. None at all. First, the Protocol, Revised Protocol and Second Revised Protocol are radically different documents, with substantially different cost impacts on Washington. While Ms. Kelly testified during her deposition that there were only minor revenue requirements impacts of the Revised Protocol compared to the Protocol, this is simply untrue. Comparing PacifiCorp's Revised Protocol and PacifiCorp's Confidential Response to ICNU DR 4.72b shows that the Protocol and Revised Protocol produce revenue requirements for Washington that differ by more than [redacted] (NPV 2005-2018). For 2005 alone, the two methods produce a revenue requirements difference of [redacted] for Washington. If the Revised Protocol were adopted for Washington, it would have a substantial impact on the revenue requirements in this case.

Further, the Revised Protocol has a substantially different treatment of hydro resources, and introduces a new allocation of Qualifying Facilities and Mid-

[49] Exhibit No.__ (RJF-18) at 5-9 (Excerpt of Deposition of Andrea Kelly (June 22, 2004)).

Columbia contracts. The Revised Protocol also does away with the allocation of the Huntington coal plant to Utah and does not feature a "coal opt-out" provision.

Second, if the Washington Commission were to accept the Original Protocol methodology, it would be out of step with the other states. Based on representations made by the Company at the June 16, 2004 workshop before the Oregon Commission, it appears that the latest Utah "Second Revised Protocol" will have substantially different language from the "Revised Protocol." In addition, even if Oregon accepts the Second Revised Protocol rather than the Revised Protocol, the Utah parties have reached a settlement that may contain a side agreement that modifies the revenue requirements impacts of the Second Revised Protocol on that state.[50/] As a result, the Utah methodology will never be the same as the Washington methodology or currently filed Oregon metholodogy. Once again PacifiCorp is proposing differing treatment among the states in an effort to gain agreement.

PacifiCorp also indicated at the Oregon workshop on June 16, 2004 that it intended to file a "Revised Protocol" in Wyoming on or around June 22, 2004. It remains to be seen whether Wyoming will have yet another Protocol document, or whether the filing in that state will conform to what the Company filed in Utah or Oregon. However, it will not be the Protocol filed in Washington if the information given to the Oregon Commission is accurate.

50/ Again, based on the PacifiCorp June 16, 2004 Oregon PUC presentation.

Q. WERE THE OREGON PARTIES ALLOWED THE OPPORTUNITY TO COMMENT ON THE LANGUAGE IN THE UTAH SECOND REVISED PROTOCOL?

A. Only as it related to non-essential issues. There was a process whereby proposed language changes produced by the Utah parties were presented to the Oregon parties. However, adjustments to the most important issues were "off limits" in this rather Byzantine process. To my knowledge, representatives of Washington and other states were not afforded the opportunity to review and comment on the Utah Second Revised Protocol.

Q. IS IT A SIGNIFICANT PROBLEM THAT THE COMPANY IS FILING DIFFERENT PROPOSALS IN DIFFERENT STATES?

A. It is certainly hard to fathom. For the past several years parties from all states met on numerous occasions with the goal of developing a consensus methodology applicable to all states. PacifiCorp has been quite outspoken in its desire to have a unified methodology for all states. However, the Company now has adopted an approach of offering different methods and different "side agreements" for different states. As one who participated in the process over the past several years, I am left to wonder why we bothered with all this effort in the first place. It certainly undermines PacifiCorp's position that it is seeking to develop a single methodology agreeable to and applicable to all jurisdictions.

Q. IS THE PROTOCOL METHODOLOGY BENEFICIAL OR DETRIMENTAL TO WASHINGTON COMPARED TO OTHER METHODS?

A. The Original Protocol method is more costly to Washington than either the Rolled-In or Modified Accord methods. [redacted]

[redacted]

[redacted]

[redacted]

Q. [redacted]

A. [redacted] For this reason, the

51/ Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 4.72b).

Commission should be reluctant to adopt the Original Protocol without major adjustments.

Q. DOES THE PROTOCOL METHOD FAIRLY ALLOCATE THE BENEFITS OF SYSTEM INTEGRATION TO THE STATES?

A. No. Confidential Figure 2, below, shows the allocation of the benefits of system integration to each of the states. This figure was developed by comparing MSP Study 50.5 (Divisional Stand Alone)[52] with the Protocol Study.[53] Under the Original [redacted]

[redacted]

[redacted]

52/ Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 4.51). This was a study in which the system was separated into east and west divisions and dispatched assuming no interconnections.

53/ Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 4.72b).

Q. GIVEN THE PROBLEMS WITH THE FILED PROTOCOL, SHOULD THE WASHINGTON COMMISSION CONSIDER EITHER THE REVISED OR SECOND REVISED PROTOCOLS?

A. No. Neither Revised Protocol has been filed in this case, and there is no record of evidence for analysis of a brand new and substantially changed proposal. At this point, it would be impossible to adopt one of the various Revised Protocol proposals. As Ms. Kelly indicated in her deposition, the Company made a conscious decision to pursue this case with the Original Protocol.[54/]

Q. HOW THEN SHOULD THE COMMISSION PROCEED?

A. The most logical approach would be for the Commission to simply reject the PacifiCorp filing. The lack of a reasonably supported jurisdictional allocation method was one of the reasons the Commission cited for its rejection of PacifiCorp's excess power cost deferral request in Docket No. UE-020417 and one of the reasons the Commission found a new general rate case would be desirable:

> *30* *This brings us to another key problem—the fact that the appropriate basis for inter-jurisdictional allocation of power costs has not been satisfactorily resolved.* Neither PacifiCorp's use of the so-called Modified Accord methodology in reports it files with the Commission, nor the Company's adoption of that methodology for purposes of its filing in Docket No. UE-991832, justifies our simply adopting the methodology for purposes of this proceeding.
>
> *31* We can neither resolve the inter-jurisdictional cost allocation issues on the current record, nor simply ignore these issues and arbitrarily accept PacifiCorp's use of Modified Accord. *We recognize that PacifiCorp has made attempts in its several states to resolve the allocation issue, and is not itself wholly responsible for a failure to reach resolution.* But resolving the allocation issue is

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54/ Exhibit No.__(RJF-18) at 3-9 (Excerpt of Deposition of Andrea Kelly); *see* Exhibit No.__(RJF-7) (PacifiCorp's Response to ICNU DR No. 8.7).

> not the only obstacle. As we have earlier discussed, PacifiCorp failed to meet its burden in other significant respects, which an allocation methodology cannot cure. *The absence of an allocation methodology, however, is one reason, as we discuss later, that a general rate case is desirable.*[55/]

In this case, the Company most certainly is at fault for failing to provide a consistent methodology for all jurisdictions. The absence of a jurisdictional allocation methodology was one of the reasons that the Commission cited for approving an early termination of the rate plan. Because the Company has made a deliberate decision to present Washington with an outdated, unreasonable allocation method that is inconsistent with its other jurisdictions, the Commission would be justified in rejecting this filing.

Alternatively, the Commission could bifurcate this proceeding, and determine the total system revenue requirement and rate of return in this phase. In a subsequent phase, the Commission could require PacifiCorp to file its latest Second Revised Protocol methodology, and the jurisdictional issue could be litigated at that time. New rates could be put into effect <u>after</u> the jurisdictional allocation phase of this proceeding.

Q. ARE THERE OTHER REASONS IT WOULD BE UNWISE FOR THE COMMISSION TO ADOPT PACIFICORP'S FILED ORIGINAL PROTOCOL?

A. Yes. There are a number of technical and policy problems in the PacifiCorp Original Protocol.

55/ <u>Re PacifiCorp</u>, WUTC Docket Nos. UE-020417/UE-991832, Sixth/Eighth Suppl. Order at 14 (July 15, 2003) (emphasis added).

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

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

1. The proposed Hydro Endowment does not provide compensatory benefits to Pacific Division customers. While Pacific Division customers are assigned 100% of the costs of the Western System hydro, they are not allocated all of the benefits of these 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. Further, the members of the standing Committee would be representing states that use different Protocols, and the Standing Committee members may not even operate under the same rules.

These are just a few of the problems.

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

A. This refers to a preferential allocation of PacifiCorp's owned system hydro resources (as distinguished from the Mid-Columbia hydro resources) to customers in the Northwest.[56/] 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 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

56/ For purposes of this testimony I will define the term Hydro Endowment in this manner.

methodology for the hydro preference. However, Modified Accord was criticized on the basis that the Northwest customers obtained the fuel benefit of hydro, but did not pay for the capital costs. Representatives of Oregon and Washington, apparently never considered Modified Accord to be any more than a flawed compromise. Once Modified Accord was abandoned by Utah, support for this compromise in other states evaporated as well. To my knowledge, some form of recognition of Hydro Endowment has always been considered an absolute requirement by the Oregon and Washington parties in the Multi-State Process.

Q. DOES PACIFICORP RECOGNIZE THE HYDRO ENDOWMENT CONCEPT IN ITS PROTOCOL?

A. Yes. The Original Protocol method simply allocates the fixed costs of the hydro facilities to the Northwest. The Original Protocol also allocates the costs of the Huntington coal unit to Utah. The Company contends that the purpose of this is to balance the allocation of hydro to the Northwest.

Q. IS THE COAL ENDOWMENT A SUFFICIENT MEANS OF BALANCING THE COSTS AND BENEFITS OF HYDRO?

A. No. As discussed above, the starting point for a jurisdictional allocation would be the cost of the former PP&L system. In as much as Huntington was a former UP&L plant, assignment of its costs to Utah would be a step in that direction. Because hydro was the former PP&L resource, its costs should be assigned to customers in the Northwest. However, as discussed above, the Original Protocol proposal costs Washington more than even the Rolled-In approach, which does not provide the state with any preferential allocation of hydro. Consequently, we can only infer that the Original Protocol hydro and coal endowment allocations are not compensatory to Washington and fail to assign all of the benefits of these resources to the state.

Q. WHAT ARE THE BENEFITS OF HYDRO THAT SHOULD BE ASSIGNED TO THE NORTHWEST?

A. There are several important benefits. First, there is the energy cost for hydro. Thermal plants require expensive fossil fuels, while hydro has a zero cost fuel. A problem with the Original Protocol methodology is that it assumes the only benefit of hydro to Washington is to avoid the assignment of Huntington fuel costs. In effect, this gives Washington a fuel credit based on the average cost of Huntington fuel. However, other thermal units on the system have higher fuel costs than Huntington, so it is not really equitable to base the fuel credit on the cost of Huntington fuel alone. Consequently, an additional fuel credit should be applied to Washington to compensate for the difference between the Huntington and average thermal plant cost of fuel. In this manner, the hydro plants will be credited with offsetting at least the average cost of fuel on the system.

Second, hydro is also very useful for load following and peak shaving. Hydro plants can meet peak demands and can ramp up quickly to meet minute by minute changes in load. This value is totally ignored in the Protocol. Finally, hydro can provide useful spinning reserve capacity. In the PacifiCorp system, some of the hydro units provide spinning reserves to the eastern division. This is called "dynamic overlay" or simply the "reserve benefit." Protocol does not give credit to the Northwest for any of these benefits either. [redacted]

Exhibit No.__(RJF-19) shows that considering the fuel cost, Dynamic Overlay and load following, benefits of hydro resources amounting to $32.2 million are completely ignored in the Original Protocol.

Cost Shifting

Q. MR. DUVAL TESTIFIES THAT THE DYNAMIC ALLOCATION PROCESS USED IN THE ORIGINAL PROTOCOL METHODOLOGY LIMITS THE IMPACT OF DIFFERENCES IN LOAD GROWTH ACROSS STATES.[58] PLEASE COMMENT.

A. Mr. Duval confirms that this was one of the concerns expressed in the MSP, and he believes that the Rolled-In methodology proposed provides an adequate solution. He does so based on various studies that indicate close to 100% of the cost of a new resource is picked up by the fastest growing state. Thus, he believes "cost shifting" is not a major concern.

However, there are some significant problems with his analysis of this problem. First, the mechanism used in the Original Protocol does not provide any *structural* safeguard against cost shifting. In fact, the results cited by Mr. Duval stem largely from coincidence – i.e., that faster growing states are allocated more of the costs of all system costs (transmission, distribution, overheads, other generators).[59] While this result may occur under current load expectations, fuel costs and overall cost levels, there is nothing to suggest this result will occur

57/ Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 8.11 (PacifiCorp's Response to Oregon PUC Staff DR No. 61 in Oregon PUC Docket No. UM 1050)).

58/ Exhibit No. __(GND-1T) at 16: 12.

59/ Id. at 17: 6-11.

under different conditions. Thus, the Protocol is not necessarily "robust" enough to permanently provide the solution championed by Mr. Duval.

Second, while Mr. Duval contends the cost shifting is small on a percentage basis, the magnitude is substantial in absolute terms. If one assumed that future Utah load growth equaled that of the rest of the system, the amount of the costs shifted to Washington is [redacted] (NPV$ 2005-2018) under the Original Protocol.[60/] This amounts to more than [redacted] of the revenue requirement impact of the Original Protocol compared to the Modified Accord methodology as projected by PacifiCorp.[61/] In other words, without the cost-shifting problem, the Original Protocol would save Washington money compared to Modified Accord. Certainly PacifiCorp would not consider [redacted] to be so inconsequential as to forgo recovery of this amount in Washington.

Third, there is a substantial intergenerational effect that is not apparent in Mr. Duval's studies. The fixed costs of new resources are front-loaded. These costs tend to exceed market levels in the early years. In later years, these costs 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.[62/] Under the Protocol, those benefits will inure to the advantage of the faster growing states in the future instead. As a result, current generations of

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60/ Exhibit No.__(RJF-20C).

61/ *See* Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 4.72b).

62/ This is the reason, that most states place restrictions on the sale of utility property.

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

Finally, Mr. Duval's study does not address many projects that have already been built or are under construction. The Gadsby and West Valley CTs 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. Duval's study does not shed any light on the question of cost shifting vis-à-vis recently constructed resources. Mr. Duval's analysis of cost shifting also failed to include all of the resources that are currently being built. This problem will even be greater when Current Creek, a 525 MW gas fired plant now being built in Utah goes online.

A major drawback with Mr. Duval'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 construction of Current Creek and the Lakeside and the Bonanza purchases. While the studies Mr. Duval references assume a system largely in balance, the reality is that load growth in the east has outstripped supply.

Mr. Duval testifies that the Hybrid method would largely insulate the western division from such costs.[63] Inasmuch as the Protocol was put forth ostensibly as a compromise between the Hybrid and Rolled-In methodologies, it appears that it really fails to address this issue in a satisfactory manner.

[63] Exhibit No.__(GND-1T) at 17: 14.

Consequently, a major defect of the Original Protocol is that it has not developed a structural remedy for the cost shifting problem.

MSP SOLUTION ALTERNATIVES

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

A. Based on the language contained in the merger approval order referenced earlier, the starting point for the Commission is to go back to using the costs of the pre-merger Pacific Power and Light Company. The Commission could determine the amount of the (pre-merger) Pacific Power and Light resources needed to serve Washington, and then develop a methodology to share the benefits of system integration equitably among the states. The "Hybrid" proposal was an attempt to develop and analyze such a methodology. However, as Mr. Duval points out, the Hybrid method is not fully developed at the present time. As a result, the record may not be sufficiently developed regarding the Hybrid proposal to practically apply it in this case. However, I understand that the Staff will be developing an allocation method based on these concepts, so I will not address this issue further.

Q. ASSUMING THE COMMISSION PREFERS TO WORK WITHIN THE PROTOCOL FRAMEWORK, WHAT IS YOUR RECOMMENDATION?

A. If the Commission prefers to use the Original Protocol as its starting point, it must make a number of adjustments to it. Given that PacifiCorp is purposefully following a strategy of using a different jurisdictional allocation for Washington and the rest of the system, the Commission should not be concerned that making additional changes to the Original Protocol will complicate relations with other states.

At a minimum, the most significant drawbacks to the Protocol must be addressed. 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 receive only a small share of the hydro benefits. Next, the problem of cost shifting needs to be addressed in a more systematic manner. Finally, the proposed MSP Standing Committee may not prove to be useful without some adjustments. Unless these problems are addressed, the Protocol is of little practical value to Washington.

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 but receive only some of the benefits. To address this problem, I recommend adding additional benefits to the method to include the full fuel credit (already discussed above), load following and the Dynamic Overlay benefits. Fortunately, it is rather easy to compute these quantities for rate case purposes using the GRID model or other information available in discovery.

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

A. I have computed the load following value by taking the hydro revenue[64/] derived from the Northwest system hydro and deducting from it the revenues from the same amount of energy assuming a totally flat dispatch profile. This difference amounts to approximately $2/MWh. This benefit should be credited against

[64/] 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.

Washington revenue requirements using the same allocation factor as is used to allocate the embedded cost of hydro resources. This analysis was presented in Exhibit No.__(RJF-19).

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

A. I believe this proposal is conservative. Most of the load following generators on the system are gas-fired, and many are fairly new. Gas plants have high fuel 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 costs. 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. [redacted] This amount should also be allocated to Pacific Division states in proportion to the hydro cost.[66]

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

A. The Original Protocol does not address the cost shifting issue. 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,

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[65] Exhibit No.__(RJF-6C) (PacifiCorp's Response to ICNU DR No. 8.11 (PacifiCorp's response to Oregon PUC Staff DR No. 61 in Oregon PUC Docket No. UM 1050)).

[66] *See* Exhibit No.__(RJF-19).

based on the GRID thermal revenue output. This prices the resource at its short-run market price and effectively renders new projects revenue neutral to Washington ratepayers. In the long run PacifiCorp will recover its full cost of new resources, assuming they are economical capacity additions.

Q. IS THERE SUPPORT IN PRIOR COMMISSION DECISIONS FOR SUCH AN APPROACH?

A. Yes. In its Second Supplemental Order in Cause No. U-83-57, the Commission denied a return on the investment in the Colstrip 3 generating plant on the basis that a 40-year contract sale to Black Hills power had to be considered in the context of the Colstrip 3 rate treatment. The Commission found that a contemporaneous power sale to Black Hills Power would provide sufficient revenue over its life to allow the Company to earn a compensatory return on the project. Consequently, it allowed Pacific to retain the revenue from that contract, and removed Colstrip 3 from rate base:

> In January 1984 the company entered into a 40-year contract with Black Hills. Whether that sale is considered a sale of system power or sale of the output from Colstrip, the Commission concludes that the Black Hills contract must be considered in the context of this case. As a result of the contract, the company has reduced the amount of surplus which would otherwise exist. The company has arranged on a long-term basis a sale of power which may ultimately be in the best interest of both the company and the company's Washington ratepayers.
>
> By the terms of this power sales agreement with Black Hills, the company will be made whole over the life of the contract regarding those expenses which the company used in its calculation. Although the initial portion of the contract from 1984 through 1988 involves payment of only 50% of the fixed costs, resulting in some temporary revenue deficiency for the company, the ending years of the contract will reverse this trend. The company was certainly aware of this situation in negotiating the contract with

levelized payments. Allowing rates to reimburse the company for any initial deficiency would result in double recovery to the company over the life of the contract.[67/]

Q. EXPLAIN HOW THIS IS COMPARABLE TO YOUR PROPOSAL.

A. While the Commission found Colstrip used and useful[68/] it valued the output at the price of the Black Hills contract, the revenues from which Pacific was allowed to retain. Prior to FERC Order 888, there was no competitive wholesale power market. However, long term contracts were a de-facto competitive power market even at that time.[69/] Thus, the Commission effectively applied a "market-based" approach to the recovery of Colstrip 3 cost instead of allowing it in rate base. My proposal simply updates that concept for new resources.

Q. HOW WOULD YOU APPLY THIS CONCEPT IN THE CURRENT CASE?

A. I recommend applying the concept to the most recent capacity additions, Gadsby and West Valley and all future resources. These plants are the only resources completed since the last full PacifiCorp rate case (Docket No. UE-991832) and therefore have never been included in rates. In the last case, the Company prepared its filing on the basis that all of the other plants (save Colstrip 3) should be included in rates.

67/ WUTC v. Pac. Power & Light Co., WUTC Cause No. U-83-57, Second Suppl. Order at 9 (June 12, 1984).

68/ Id.

69/ While FERC required that long term contracts be cost based at that time, utilities could circumvent that requirement by selecting a blend of products that produced virtually any desired cost. Thus, if the market was "tight" long-term contracts reflected the high cost of new units. When the market was surplus, contracts might reflect the lower cost of older plants.

Q. HOW DOES THIS METHOD SOLVE THE COST SHIFTING PROBLEM?

A. This method renders the new resources revenue neutral to Washington. 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 short-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. However, the Company should have recognized this was a problem with the lease at the time of execution.

Q. HOW MUCH IS THE ADJUSTMENT RELATED TO THE GADSBY AND WEST VALLEY UNITS?

A. Exhibit No.__(RJF-21) presents the calculation of these adjustments. Applying this adjustment would eliminate the need to apply the adjustment related to the Gadsby rate base and West Valley lease discussed earlier.

Q. AS REGARDS WEST VALLEY, IS IT NECESSARILY THE CASE THAT YOUR DISALLOWANCE WILL HAVE A PERMANENT EFFECT ON PACIFICORP?

A. No. PacifiCorp has recently given notice to Pacific Power Marketing that it will terminate the lease.[70/] If the Company does not rescind its notice, then there will be no permanent disallowance related to West Valley.

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

A. Washington must decide if it is really worthwhile to participate in the process. Having established a fundamentally different jurisdictional allocation

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70/ Exhibit No.__(RJF-22).

methodology than the other states, it should not be inclined to enter into a process of perpetual negotiation.

A serious flaw in the Original Protocol is language that requires a Commissioner to be appointed by each state. However, PacifiCorp's Utah Second Revised Protocol requires only that a Commissioner or a delegate be sent. Were Washington to send a delegate instead of a Commissioner, it would be in violation of the Original Protocol. As a result, the Washington Protocol specifies a different set of rules for participation in the Standing Committee than the Second Revised Protocol.

A further problem is that amendments to either the Protocol and Revised Protocol can be implemented if all states that ratified the original document vote in favor of the amendment. However, Washington will have never ratified the Revised Protocol or Second Revised Protocol, so it will have no real influence in the Standing Committee. To complicate matters further, the Revised Protocol charges the Standing Committee to study certain issues that are not considered in the Original Protocol. As a result, the Standing Committee will have different rules and different expectations for different members. In summary, this is an inconsistent mess!

Q. ARE THERE OTHER PROBLEMS WITH THE STANDING COMMITTEE?

A. Yes. If a state does not send a Commissioner, it will probably lack "clout" compared to other states that do. However, if a state is represented by a Commissioner, that could compromise his or her ability to act as an objective judge of new initiatives that result from the Standing Committee. As a result, I recommend Washington not participate in the Standing Committee, unless all states agree to be represented by a Staff level person and PacifiCorp waives the Protocol requirement that only a Commissioner be sent.

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

A. One of the beneficial features of the Protocol is the coal opt-out provision for Oregon. However, this should not be limited to Oregon. Instead, Washington should also be allowed to opt out of the next coal plant. However, the coal opt-out provision contains a requirement that a state that opts out of the next coal plant should absorb more costs of the next gas unit built. This should be eliminated from the Original Protocol, as it undermines the benefits of the coal opt-out.

In addition, PacifiCorp has made a "side agreement" with the Utah parties that the level of rate impact on that state will not depart from the amount resulting from Rolled-In by more than a specified percentage amount. Washington should insure that it is not required to provide subsidies to support this guarantee or any other rate guarantee to other states such as Idaho. Considering the higher revenue requirement impact of the Original Protocol, this subsidy may well be paid for by Washington in part.

Further, it is possible that the Company will provide inducements to other states as it seeks approval of the Revised Protocol. Washington should insist upon a "Most Favored Nations" clause to insure it receives comparable benefits and does not end up being assigned the costs of such arrangements.

Finally, the Commission should require that if ScottishPower sells PacifiCorp, the Protocol may be revisited at that time.

Q. ARE THERE ANY OTHER CONCERNS WITH THE ORIGINAL PROTOCOL?

A. Yes. I have not detailed all of my concerns because it is not clear where the Company and the Commission will take the issue of different states using different Protocols. If PacifiCorp attempts to supplement its testimony or bring in a revised version of Protocol on Rebuttal, then the Commission should suspend and reset the schedule to allow for full discovery of other issues. As I said earlier, the most straightforward approach is to reject the filing and require PacifiCorp to re-file using a consistent inter-jurisdictional allocation methodology.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit No. ___(RJF-2)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	**Docket No. UE-032065**
vs.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-2)

RANDALL FALKENBERG QUALIFICATIONS

July 2, 2004

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 Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study, economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia 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.

Expert Testimony Appearances
of
Randall J. Falkenberg

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.

Expert Testimony Appearances
of
Randall J. Falkenberg

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.

Expert Testimony Appearances
of
Randall J. Falkenberg

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

Expert Testimony Appearances
of
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
of
Randall J. Falkenberg**

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
of
Randall J. Falkenberg

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.

Exhibit No. ___(RJF-3)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-3)

UTAH PSC DOCKET NO. 03-2035-02

DATA RESPONSE ICNU 5.37D

July 2, 2004

Exhibit No.__(RJF-3)
Data Response ICNU 5.37d
Document filed by PacifiCorp in Support of Utah GRC Stipulation

Attachment A
PacifiCorp
Docket No. 03-2035-02

PacifiCorp Request	127,506,511
ROE @ 10.7% Settlement	(17,679,161)
NPC Settlement	(8,916,417)
Gain on Sale of Aircraft	(309,256)
Adjustment to March 2003 Accruals	(1,137,981)
Accruals Potential Write-Offs	(426,532)
Unbilled Revenues	(8,567,494)
Misc. Expenses	(158,207)
Depreciation Expense on Retired Assets	(537,280)
Incentive Settlement	(3,193,801)
International Assignees	(927,946)
Insurance	(1,061,603)
Tax Advisory Services Settlement	(1,622,779)
Tax Adjustment	(10,311,413)
Remove Expired Amortizations	(6,046,442)
Front Line Write-Off	(1,202,691)
Advertising Expense	(96,591)
Coal Inventory Reserve	(611,558)
Interest and CWC True-up	300,640
Total Adjustments	(62,506,511)
Stipulated Revenue Requirement Increase	65,000,000

= PacifiCorp Original Document

Avg. Utah SE & SG Allocator		39.56%
NPC Settlement at System Level	=(8916417)/.3956	(22,538,972)
Utah NPC Request		522,281,763
Utah Settlment NPC		**499,742,790**

Exhibit No. ___(RJF-4)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-4)

EXCERPT FROM FEB. 8, 2000 NOVA BROADCAST

July 2, 2004

Exhibit No.__(RJF-4)

Excerpt from the Feb 8, 2000 airing of Nova, on PBS

Derived by economists Myron Scholes, Robert Merton, and the late Fischer Black, the Black-Scholes Formula is a way to determine how much a call option is worth at any given time. The economist Zvi Bodie likens the impact of its discovery, which earned Scholes and Merton the 1997 Nobel Prize in Economics, to that of the discovery of the structure of DNA. Both gave birth to new fields of immense practical importance: genetic engineering on the one hand and, on the other, financial engineering. The latter relies on risk-management strategies, such as the use of the Black-Scholes formula, to reduce our vulnerability to the financial insecurity generated by a rapidly changing global economy.

At the very height of their careers, Merton and Scholes were already multi-millionaires. Five years earlier, John Meriwether, the legendary bond trader at Salomon Brothers, had enticed Scholes and Merton to join him and 13 other partners in a new company he was launching, Long Term Capital Management. In 1994, Business Week introduced the public to the "Dream Team" Meriwether had assembled.

Within months they had raised three billion dollars and were ready to start investing across the globe. They set up not on Wall Street but far away from ordinary traders, in Greenwich, Connecticut. From their headquarters they devised one of the most ambitious investment strategies in history. Its success depended on absolute secrecy. Not even their investors were allowed to know what they were doing. Analyzing historical data, they used probability to bet that key prices would move roughly as they had in the past. To protect themselves against unwanted risk, they relied on an insight of the Black-Scholes formula - dynamic hedging. In effect, offsetting risk by taking bets in the opposite direction. Supremely confident, LTCM placed vast sums of money on the markets.

"It was as though the world was behaving exactly the way it had been writ on the blackboard. Long Term Capital thought that they had discovered the path to Nirvana. Here they are doing their day-to-day activities, playing golf in lush Greenwich or attending hedge fund conferences in Bermuda, or raising funds in Cannes. And then slowly and totally unexpectedly, a change in the market dynamics began to become apparent."

In the summer of 1997, across Thailand, property prices plummeted. This sparked a panic that swept through Asia. As banks went bust from Japan to Indonesia, people took to the streets - events so improbable they had never been included in anyone's models.

"Everyone in the marketplace thought the sky was falling, and there was instant reaction. The market broke, then rallied, then broke, then rallied. We didn't know what to believe."

As prices leapt and plunged as never before, the models traders used began to give them strange results, so they relied instead on their instincts. In a time of crisis, cash is king. Traders stopped borrowing and dropped risky investments.

"Models that they were using, not just Black-Scholes models, but other kinds of models, were based on normal behavior in the markets and when the behavior got wild, no models were able to put up with it."

"Although their models told them that they shouldn't expect to lose more than 50 million or so on any given day, they began to lose 100 million and more, day after day after day till finally there was one day, four days after Russia defaulted, when they dropped half a billion dollars, 500 million in a single day."

In Greenwich, LTCM faced bankruptcy, but if the company went down, it would also take with it the total value of the positions it held across the globe - by some accounts $1.25 trillion, the same amount as the annual budget of the US government. The elite of Wall Street would suffer heavy losses. The Federal Reserve Bank called upon the world's top financial regulators to discuss the crisis.

Peter Fisher, a Federal Reserve Regulator said, "What really was the shock for me when we went up to Long Term Capital and the partners gave us an overview of their positions and the risks and the pressures they were under, was the extraordinary scope of the risks that they had taken on, the breadth of the portfolio, and yet how utterly their effort to diversify the portfolio had failed them, how - that this wide set of positions across all markets had all come in, were all behaving the same way. Everything had come up heads.

Math doesn't drive financial markets, people drive financial markets, and people are not predictable. We do not yet have a universal theory of human behavior or human motivation. Given that that's so, we're not likely to have robust models of financial market behavior that will always work, and I think the hubris of the mathematician is to ignore that fact. [emphasis added]"

Exhibit No. ___(RJF-5)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-5)

MORGAN STANLEY CONTRACT VALUATION

REDACTED

July 2, 2004

Redacted
Exhibit No.__(RJF-5)
Page 1 of 1

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY Respondent.	**Docket No. UE-032065**

EXHIBIT NO.__(RJF-6)

PACIFICORP CONFIDENTIAL DATA RESPONSES TO ICNU

REDACTED

July 2, 2004

PacifiCorp Confidential Data Responses to ICNU

Data Response | Page

UE-032065/PacifiCorp
March 23, 2004
ICNU 3rd Set Data Request 3.18

ICNU Data Request 3.18

Please provide all workpapers and bid evaluation documents and electronic spreadsheets related to the comparison of the West Valley lease to other alternatives available to the Company when the decision was made to sign the West Valley lease.

Response to ICNU Data Request 3.18

Bid summary documents are provided on the enclosed CD as Confidential Attachments ICNU 3.18(a)(i-iv). Bid evaluation documents are provided on the enclosed CD as Confidential Attachment ICNU 3.18(b). These documents are confidential and are provided subject to the terms and conditions of the protective order in this proceeding.

Responder: Mark R. Tallman
Witness: Mark R. Tallman

Redacted
Exhibit No.__(RJF-6)
Pages 3 to 9 of 41

ICNU Data Request 4.51

Refer to the Testimony of Mr. Greg Duval:

Has PacifiCorp performed any GRID studies to determine the benefits of integration of the system? In other words, has the Company performed any studies that eliminate the interconnections between the east and west control areas? If so, please provide such studies.

Response to ICNU Data Request 4.51

Yes. The requested studies are provided as Confidential Attachment Response ICNU 4.51. This information is confidential and provided subject to the terms of the protective order applicable to this proceeding.

Responder: Gregory N Duvall
Witness: Gregory N Duvall

Redacted
Exhibit No.__(RJF-6)
Pages 11 to 31 of 41

ICNU Data Request 4.72

Refer to the Testimony of David Taylor:

Please provide workpapers and computer models supporting Exhibit No.__(DLT-5) and Exhibit No.__(DLT-6). Please provide all spreadsheets with all cells and formulae intact and in working order. To the extent that any "add-ins" are required, please provide those along with operating instructions. To the extent that any of the spreadsheets provided are linked to other spreadsheets, please provide all such linked spreadsheets necessary to recreate the entire analysis.

Response to ICNU Data Request 4.72

Please refer to the CD-ROM labeled Confidential Attachment Response to ICNU Data Request No. 4.72. The attachments are confidential and are provided to ICNU subject to the terms of the protective order applicable to this proceeding.

Responder: David L Taylor
Witness: David L Taylor

Redacted
Exhibit No.__(RJF-6)
Pages 33 to 34 of 41

ICNU Data Request 8.11

Please provide complete responses to all of the OPUC Staff's data requests in OPUC Docket No. UM 1050.

Response to ICNU Data Request 8.11

The Company understands, based on discussions with ICNU's attorneys, that this request is made for the purpose of allowing the introduction of responses to Oregon data requests in this proceeding. The Company will not object to the introduction of responses to Oregon MSP data requests in this proceeding.

Responder: Andrea L. Kelly
Witness: Multiple witnesses

OPUC Staff Data Request No. 61

Please provide the annual 2005-2018 dollar values and NPV of the operating reserves provided by the West CA's hydro resources to the East CA.

Response to OPUC Staff Data Request No. 61

Estimates of the value of operating reserves provided by the West control area's hydroelectric resources are provided in Attachment Response OPUC 61b. The approach used to develop these estimates is described in Attachment Response OPUC 61a. Estimates are based on assumptions which are consistent with those used in previous hybrid studies. The information provided in Attachment Response OPUC 61b is confidential and provided subject to the terms of the protective order applicable to this proceeding.

(Attachment(s) Response OPUC 61a and OPUC 61b - Confidential)

OREGON

UM-1050

ATTACHMENT RESPONSE OPUC STAFF No. 61a

MSP Interchange Reserve Adjustment With Credit for PPL Wyoming

Background
The West control area provides 100 Mw of spinning reserves through the dynamic overlay service and 75 Mw of non-spinning reserves to the East control area. This benefits the East control area in that lower reserves can be held on the thermal generating units than what would be otherwise required. The East receives a deduction in the reserve adjustment charge for PPL – Wyoming's portion of the dynamic overlay service before the control area assessment. Pricing for the spinning and non-spinning reserves provided by the West are from PacifiCorp's open access transmission tariff, OV-11, which became effective March 1, 2002.

Basis for Cost in OV-11- The cost of the reserve services in OV-11, noted above, is based on the charges currently in effect with FERC for our full requirements customers (schedule 0V-6.) These customers currently have a demand charge of $7.77/kw month and an energy charge of $17.42 per month. The demand charge is based on the fixed cost of PacifiCorp's Coal and Hydro resources.

Services Provided through OV-11 tariff

- **Spinning Reserve Service** – Spinning reserves are provided immediately in the event of a system contingency. Spinning reserve service is provided by generation units controlled by automatic generation control that are on-line and loaded at less than maximum output. The transmission provider will provide capacity immediately upon an outage until the earlier of restoration of such resource or the end of ten full minutes after the occurrence of such outage. Charges developed for the OV-11 and approved by FERC are as follows:

  Hydro energy delivered = $.266 /MWH (based on $7.77/Kw month x 1000 x 2.5%/ 730 hrs)
  Thermal or other energy delivered = .373 /Mwh (based on $7.77/Kw mth x 1000 x 3.5%/ 730 hrs)
  In case of an outage of a generating resource, energy scheduled is charged at $17.42/Mwh
  (The 2.5% and 3.5% are the the spinning reserve requirements per NERC or 50% of the reserve requirement)

- **Supplemental Reserve Service (75 Mw Non-Spin)** – This service is provided in the case of a system emergency, however it is not available immediately to serve load but rather in a short period of time. This is provided by generating units that are on-line but unloaded, by quick start generation or by interruptible load. This service covers load from 10 minutes after the outage until the earlier of the restoration of the resource or the end of the first full hour immediately following such outage. The price for this service in OV-11is the same as the spinning reserve service.

Formula to calculate Spinning and Non-Spinning Reserve Service

Definitions

Spin Demand = MW capacity for Spinning reserves
Non-spin Demand = MW capacity for Non-spinning reserves.
PDWA = Pacific Division Wyoming Adjustment (1 – Avg. 2000 to 2002 DGP) = .7849
HY = Hour in Year
Spin TED =Spin Thermal Energy delivered
Non-Spin TED =Non-spin Thermal Energy delivered
SRR = 3.5% (i.e. 50% of the Reserve Requirement or spinning portion)
NSRR = 3.5% (i.e. 50% of the Reserve Requirement or non-spinning portion)
OV11 Price = $.373/Mwh

Formula

Spin TED = (Spin Demand * (PDWA) * HY) / SRR
Non-spin TED = (Non-Spin demand * (PDWA) * HY) / NSRR

Spin Reserve Charge $ =Spin TED * OV11 Price
Non-spinning reserves Charge $ =Non-spin TED * OV11 Price

Example of Annual Charge for Interchange Spinning and Non-Spinning Reserve Services

- 100 Mw Spinning Res. = $7,327,100 ((100 Mw (1-.215149) x 8760)/.035 x $.373MWh)
- 75 Mw Non Spinning Res. = $5,495,325 ((75 Mw (1-.215149) x 8760)/.035 x $.373 MWh)

Total charge $12,822,425

East control would incur a $12.8 million increase in revenue requirement while the West would receive $12.8 million of benefits from providing the spin and non-spin services under the current OV11 rates. This
includes an adjustment for Wyoming bringing a benefit of $3.5 million for reserves. Without the Wyoming adjustment the annual charge would be $16.3 million.

OREGON

UM-1050

ATTACHMENT RESPONSE OPUC STAFF No. 61b

Redacted
Exhibit No.__(RJF-6)
Page 41 of 41

Exhibit No. ___(RJF-7)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-7)

PACIFICORP NON-CONFIDENTIAL DATA RESPONSES TO ICNU

July 2, 2004

PacifiCorp Non-Confidential Data Responses to ICNU

ICNU Data Request 1.5

For the P4 Production, please provide the following:

a. A copy of the contract (in pdf or other electronic format, if available).
b. An explanation as to how the costs and benefits of the contract are reflected in the GRID model, and in the test year (to the extent not reflected in GRID).
c. An explanation of the reasons why PacifiCorp entered into the contract.
d. Any evidence that PacifiCorp cares to present demonstrating the prudence of the contract.
e. Any workpapers used to develop the GRID input assumptions related to the contract.
f. The start and stop dates for the contract.
g. Any economic analysis, including but not limited to options value studies, used to evaluate the contract prior to signing.
h. Please provide a calculation and supporting workpapers showing the benefits from the contract reflected in the GRID study, or elsewhere in the test year.

Response to ICNU Data Request 1.5

P4 Production, L.L.C. is the name of the facility at Soda Springs, Idaho. It is a joint venture with Monsanto and Solutia. The contract is with Monsanto and is an implementation of Idaho Public Utilities Commission Order No. 29157.

a. IPUC Order No. 29157 is provided as Attachment ICNU 1.5 a1 on the enclosed CD. The Monsanto contract is provided as Attachment ICNU 1.5 a2 on the enclosed CD.
b. The GRID inputs were based on the contract.
The contract has several parts. The parts that relate to Net Power Cost (versus retail load) are Curtailment, Operating Reserve and System Integrity.

- Curtailment is modeled as an energy limited archetype contract. GRID curtails the 500 higher priced hours during the year.
- Operating Reserve is modeled as a contract reserve archetype contract. GRID will use this resource in lieu of backing down a thermal unit.
- System Integrity is modeled as a no-energy archetype contract. Under normalized conditions, the Company does not expect a qualifying event that would allow us to exercise this option. However, customers are protected from such an event much like property insurance protects against property losses. So even if there is not a payment, customers still received the benefit of being protected.

c. The contract is an implementation of Idaho Public Utilities Commission Order No. 29157.The P4 operating reserve agreement provides a minimum of 46MW of contingency non-spin operating reserves in the Eastern Control area. Monsanto is able to meet all the WECC criteria for non-spin operating reserves and therefore the contract can be utilized for reserves versus holding reserves on our own generating plants.
d. Please see the Company's response to parts b, c, and g.
e. The GRID inputs are taken from the Commission Order. Special work papers were not needed for the model inputs.
f. The start and stop dates are January 1, 2003 to December 31, 2006.
g. The requested information is provided on the enclosed CD as Attachment ICNU 1.5 g.
h. The Company did not prepare a separate GRID NPC study to identify the benefits associated with the contract during the forecast period. Please refer to the Company's response to ICNU Data Request 1.5g.

Responder: Mark Widmer
Witness: Mark Widmer

ICNU Data Request 1.25

Has PacifiCorp made any adjustments to the test year to reflect the imputation of higher revenues for the WAPA transmission contract, as it has typically done in recent Utah jurisdiction cases? If not, please explain why not. If it did, please provide details and amounts.

Response to ICNU Data Request 1.25

PacifiCorp has not imputed revenue for the WAPA transmission contract nor does the Company believe it is appropriate to do so. The WAPA contract was entered into in 1962. Many of the assets supporting the wheel were in service before the contract was signed. Lines relied upon to wheel for WAPA are largely depreciated. Revenue from the WAPA contract exceeds the cost to serve WAPA loads. Thus, revenue imputation is not appropriate.

Responder: Ted Weston
Witness: Ted Weston

ICNU Data Request 1.26

If the answer to ICNU Data Request 1.25 above is no, please provide a calculation showing the level of revenues produced by the WAPA contract and the amount that would have been produced using the formula used by the Utah Commission.

Response to ICNU Data Request 1.26

Actual WAPA KWh: Peak KWh: 3,773,126
Billed Revenues Contract: (2436): $2,212,529
Imputed Revenues using current FERC Tariff Price:

Peak KWh	Monthly Price	Annual Price	Imputed Revenues
3,773,126	$2.0250	$24.30	$7,640,580

Discounted Revenue on the WAPA contract (2436 only) for the period ended March 03: $5,428,051(Total Company).

Responder: Ted Weston
Witness: Ted Weston

ICNU Data Request 1.39

Is PacifiCorp aware of any mistakes in the GRID power cost study used in the test year? If so, please indicate the nature of the mistake, and the amount by which the Company proposes to change its test year revenue requirements due to the mistake.

Response to ICNU Data Request 1.39

The Company is aware of nine mistakes in its filed power cost study that should be corrected.

1. The weighting applied to the hydro data series for each year is not consistent with the hydro data. This case is filed using a 40-year hydro data series, but the weighting still reflects the Company's use of a 50-year hydro data series. This correction resulted in a decrease to power costs of $1.1 million. The corrected study is provided as Attachment ICNU 1.39a on the enclosed CD.

2. The inability to carry operating reserves on Swift 1 as a result of the outage on Cowlitz Swift 2 project was inadvertently not included in the Company's filing. This correction resulted in an increase to power costs of $3.6 million. The corrected study is provided as Attachment ICNU 1.39b on the enclosed CD.

3. The reserve capacity on the expired Colockum contract was inadvertently not removed when the contract expired. This correction resulted in an increase to power costs of $0.5 million. The corrected study is provided as Attachment ICNU 1.39c on the enclosed CD.

4. The Company's licensing requirements concerning the rate of change of the stream level below Merwin was not properly reflected in GRID. This correction resulted in an increase to power costs of $1.7 million. The corrected study is provided as Attachment ICNU 1.39d on the enclosed CD.

5. Forecast payments associated with the Kennecott Generation Incentive Contract, rather than actual payments for the test period, were inadvertently included in the Company's filing. This correction resulted in an increase of power costs by $1.0 million. The corrected study is provided as Attachment ICNU 1.39e on the enclosed CD.

6. The heat rates associated with the thermal plant dispatch logic did not match the heat rate curve used in the Company's filing. This correction

resulted in an increase of power costs by $0.2 million. The corrected study is provided as Attachment ICNU 1.39f on the enclosed CD.

7. The heat rate curve used for the West Valley CTs was based on manufacturer's estimates. These estimates have been found to be higher than what actual performance has shown. A revised estimate of the West Valley CT heat rate, based on one year of actual data resulted in a decrease of power costs by $1.7 million. The corrected study is provided as Attachment ICNU 1.39g on the enclosed CD.

8. The "shape to load" attributes for the BPA Peaking Contract were entered incorrectly. This correction resulted in a decrease of power costs by $1.2 million. The corrected study is provided as Attachment ICNU 1.39h on the enclosed CD.

9. The Short Term Firm data included Redding Exchange energy that was already accounted for in the long term transactions. Excluding these transactions from the data resulted in a decrease of power costs by $1.5 million. The corrected study is provided as Attachment ICNU 1.39i on the enclosed CD.

When corrected, net power costs increase by $8.8 million on a Total Company basis. The study with all the changes is provided as Attachment ICNU 1.39j on the enclosed CD. The Company is not proposing to change the level of rate relief requested in this filing as a result of these corrections. These corrections will be reflected in a revised revenue requirement during the rebuttal phase of the case, subject to the limitation in the overall rate request established by the Company's initial filing.

Responder: Mark Widmer
Witness: Mark Widmer

ICNU Data Request 1.70

Please explain why PacifiCorp did not pro-form out the Hunter outage (November 2000 to May 2001) in its NPC study as it did in the recent Oregon and Utah rate cases.

Response to ICNU Data Request 1.70

The Company did not recover Hunter 1 replacement power costs in Washington as the Company did in Oregon and Utah. The Company used the same treatment as it did in Wyoming, which also did not provide recovery of Hunter 1 replacement power costs.

Responder: Mark Widmer
Witness: Mark Widmer

ICNU Data Request 1.71

Please explain why there were a number of main transformer problems at Hunter in the period 2000 to 2002, and list any steps taken to correct this problem.

Response to ICNU Data Request 1.71

Hunter Unit 1

November 10, 2000 - Unit 1 experienced a low oil flow alarm on 1-1 main transformer and the unit was restricted until the cause of the alarm was determined. The cause was determined to be a faulty contact which was repaired and the unit returned to normal service.

October 22, 2001 - Hunter 1-1 Main Transformer failed during a unit startup after the unit was off line for Forced Draft fan problems. The transformer failure was thought to be caused by a combination of faulty oil level indication, a vacuum condition due to oil shrinkage and weakness in insulation levels. A spare transformer was not available, so the isophase bus was configured to allow the unit to be started up on October 27 and operated at half load with the 1-2 transformer in service. A transformer which was previously removed from the 2-2 position due to gassing was then given a high priority for evaluation and repair. General Electric was contracted to perform acoustical partial discharge testing to determine the cause of the gassing. No problems were found with the windings, but during testing one of the high voltage bushings failed and one of the oil pumps was discovered to have a heating problem. These two items were replaced and after additional testing, the transformer was installed during an outage on December 21 – 23. A Hydran brand instrument which continuously monitors the amount of dissolved hydrogen in the oil was installed at this time. The transformer operated without gassing from this point forward.

August 22, 2002 – The 1-1 transformer began leaking oil from an atmospheric vent on the conservator tank and unit load was reduced and then the unit was taken off line to determine the cause of the leak. The leak was determined to be a faulty bladder in the conservator tank and temporary repairs were made and the unit brought back on line. A replacement bladder was obtained and the unit was taken off line on September 20 to replace the bladder. The bladder was also replaced on 1-2 transformer while the unit was off line.

Hunter Unit 2

August 24, 2001 - Samples taken for a preventative maintenance Dissolved Gas Analysis (DGA) on the Hunter 2-2 Main Transformer indicated very high levels of combustible gas building in the transformer. Company experts were consulted and additional DGA samples were taken at different loads on the transformer. The temperature indications were normal and the cooling systems were operating normally. The combustible gas level remained high and the decision was made to remove the unit from service and troubleshoot the cause of the gassing on August 25. The transformer was visually inspected and underwent a series of electrical tests. No readily apparent mechanism for the source of the gassing was found and the decision was made to install a spare transformer in place of the existing transformer. The isophase bus was configured for single transformer operation and the unit brought up to half load on August 30. The gassing transformer was removed and the spare transformer was installed. The unit was brought off line to connect the new transformer on September 8 and returned to service on September 10. On September 14 unit load was reduced to investigate a high oil temperature alarm on the new transformer. The cause was determined to be an incorrect current transformer (CT) installed at the factory. The proper CT was installed during the next unit overhaul. A Serveron brand online continuous DGA monitor for combustible gasses was installed on this transformer during installation.

November 10, 2001 – A cooling fan on 2-1 transformer failed and caused the power supply to the transformer to trip. The unit load was quickly reduced while crews isolated the fan and restored power back to the remaining cooling equipment.

Summary
The main cause of the transformer problems is the age and condition of the windings and/or auxiliary equipment. The DGA analysis has been changed to a quarterly frequency and plans are to install online DGA analyzers during the next overhaul cycle on all Hunter Generator Step Up Transformers (GSU). The transformer maintenance procedures have been modified to include external verification of the liquid oil gauges. New Qualitrol digital fan and pump controllers have been added to all transformers to assure reliable operation of the cooling circuits. The fans have been electrically tested and replacement fan stocking levels have been increased. The fire protection deluge systems have been upgraded with new valves and controls.

A Generation Transformer Best Practices task force has been implemented to address transformer issues across the fleet and will make recommendations on predictive/preventative and repair maintenance practices and procedures, instrument and monitoring practices, standards and training for the Company.

Responder: Barry Cunningham
Witness: Barry Cunningham

ICNU Data Request 1.73

Please provide a summary of to-date actual power costs for the Pro-Forma period. Note this is a continuing request and should be updated each month as data becomes available.

Response to ICNU Data Request 1.73

The requested information was provided in response to ICNU Data Request 1.44.

Responder: Mark Widmer
Witness: Mark Widmer

ICNU Data Request 3.22

Reference PacifiCorp's Response to ICNU 1.71. Please identify the costs included in the test year related to steps taken to rectify the transformer problems at Hunter.

Response to ICNU Data Request 3.22

Of the transformer issues identified in ICNU 1.71, the following are PacifiCorp's share charges incurred during FY 2003:

O&M
Work order 25294538 to repair the unit 1 conservator bladders had $184,169 in charges incurred during the test year.

Capital
Project SHTR/2002/C/063 incurred $23,487, the FY 2003 portion of the project to remove and install the 2-2 main transformer.

Project SHTR/2002/C/076 incurred $1,413,735 due to delivery of spare transformer for unit 1&2 which replaced 1-1 transformer.

Project SHTR/2003/C/038 incurred $18,967 for installation of Qualitrol digital fan and pump controllers on unit 1.

Project SHTR/2003/C/039 incurred $21,693 for installation of Qualitrol digital fan and pump controllers on unit 2.

Project SHTR/2003/C/040 incurred $10,030 for installation of Qualitrol digital fan and pump controllers on unit 3.

Responder: Mark T. Widmer
Witness: Mark T. Widmer

UE-032065/PacifiCorp
March 23, 2004
ICNU 3rd Set Data Request 3.23

ICNU Data Request 3.23

Reference PacifiCorp's Response to ICNU 1.72. Please identify the costs included in the test year related to steps taken to rectify the turbine problems at Blundell.

Response to ICNU Data Request 3.23

No costs were incurred in the test year related to steps taken to rectify the turbine problems at Blundell.

Responder: Mark T. Widmer
Witness: Mark T. Widmer

ICNU Data Request 5.29

Reference ICNU Data Request No. 3.21. Does the company intend that the answer should say "However, the lack of hourly temperature modeling is NOT a material deficiency"? If so, please provide a revision to ICNU Data Request No. 3.21.

Response to ICNU Data Request 5.29

Yes. The response should say, "However, the lack of hourly temperature modeling is NOT a material deficiency." Please see the Company's revision to ICNU Data Request 3.21 below.

Revised Response to ICNU Data Request 3.21

At this time, the Company does not have hourly temperature versus capacity tables based on historical values. The Company has a project in place to review the GRID capability values for units impacted by ambient conditions. When the project is completed, "temperature versus capacity tables" should be available.

The requestor can produce the tables from the generator log previously provided and from temperatures available from the National Weather Service web site.

GRID does not model hourly adjustments to unit capacity for changes in ambient conditions. GRID uses monthly normal high temperatures. However, the lack of hourly temperature modeling is not a material deficiency. The GRID back cast, which was within .1% of actual net power cost results, demonstrates that the current configuration of GRID appropriately models the system and net power costs. Therefore, it does not appear that hourly modeling of capacity based on ambient conditions would have a material impact on results.

The paragraphs below describe how the seasonal capability pattern was developed for the units whose capability is significantly impacted by hourly temperature:

Utah Peaking Units

Prior to the installation of the Utah peaking units, a table of expected average capacity of each month was developed based on manufacturer's data. Provided on the enclosed CD, Attachment ICNU 3.21A is the workbook that was used to develop the table. Once a significant amount of data points from the operational history becomes available, the Company will develop a normalized table for the units.

ICNU Data Request 5.30

Reference ICNU Data Request No. 3.21. Please provide all documentation provided by plant personnel supporting the difference in summer and non-summer availability for Wyodak.

Response to ICNU Data Request 5.30

The information requested does not exist. As stated in ICNU Data Request No. 3.21, the values are based on the experience and judgment of plant personnel.

Responder: Mark T. Widmer
Witness: Mark T. Widmer

ICNU Data Request 5.33

Reference ICNU Data Request No. 3.23. The response indicates that no costs were incurred in the test year, related to the steps taken to rectify the problem. Please identify and quantify the total amount of costs related to correcting this problem irrespective of whether it was incurred in the test year or not. Please provide information concerning the accounting treatment of these costs.

Response to ICNU Data Request 5.33

Capital costs (workorder # 20004201) incurred during FY 2000 and 2001 for Steam path replacement were $3,184,771.

Removal costs (workorder # 20004202) incurred were $56,180. Salvage was $5,000.

In April FY 2003 the Company contracted with Turbocare to perform a video (borescope) inspection @ $6,844.69.

In October FY 2004 the Company contracted with Turbocare to perform a video (borescope) inspection @ $4,985.

Responder: Mark T. Widmer
Witness: Mark T. Widmer

UE-032065/PacifiCorp
April 9, 2004
ICNU 5th Set Data Request 5.42

ICNU Data Request 5.42

Please explain why the GRID power cost study shows PacifiCorp purchasing $3.007 million dollars of emergency energy on Sunday, February 29, 2004 (during LLH) in the Mid Columbia bubble. (See the GRID hourly imbalance export for that day.)

Response to ICNU Data Request 5.42

The market cap data series inadvertently did not include February 29, 2004. With no values entered for this day, GRID placed a Market Cap of zero on the Mid Columbia Transmission Area. With a load requirement in Mid Columbia, on that day, GRID had to make Emergency Purchases from the Transmission Area to meet this load requirement.

The emergency purchase price for the Mid Columbia Transmission Area is set at $10,000 because Mid Columbia is a liquid market, which entails that GRID has the ability to purchase from the market at any time, as long as the market is not closed.

Because the markets on February 29th were in a sense, closed, GRID could not purchase energy from the market. GRID had to use the Transmission Area to purchase emergency energy where the price was set at $10,000.

Correcting this error would reduce Net Power Cost by $2.9 million on a Total Company basis.

Responder: Mark T. Widmer
Witness: Mark T. Widmer

ICNU Data Request 8.7

If the answer to ICNU Data Request 8.5 is no, why is the Company not planning on filing a revised or more current version of Protocol?

Response to ICNU Data Request 8.7

PacifiCorp objects to this request to the extent that the response would require the Company to divulge privileged and confidential attorney-client communications. Without waiving the foregoing, PacifiCorp responds as follows:

PacifiCorp is not currently aware of an opportunity for it to make an additional filing in this proceeding in advance of the filing of testimony by Commission Staff and intervenors that would be consistent with the Commission's procedural rules and the Prehearing Conference Order that has been entered in this proceeding. However, assuming consensus is reached with parties in other states regarding a revised Protocol, PacifiCorp would be prepared to file such a revised Protocol in a supplemental filing in these proceedings if: a) Commission Staff and intervenors are agreeable to such a filing and b) such a filing would not delay the issuance of a final order in these proceedings.

Although the Company has not yet filed the Revised Protocol in Washington, the effect of the Revised Protocol on revenue requirement and on the proposed rate increase in this case have been provided through discovery. In response to WUTC Staff 222 and ICNU 8.16, PacifiCorp has provided a recast of the revenue requirement in this case based on the Revised Protocol.

Responder: Jamie Van Nostrand
Witness: None

Exhibit No. ___(RJF-8)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	**Docket No. UE-032065**
vs.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-8)

STRATEGIC HEDGES PRESENTATION

REDACTED

July 2, 2004

Redacted
Exhibit No.__(RJF-8)
Pages 1 to 6 of 6

Exhibit No. ___(RJF-9)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	**Docket No. UE-032065**
vs.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-9)

BRIDGER/GADSBY COMPARISON

July 2, 2004

Exhibit No.__(RJF-9)
Anomalous Dispatch of CTs and Coal Units
PacifiCorp GRID Study

Hour		12/31/2003 Bridger 3	Gad CT 1		11/28/2003 Bridger 3	Gad CT 1		10/7/2003 Bridger 3	Gad CT 1		1/22/2004 Bridger 3	Gad CT 1		5/26/2003 Bridger 3	Gad CT 1
0	LLH	181	0	LLH	325	0	LLH	325	0	LLH	325	0	LLH	319	0
1	LLH	231	0	LLH	216	0	LLH	143	0	LLH	261	0	LLH	250	0
2	LLH	169	0	LLH	226	0	LLH	140	0	LLH	253	0	LLH	179	0
3	LLH	164	0	LLH	215	0	LLH	142	0	LLH	249	0	LLH	158	0
4	LLH	140	0	LLH	228	0	LLH	160	0	LLH	303	0	LLH	171	0
5	LLH	140	0	LLH	147	0	LLH	267	0	LLH	260	0	LLH	150	0
6	HLH	140	20	HLH	216	0	HLH	325	0	HLH	325	20	LLH	325	0
7	HLH	143	20	HLH	287	20	HLH	325	20	HLH	325	20	LLH	325	0
8	HLH	143	20	HLH	210	20	HLH	320	26	HLH	303	20	LLH	325	0
9	HLH	140	20	HLH	209	20	HLH	309	26	HLH	254	20	LLH	325	0
10	HLH	140	20	HLH	164	20	HLH	294	37	HLH	184	20	LLH	140	0
11	HLH	140	20	HLH	149	20	HLH	246	37	HLH	158	20	LLH	140	0
12	HLH	140	20	HLH	142	20	HLH	250	37	HLH	151	20	LLH	140	0
13	HLH	140	20	HLH	216	20	HLH	277	37	HLH	154	20	LLH	140	0
14	HLH	169	20	HLH	201	20	HLH	235	37	HLH	305	20	LLH	186	0
15	HLH	185	20	HLH	325	20	HLH	325	37	HLH	309	20	LLH	221	20
16	HLH	140	20	HLH	167	20	HLH	325	37	HLH	325	20	LLH	324	20
17	HLH	143	20	HLH	266	20	HLH	325	37	HLH	225	20	LLH	305	20
18	HLH	144	20	HLH	261	20	HLH	295	20	HLH	253	20	LLH	325	20
19	HLH	142	20	HLH	208	20	HLH	316	37	HLH	198	20	LLH	325	0
20	HLH	140	20	HLH	176	20	HLH	284	25	HLH	166	20	LLH	325	0
21	HLH	172	20	HLH	259	20	HLH	325	20	HLH	290	20	LLH	325	0
22	LLH	205	0	LLH	297	20	LLH	325	20	LLH	325	0	LLH	325	0
23	LLH	179	0	LLH	305	0	LLH	325	0	LLH	325	0	LLH	325	0

Figure 1: HDN-1 Capacity Duration Curve

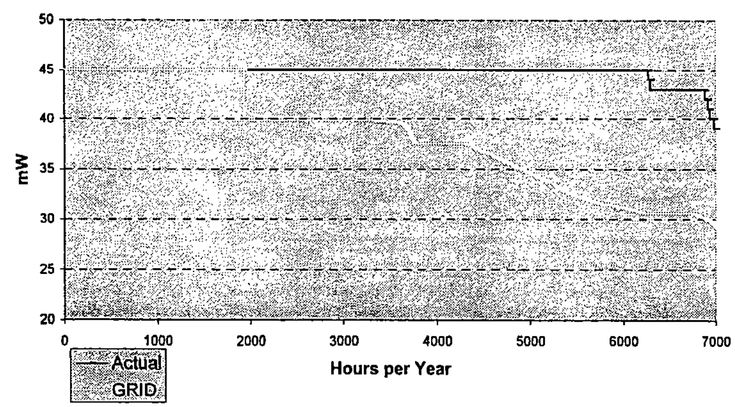

Exhibit No. ___(RJF-10)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	**Docket No. UE-032065**
vs.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-10)

FOUR YEAR HISTORICAL GENERATION LEVELS

July 2, 2004

Exhibit No.__(RJF-10)
Four Year Historical Generation Levels

Year	
1999	44,776,202
2000	45,632,205
2001	43,987,867
2002	43,631,399
Avg.	44,506,918
Adjustments	
Spinnng Reserve Adj.	328,500
Colstrip 3	-460,562
Hunter Outage	380,977
Other Outages	235,000
Centralia Replacement	252,192
1999 Market Price Adj.	46,360
Total Adjustments	782,467
Adjusted Generation	45,289,385
PacifiCorp GRID Coal mWh	44,382,407
ICNU Final Run mWh	45,269,008 **(Run W1740)**

Exhibit No. ___(RJF-11)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
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PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-11)

COMPARISON OF OUTAGE RATES

July 2, 2004

Exhibit No.__(RJF-11)
Comparison of Outage Rates UE-991832 and UE-032065

	===========2003 Rate Case=========				1999 Case	=Avg Capacity on Outage=	
	Unit ID	Current Rated Capacity	Outage Rate	PacifiCorp Share	Outage Rate	2003 Case	1999 Case
1	BLN-1	23	12.19%	100.0%	14.43%	2.8	3.3
2	CHO-4	380	10.24%	100.0%	6.67%	38.9	25.3
3	COL-3	740	17.57%	10.0%	7.17%	130.0	53.1
4	COL-4	740	10.68%	10.0%	9.57%	79.1	70.8
5	CRB-1	70	5.41%	100.0%	7.51%	3.8	5.2
6	CRB-2	105	6.37%	100.0%	6.33%	6.7	6.6
7	CRG-1	428	4.16%	19.3%	2.40%	17.8	10.3
8	CRG-2	428	4.08%	19.3%	4.23%	17.5	18.1
9	DJ-1	106	4.24%	100.0%	4.93%	4.5	5.2
10	DJ-2	106	4.22%	100.0%	4.31%	4.5	4.6
11	DJ-3	223	13.84%	100.0%	13.62%	30.9	30.4
12	DJ-4	330	14.73%	100.0%	9.66%	48.6	31.9
13	GAD-1	60	0.49%	100.0%	0.40%	0.3	0.2
14	GAD-2	75	6.61%	100.0%	1.62%	5.0	1.2
15	GAD-3	100	3.78%	100.0%	2.77%	3.8	2.8
16	HDN-1	184	13.27%	24.5%	6.43%	24.4	11.8
17	HDN-2	262	3.32%	12.6%	6.98%	8.7	18.3
18	HTG-1	440	10.58%	100.0%	10.22%	46.5	45.0
19	HTG-2	455	10.85%	100.0%	9.47%	49.4	43.1
20	HTR-1	427	12.27%	93.8%	8.97%	52.4	38.3
21	HTR-2	430	10.65%	60.3%	6.23%	45.8	26.8
22	HTR-3	460	10.19%	100.0%	6.35%	46.9	29.2
23	JB-1	530	9.20%	66.7%	7.35%	48.8	39.0
24	JB-2	530	8.38%	66.7%	6.57%	44.4	34.8
25	JB-3	530	8.54%	66.7%	8.93%	45.2	47.3
26	JB-4	526	12.09%	66.7%	8.06%	63.6	42.4
27	NTN-1	160	4.87%	100.0%	1.79%	7.8	2.9
28	NTN-2	210	6.76%	100.0%	3.90%	14.2	8.2
29	NTN-3	330	9.69%	100.0%	10.96%	32.0	36.2
30	WYO-1	335	3.42%	80.0%	5.05%	11.5	16.9

Average	8.42%	6.76%	935.5	709.2
Change	25%		32%	
Units with Increasing outage rates		21		
Total Number of Units		30		
Percent		70%		

Increase in Outage Capacity - mW	226.3
Savings per kW of added coal generation	$139,914
Test Year Cost	$31,664,245

Exhibit No. ___(RJF-12)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-12)

LIST OF OUTAGES

July 2, 2004

Exhibit No.__(RJF-12)
List of Outages That Should be Removed From
Normalized Net Power Cost Study

Event(s)	Unit	Start Date	End Date	Duration	Lost Energy	Cause
1	HTR-1	Nov-00	May-01	3780	1625500	Generator
2	GAD, WV	Jun-02	Mar-03	10660	426412	Various
3	JB-4	Jun-00	Jul-00	316	164,060	Main Trans
4	HTR-1,2	Nov-00	Sep-02	1967	414230	Main Trans
5	BLN-1	Oct-98	Jun-01	15964	63084	Turbine
6	HTR-3	Nov-99	Nov-99	140.90	64,814.00	Vibration
7	DJ-3	Sep-99	Oct-99	1,030	236,850	Generator
8	HDN-1	Jul-00	Oct-00	1,815	333,960	Vibration
9	COL-4	Jun-01	Jul-01	389	287,638	Generator

Exhibit No. ___(RJF-13)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	**Docket No. UE-032065**
vs.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-13)

WYOMING PSE DOCKET NO. 20000-ER-02-184

EXCERPT OF TRANSCRIPT OF HEARING PROCEEDINGS

VOLUME IV

July 2, 2004

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF WYOMING

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING, CONSISTING OF A GENERAL RATE INCREASE OF APPROXIMATELY $30.7 MILLION PER YEAR, A THREE-YEAR RATE SURCHARGE FOR PREVIOUS POWER COSTS TO RECOVER $60.3 MILLION, AND AN ADDITIONAL THREE-YEAR RATE SURCHARGE TO RECOVER POWER COSTS OF $30.705 MILLION RELATED TO THE HUNTER NO. 1 GENERATING UNIT

Docket No.
20000-ER-02-184
(Record No. 7475)

TRANSCRIPT OF HEARING PROCEEDINGS
VOLUME IV
January 13, 2003

PURSUANT TO NOTICE duly given to all parties in interest, this matter came on for hearing on the 13th day of January, 2003, at the hour of 10:00 a.m., in the Hearing Room at 2515 Warren Avenue, Suite 300, Cheyenne, Wyoming, before the Public Service Commission, Chairman Steve Ellenbecker presiding, with Deputy Chairman Steve Furtney and Commissioner Kristin Lee also in attendance. Also present were Stephen G. Oxley, Secretary and Chief Counsel of the Commission, Christopher Petrie, Counsel of the Commission, and David Mosier, technical advisor of the Commission.

A P P E A R A N C E S

For the Applicant PacifiCorp:

MR. BRENT R. KUNZ
Attorney at Law
2515 Warren Avenue, Suite 500
Cheyenne, Wyoming 82001

MR. EDWARD HUNTER
MS. KATHERINE A. McDOWELL
MS. JENNIFER E. HORAN
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For the Intervenor WIEC:

MR. ROBERT M. POMEROY, JR.
MR. THOR NELSON
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For the City of Evanston and AARP:

MR. DALE W. COTTAM
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Cheyenne, Wyoming 82001

For the Consumer Advocate Staff:

MR. DOUGLAS J. MOENCH
MR. IVAN WILLIAMS
MR. DAVID J. LUCERO
Staff Attorneys
Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne, Wyoming 82002

INDEX AT END OF VOLUME

only consultant that made that allegation was Mr. Nippes early in the process and that was fully discussed in another state's proceeding, and the conclusion there was it would not happen. And the rest the consultants share that same opinion.

DEPUTY CHAIRMAN FURTNEY: Thank you. That's all I have. Mr. Chairman.

CHAIRMAN ELLENBECKER: Commissioner Lee.

COMMISSIONER LEE: Thank you, Mr. Chairman

EXAMINATION BY THE COMMISSION

Q. (BY COMMISSIONER LEE) Mr. Cunningham, in your opinion, when you look at this whole case, the whole big universe, if PacifiCorp can't pinpoint the cause of this failure, should the company pay for it or should the ratepayer pay for it, if the company can't point the root cause, just in your opinion?

A. Well, I'm sure my answer is predictable here, but I don't think this is the kind of risk that you expect us to take to the shareholders.

COMMISSIONER LEE: Okay. Thank you. Thank you, Mr. Chairman.

EXAMINATION BY THE COMMISSION

Q. (BY CHAIRMAN ELLENBECKER) Mr. Cunningham, have you ever been involved in a situation with PacifiCorp where there was an issue surrounding maintenance or testing or equipment integrity for a generation facility where the company did an examination and acknowledged either human or equipment or testing failure of its own making as being the fault?

A. Yes, sir.

Q. Can you illustrate one of those?

A. The most recent one that comes to mind was a main transformer failure at the Jim Bridger Plant, and it would have been in the summer, I believe, of 2000. It was on, I believe, Jim Bridger 4 if I've got the units straight.

The circumstances surrounding that was the unit was in overhaul, a normal overhaul and the main transformer had normal routine maintenance on it, and somewhere the traveling apparatus crew that came into the plant to work on the crew worked on it under a clearance. We have safety clearances for people working on the equipment. And rather than have the operating personnel lock out the power to the cooling equipment on the fan, they did it themselves, and on start-up, the return to service when the tags were recovered, nobody knew that the cooling equipment was still off.

So when the unit was started, it came to load and the transformer temperature got high. The operators observed it at that point, but it was late into it. They dropped the load, got it under control and about a week later the transformer failed in service, and we knew that it was because it had been overheated.

We had a spare transformer. It took us about two weeks, 13 days, as I recall, to replace it. This was again during the high-price power period, too.

Q. And what are the regulatory implications of that situation, if you know?

A. I don't. They become part of our net power cost calculation and there was no -- any special consideration given to the extra cost that I know of.

Q. No special request made by the company that relates to that circumstance?

A. Correct.

Q. Do you know whether the company specifically made an adjustment to attribute that higher relative power cost to the company rather than to any other party?

A. I don't.

Q. So you're not sure of the regulatory treatment?

A. I'm not, no.

Q. But you are sure the company acknowledged human error in the situation?

A. Yes.

CHAIRMAN ELLENBECKER: Okay. Thank you.

Exhibit No. ___(RJF-14)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-14)

WYOMING PSE DOCKET NO. 20000-ER-02-184

EXCERPT OF TRANSCRIPT OF HEARING PROCEEDINGS

VOLUME VII

July 2, 2004

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF WYOMING

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING, CONSISTING OF A GENERAL RATE INCREASE OF APPROXIMATELY $30.7 MILLION PER YEAR, A THREE-YEAR RATE SURCHARGE FOR PREVIOUS POWER COSTS TO RECOVER $60.3 MILLION, AND AN ADDITIONAL THREE-YEAR RATE SURCHARGE TO RECOVER POWER COSTS OF $30.705 MILLION RELATED TO THE HUNTER NO. 1 GENERATING UNIT

Docket No.
20000-ER-02-184
(Record No. 7475)

TRANSCRIPT OF HEARING PROCEEDINGS
VOLUME VII
January 16, 2003

PURSUANT TO NOTICE duly given to all parties in interest, this matter came on for hearing on the 13th day of January, 2003, at the hour of 10:00 a.m., in the Hearing Room at 2515 Warren Avenue, Suite 300, Cheyenne, Wyoming, before the Public Service Commission, Chairman Steve Ellenbecker presiding, with Deputy Chairman Steve Furtney and Commissioner Kristin Lee also in attendance. Also present were Stephen G. Oxley, Secretary and Chief Counsel of the Commission, Christopher Petrie, Counsel of the Commission, and David Mosier, technical advisor of the Commission.

APPEARANCES

For the Applicant PacifiCorp:	MR. BRENT R. KUNZ Attorney at Law 2515 Warren Avenue, Suite 500 Cheyenne, Wyoming 82001
	MR. EDWARD HUNTER MS. KATHERINE A. McDOWELL MR. JENNIFER E. HORAN Attorneys at Law STOEL RIVES, LLP 900 S.W. Fifth Avenue, Suite 2600 Portland, Oregon 97204
	MR. JAMES M. VAN NOSTRAND MS. KENDALL J. FISHER Attorneys at Law STOEL RIVES, LLP 600 University Street, Suite 3600 Seattle, Washington 98101
For the Intervenor WIEC:	MR. ROBERT M. POMEROY, JR. MR. JAMES K. TARPEY MR. THOR NELSON Attorneys at Law HOLLAND & HART 8390 East Crescent Parkway Suite 400 Greenwood Village, Colorado 80111
For the City of Evanston and AARP:	MR. DALE W. COTTAM Attorney at Law HIRST & APPLEGATE 1720 Carey Avenue, Suite 200 Cheyenne, Wyoming 82001
For the Consumer Advocate Staff:	MR. DAVID J. LUCERO MR. DOUGLAS J. MOENCH MR. IVAN WILLIAMS Staff Attorneys Wyoming Public Service Commission 2515 Warren Avenue, Suite 300 Cheyenne, Wyoming 82002

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P R O C E E D I N G S

(Hearing proceedings reconvened
9:06 a.m., January 16, 2003.)

DEPUTY CHAIRMAN FURTNEY: Let's go on the record at this time. Mr. Hunter, do you have a procedural matter to bring up at this time?

MR. HUNTER: I do, Mr. Chairman. Mr. Williams, Bruce Williams, who is the company's witness on cost of debt and preferred stock, has no questions, has aroused no issues in this proceeding. We'd request that he be excused and at the appropriate time we offer and mark his testimony without him appearing at this proceeding.

DEPUTY CHAIRMAN FURTNEY: Do any of the parties have opposition to this matter?

MR. MOENCH: Consumer Staff has no opposition.

DEPUTY CHAIRMAN FURTNEY: Okay. We'll grant that request and we'll take that up as you bring it up, I guess.

MR. HUNTER: In fact, probably we'll put it on with Mr. Hadaway during that time we're talking about cost of capital.

DEPUTY CHAIRMAN FURTNEY: We'll take it up at that time.

for like the last 10 or 15 years whereby we include all outages in our base rate calculation with the one exception in this case, we didn't included the Hunter 1 outage because it's so far different than all the other outages we've experienced at the company in terms of timing, magnitude, extent of damage, things of that nature.

Q. All right. So just so we're clear, your current position, then, is not the position stated here in your direct that you should remove extraordinary outages. It's that you should include in your outage calculation even extraordinary outages except for Hunter; is that correct?

A. That's our updated position, yes.

Q. Okay. Thank you.

Now, in handling outages, has the company made any adjustments in its net power cost calculation to remove the costs for ratepayers of the Jim Bridger 4 outage in the year 2000?

A. We did not.

Q. And are you aware that's the outage that one of the company's witnesses earlier said was the company's fault in the testimony that we just had over the past few days?

A. Yeah. I believe Mr. Cunningham indicated that

that was something that was a result of company actions. And we still don't recommend that that type of outage should be removed from the company's calculation. As in any business, you know, accidents happen, errors happen and so forth, and so it appears to us that it's more of a normal occurrence.

If, in fact, the company had a history of an exorbitant number of human errors in relation to this, I would expect the Commission to take notice of that. However, given the fact that it's a relatively isolated incident and it happens at all utilities, I would think it's a cost that should be reasonably recovered.

Q. So the outage calculation includes outages whether it's the company's fault or not; is that right?

A. The outage calculation includes all outages except Hunter 1.

Q. Okay. Let me ask you to -- let's talk about a different topic that starts on page 21 of your direct testimony. Do you have that?

A. I do.

Q. I need to direct your attention, sir, to lines roughly 13 and 14. I need to ask you a couple of questions about PacifiCorp's proposal to share 20 percent of excess net power costs through, in your words, "May 2001, the expected end of the rate cap period." Do you

Exhibit No. ___(RJF-15)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-15)

OUTAGES DUE TO PACIFICORP ERRORS

July 2, 2004

EXHIBIT NO.__(RJF-15)
OUTAGES DUE TO PACIFICORP ERRORS

1994-1997			
NERC Code	**DESCRIPTION**	**HOURS**	**MWH**
9920	CONTRACTOR ERROR	1	n/a
9910	MAINTENANCE ERROR	45	n/a
9900	OPERATOR ERROR	66	n/a
9720	OTHER SAFETY PROBLE	0	n/a
	Total	112	
Oct. 1998-Sep. 2002			
9920	CONTRACTOR ERROR	59	27304
9910	MAINTENANCE ERROR	159	69917
9900	OPERATOR ERROR	112	51881
9720	OTHER SAFETY PROBLE	2	1281
	Total	333	150383
	% Increase	298%	
			Avg mW
	TY IMPACT - MWH	37596	4.29
	Average cost per mW		139914
	Adjustment		600475

Exhibit No. ___(RJF-16)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

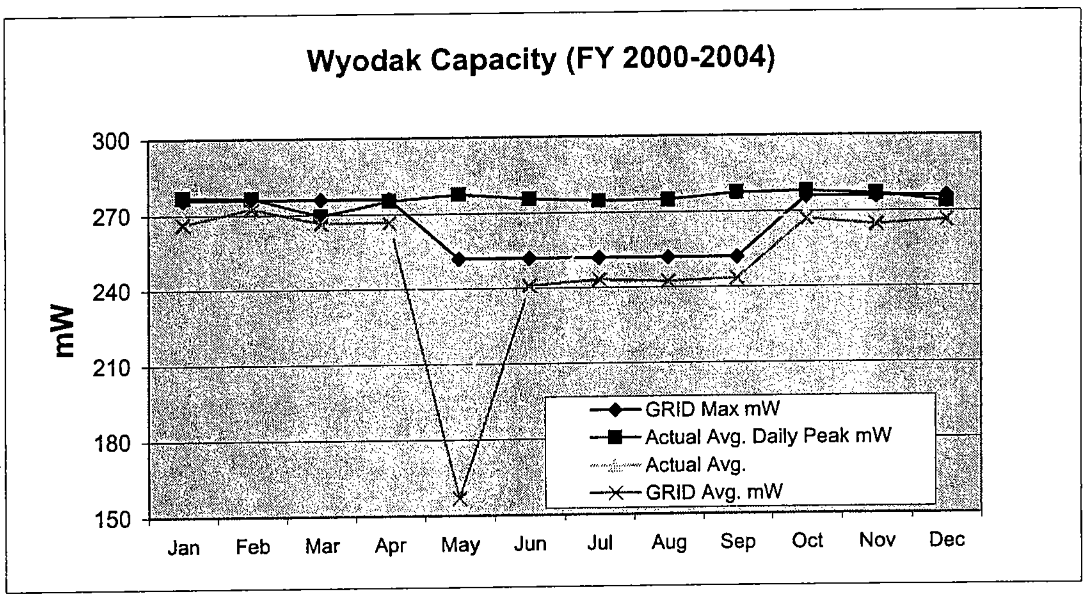
EXHIBIT NO.__(RJF-16)

COMPARISON OF ACTUAL AND GRID WYODAK

July 2, 2004

Exhibit No.__(RJF-16)
Comparison of Actual and GRID Wyodak
Generation and Capacity Data

	GRID Max MW	*Actual Avg. Daily Peak*	*Variance %*	GRID Avg. mW	*Actual Avg. mW*	*Variance %*
Jan	276	*277*	*0.4%*	266	*268*	*0.5%*
Feb	276	*277*	*0.2%*	272	*267*	*-2.2%*
Mar	276	*270*	*-2.4%*	267	*257*	*-3.8%*
Apr	276	*275*	*-0.3%*	267	*264*	*-1.1%*
May	252	*278*	*10.2%*	157	*202*	*29.1%*
Jun	252	*276*	*9.4%*	241	*239*	*-0.9%*
Jul	252	*275*	*9.0%*	243	*260*	*6.9%*
Aug	252	*275*	*9.1%*	242	*262*	*8.1%*
Sep	252	*278*	*10.1%*	244	*267*	*9.4%*
Oct	276	*278*	*0.7%*	267	*269*	*0.7%*
Nov	276	*277*	*0.4%*	265	*264*	*-0.4%*
Dec	276	*274*	*-0.8%*	266	*253*	*-5.1%*
Avg. May-Sep	252.0	*276.1*	*9.6%*	225.5	*246.1*	*9.1%*
Avg. Other Months	276.0	*275.3*	*-0.3%*	267.2	*262.8*	*-1.6%*
Avg. Jul-Sep.	252.0	*275.7*	*9.4%*	243.1	*262.9*	*8.1%*
Avg. Dec.- Feb.	276.0	*275.8*	*-0.1%*	268.4	*262.4*	*-2.3%*
All Months	266.0	*275.6*	*3.6%*	249.8	*255.8*	*2.4%*



Notes: Daily Peak Data Based on April 1999 to March 2004 Data
Average Hourly mW Based on January 1998 to October 2003
GRID Results based on April 2003 to March 2004 Pro-Forma Period

Exhibit No. ___(RJF-17)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-17)

UTAH PSC DOCKET NO. 01-035-37

EXHIBIT UP&L ___.6 (JM-6)

REDACTED

July 2, 2004

Redacted
Exhibit No.__(RJF-17)
Pages 1 to 14 of 14

Exhibit No. ___(RJF-18)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-18)

EXCERPT OF DEPOSITION OF ANDREA KELLY

July 2, 2004

BEFORE THE WASHINGTON UTILITIES
AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY Respondent.	Docket No. UE-032065

DEPOSITION OF ANDREA L. KELLY

BE IT REMEMBERED, that the deposition of ANDREA L. KELLY was taken in the above-referenced cause, at the offices of Davison Van Cleve, 1000 Southwest Broadway, Portland, Oregon, on June 22, 2004, at 9:00 a.m., and was reported in stenotype by Kelly Lee Polvi, Court Reporter and Oregon Notary Public.

PERSONAL APPEARANCES:

Melinda J. Davison, Irion Sanger, Davison Van Cleve.

George M. Galloway, James Van Nostrand, Stoel Rives, LLP;

Robert W. Cromwell, Jr., Washington State Assistant Attorney General.

TELEPHONIC APPEARANCES:

Shannon Smith, Washington State Assistant Attorney General, and Roger Braden.

STATE OF OREGON)
) ss.
COUNTY OF POLK)

I, Kelly Lee Polvi, hereby certify that I am a former Official Reporter for the Third and Twelfth Judicial Districts of Oregon, formerly certified in the states of Oregon, California, and Texas; I am an Oregon Notary Public and Official Court Transcriber; that I reported in machine shorthand the foregoing proceedings and then transcribed my shorthand notes into the typewritten transcript, consisting of 6 pages, and that the said transcript constitutes a full, true and accurate record of the proceedings, as requested, to the best of my knowledge, ability and belief.

Dated this 23rd day of June, 2004, at Salem, Oregon.

KELLY LEE POLVI
Court Reporter and Transcriber
Oregon Notary Public

JUNE 22, 2004, PORTLAND, OREGON

ANDREA L. KELLY,

the witness, called by the Intervener, ICNU, having been first duly sworn, was examined and testified as follows:

EXAMINATION

BY MS. DAVISON:

Q Could you please state your full name?

A Andrea L. Kelly.

Q Could you please provide your business address.

A 825 Northeast Multnomah, Suite 300, Portland, Oregon, 97232.

Q I'm going to hand you a copy of your Direct Testimony and this was filed before the Washington Utilities and Transportation Commission in docket number UE-032065. And I'm just going to refer to this as "the Washington rate case" throughout the deposition.

Are you the same Andrea Kelly that submitted testimony in the Washington rate case?

A Yes.

Q The testimony that I've handed to you, is that true and correct today?

A I believe so.

Q There is nothing that you would change today about your testimony?

A Not that I can think of.

Q If you turn to page two of your testimony, lines 21 through 22, is PacifiCorp advocating an MSP solution that contains elements of Dynamic and Hybrid Proposals?
A Yes, as well as some new concepts.
Q And what are those new concepts?
MR. GALLOWAY: Is your question is it advocating in this case or broadly?
MS. DAVISON: My question is this case.
MR. GALLOWAY: Okay, that's a useful clarification.
Do you understand the question?
THE WITNESS: Yes.
MR. GALLOWAY: Okay.
THE WITNESS: Well, I think if you turn to page five and six of my testimony, it describes some of the ways that the MSP solution allows individual states to pursue policy initiatives as part of that. Permitting states to adopt Direct Access Programs, Demand-Side Management Programs, Portfolio Standards, special contracts, each of those elements can be in either a Dynamic or a Hybrid solution.
Q (BY MS. DAVISON.) If you turn to page 11 of your Direct Testimony, lines four and five refer to a coal endowment. Is PacifiCorp still advocating a coal endowment in this case?
A Yes, for purposes of this case we are.
Q If you turn to page 13 of your Direct Testimony,

lines three and four, is Oregon afforded a one-time irrevocable option to participate in the coal endowment?
A Yes, under this Proposal.
Q On page 15 of your Direct Testimony, is PacifiCorp advocating the Portfolio Standards that are set forth on page 15?
A Excuse me, could you rephrase the question?
Q Sure. Is PacifiCorp still advocating the Portfolio Standards that are set forth on page 15 of your Direct Testimony?
A We are not advocating Portfolio Standards in my testimony, we are advocating a treatment of the Portfolio Standards for allocation purposes.
Q Are you still advocating the same treatment of Portfolio Standards?
A Yes, we are.
Q Is the Company -- and I refer to PacifiCorp and the Company interchangeably -- is the Company still requesting that the WUTC adopt the Protocol that's set forth in ALK-2?
A Yes, the Company, for purposes of this Washington rate case, is proposing this Protocol.
Q Has PacifiCorp revised the Protocol since your December 2003 filing in Washington?
A Yes, there have been revisions to the Protocol.
Q And with these revisions to the Protocol did

A At some point we do plan to file a Revised Protocol in Wyoming.

Q Have you had any conversations with the Wyoming Staff indicating that you will file a Revised Protocol?

A I have not had any conversations since the meeting in Boise in respect to filing of revisions.

Q Ms. Kelly, I'm going to hand you a letter dated May 26th, 2004. If you could look that over and let me know if you have seen this letter previously.

A Yes, I have.

Q And isn't it correct that this is a letter to Stephen Oxley at the Wyoming PSC from Paul Hickey indicating that PacifiCorp intends to file a Revised Protocol on June 22nd?

A Yes.

MS. DAVISON: I'd like to have this marked as Exhibit One.

THE WITNESS: It's mentioned in the note that Steve is not part of the Commission Staff, as your prior question asked if I had spoken --

MR. GALLOWAY: That's all right.

(Whereupon Deposition Exhibit Number One was marked for identification.)

Q (BY MS. DAVISON.) The current version of the Revised Protocol that you are working with in Utah, is it fair to say that you've had ongoing meetings, conversations, with the Utah parties in accepting revisions to that Protocol?

A I think it's fair to say we've had settlement negotiations around it.

Q And have those settlement negotiations resulted in revisions to the Protocol?

A Yes.

Q And is that a fair characterization of the Oregon process as well?

A I think so.

Q Has PacifiCorp filed any revisions to the Protocol before the Washington Commission?

A No.

Q And why not?

A On the advice of legal counsel.

Q Is the Protocol that is attached to your Direct Testimony as ALK-2 the version of the Protocol that you are advocating for adoption in Utah and Oregon?

MR. GALLOWAY: Objection. I'm sorry, I don't -- your question was different than I thought. I withdraw the objection.

THE WITNESS: Could you repeat the question?

MS. DAVISON: Could you read it back?

(Record read by reporter.)

THE WITNESS: No, it's not.

Q (BY MS. DAVISON.) And why are you advocating different versions of the Protocol or a different version of the Protocol in Washington than you are in Oregon and Utah?
A Due to different procedural requirements.
Q What is the Company's objective with regard to Protocol?
A I don't understand the question.
Q What is PacifiCorp seeking to accomplish through this multi-state process?
A Our goal has been to have a common allocation methodology among our states.
Q Is your goal achieved by having different versions of the Protocol adopted by different states?
A Not completely, but it is unfortunately where we are at this point.
Q Is it possible for you to supplement your testimony when you reach agreement on a Second Revised Protocol in Washington?
MR. GALLOWAY: Objection, calls for a legal conclusion.
MS. DAVISON: If you could answer the question in terms of your knowledge and understanding of the operation of the Washington Commission.
THE WITNESS: I don't know.
Q (BY MS. DAVISON.) You don't know if it's possible

Q (BY MS. DAVISON.) Do you intend to update your testimony with regard to the current version of the Protocol on rebuttal?

MR. GALLOWAY: Are you referring to the Washington case?

MS. DAVISON: Yes.

THE WITNESS: We don't have any current strategy around what we're going to do on rebuttal.

Q (BY MS. DAVISON.) Have you had any conversations outside the presence of counsel about what you intend to do in Washington with regard to updating the Protocol?

A Not that I recall.

Q Have you had any conversations outside the presence of counsel discussing the possibility of filing a separate MSP case in Washington that seeks the adoption of a Second Revised Protocol?

A I don't believe so.

Q Do you consider the changes from the original Protocol to the First Revised Protocol to be substantive?

A I think the changes are material but I don't believe they are substantive from a revenue-requirement standpoint.

Q Can you explain that answer further?

A I am aware, but I'm not the witness and I'm not familiar with a data request that was provided to Staff and ICNU that restated the test period revenue requirement under

Exhibit No. ___(RJF-19)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
vs.	)	**Docket No. UE-032065**
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-19)

VALUE OF HYDRO

July 2, 2004

Exhibit No.__(RJF-19)
Value of Hydro and Not Captured in Protocol

Pacific Hydro Credit	West Hydro
Hydro Cost Fuel Cost $/mWh	$0.00
Huntington Fuel Cost	$8.38
System Average Thermal Fuel Cost	$10.78
Understated Fuel Credit	$2.40
mWh	4,128,973
Fuel Credit	$9,927,034
Net Fuel Credit	$9,927,034
Load Shaping Value - $/mWh	$2.29
Load Shaping Value - $	$9,455,348
Dynamic Overlay Value	$12,822,425
Total System Value	$32,204,807
Total Value Ignored - $	$32,204,807
Washington Allocation - DEP	17.3%
Washington Allocation - SE	8.6%
Additional Allocation	8.6%
Value Understatement	$2,784,583
Net Adjustment	$2,784,583

Exhibit No. ___(RJF-20)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	
	)	**Docket No. UE-032065**
vs.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-20)

REVISED PROTOCOL ASSUMPTIONS COMPARISON

REDACTED

July 2, 2004

Redacted
Exhibit No.__(RJF-20)
Pages 1 to 2 of 2

Exhibit No. ___(RJF-21)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	**Docket No. UE-032065**
vs.	)	
PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY	)	
Respondent.	)	

EXHIBIT NO.__(RJF-21)

GADSBY AND WEST VALLEY ADJUSTMENTS

July 2, 2004

Exhibit No.__(RJF-21)
Gadsby and West Valley Adjustments

	Gadsby	West Valley
TY Revenue Requirement:	10,253,157	15,137,463
Fuel Expense	15,046,730	26,974,371
Thermal Revenue	20,731,371	33,352,608
Net TY Cost	-4,568,516	-8,759,226
Washington Allocation	8.96%	8.96%
TY Impact	-$409,353	-$784,854
Reverse Adj. 4, 19	$58,755	$279,203
Total Net Adjustment	-$350,598	-$505,651
	Combined	-$856,249

Exhibit No. ___(RJF-22)
Docket No. UE-032065
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY Respondent.	**Docket No. UE-032065**

EXHIBIT NO.__(RJF-22)

LETTERS REGARDING WEST VALLEY LEASE

July 2, 2004

Don Furman
Senior Vice President
Regulation & External Affairs
Direct (503)813-5525
Fax (503)813-7277

825 N.E. Multnomah, Suite 2000
Portland, Oregon 97232
(503) 813-5000

PACIFICORP
PACIFIC POWER UTAH POWER

May 28. 2004

Ken Canon, Executive Director
Industrial Customers of Northwest Utilities
825 NE Multnomah, Suite 180
Portland, OR 97232

Re: PacifiCorp West Valley Generation Facilities

Dear Ken:

I appreciate the opportunity to respond to your letter to Judi Johansen of May 12 regarding PacifiCorp's West Valley Project. I received a similar letter from Lee Sparling on May 24. I have enclosed my response to him, which addresses the issues raised in your letter. In summary, PacifiCorp believes that the West Valley lease is an important and cost-effective resource in reliably meeting our load service obligation. One of the additional attractive qualities of the lease is the degree of flexibility it provides PacifiCorp. In this instance, PacifiCorp intends to take advantage of that flexibility by providing written notice of termination prior to June 1, 2004. This step will provide the Company a four-month window to evaluate whether to terminate the lease as of May 31, 2005 or rescind the termination and permit the lease to continue.

As I indicated in my letter to Mr. Sparling, we propose to provide informal updates or briefings to Staff throughout the summer along the Company's path to a decision. We are pleased to include ICNU in these briefings as well.

Please contact Christy Omohundro or me if you have further questions or comments.

Sincerely,

Don Furman
Senior Vice-President

cc: Chairman Lee Beyer
Commissioner Ray Baum
Commissioner John Savage
Lee Sparling
Marc Hellman
Judi Johansen
Christy Omohundro

Don Furman
Senior Vice President
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PACIFICORP
PACIFIC POWER UTAH POWER

May 28, 2004

Lee Sparling
Director, Utility Program
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: PacifiCorp West Valley Generation Facilities

Dear Lee:

This responds to your letter of May 24, 2004 regarding the West Valley lease.

Background

The Staff investigated the West Valley lease in UI 196. In the Staff Report, adopted by the Commission in Order 02-361, Staff recommended approval of the Company's request to enter into the West Valley lease with West Valley Leasing Company (a subsidiary of PPM) based upon its conclusions that the lease met the Commission's "lower of cost or market" transfer policy and that PacifiCorp was "paying a fair and reasonable price under the Lease." UI 196, Staff Report at 8 (May 22, 2002).

Consistent with the Staff's findings, the West Valley lease has proven to be an important and economic resource for the Company, providing benefits to the overall system in the form of lower net power costs and increased reliability. In the Stipulations approved by the Commission in Dockets UE 134 and UE 147, the lease was included in PacifiCorp's net power costs (in the latter case, the parties did agree to adjust Oregon allocation factors to address certain Utah-based resources, including the West Valley lease).

PacifiCorp has acquired and planned other resource additions since the Oregon Commission approved the West Valley lease, including a contract with Deseret Generation & Transmission Cooperative and its Currant Creek plant (which will come on line in two phases - 2005 and 2006). Notwithstanding these additions, the Company is facing a system short position, as shown in the most recent IRP Update. Thus, the need for the West Valley lease appears to have increased, rather than decreased, since the Commission originally approved the lease.

Termination Option

The provisions of the West Valley lease allow the Company to terminate the lease in year three or in year six. The Company's first option to terminate the lease is prior to June 1, 2004. Under the lease, the Company may rescind the termination prior to September 30, 2004. If the Company does not rescind such a termination notice then the lease would terminate May 31, 2005, and the Company would forego the 200 MW West Valley resource thereafter (unless the Company exercises its parallel purchase option).

In reviewing the West Valley lease, Staff commented that "these options provide PP&L with a hedge against changes in market prices and loads in the future and to ultimately decide which is the best economic choice (continue leasing, terminate leasing, or purchase the project.)" UI 196, Staff Report at 5 (May 22, 2002). PacifiCorp agrees that the flexibility of the West Valley lease is one of its attractive features.

PacifiCorp's Position on Termination

PacifiCorp has decided to take advantage of the flexibility of the West Valley lease by providing PPM Energy written notice of its termination prior to June 1, 2004. This step will provide the Company a four-month window to evaluate whether to terminate the lease as of May 31, 2005, or rescind the termination and permit the lease to continue. While PacifiCorp believes that the West Valley lease may very well remain its best option for reliably meeting a portion of its resource needs, PacifiCorp intends to conduct a robust review of this issue over the summer, including an evaluation of short-term market opportunities.

PacifiCorp's Position on a Proposed Staff Investigation

It is not clear whether your letter suggested a Staff investigation out of concerns that PacifiCorp would not trigger the termination option by June 1, concerns that PacifiCorp would not evaluate the West Valley lease against other market alternatives, or both. We think that the fact that PacifiCorp is planning to take both of these steps should obviate the need for any kind of formal Staff investigation. This is especially true given the fact that Staff and other parties will have an opportunity to scrutinize whatever decision PacifiCorp makes on the West Valley lease in a subsequent prudency review over the lease expense or the replacement resource expense.

Now that we understand that Staff has an interest in this issue, we are pleased to provide informal updates or briefings throughout the summer along the Company's path to a decision. This kind of informal approach is consistent with past practices in Oregon on resource decisions of this sort. In contrast, a formal investigation on whether a utility should make a certain resource decision is highly unusual in a State that has generally eschewed resource pre-approval.

We hope that PacifiCorp's approach to the West Valley lease termination, along with the Company's willingness to provide informal updates or briefings to Staff during the four-month review window, satisfies the concerns that precipitated your letter. Please contact Christy Omohundro or me if it does not or if we can provide more information.

Sincerely,

Don Furman
Senior Vice-President

cc: Marc Hellman
Ed Busch
Ken Canon, ICNU
Bob Jenks, CUB
Judi Johansen
Christy Omohundro
Paul Wrigley