Exhibit No. ____ (APB-1T)
Docket No. UE-032065
Witness: Alan P. Buckley

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP, d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET NO. UE-032065

TESTIMONY OF

ALAN P. BUCKLEY

STAFF OF THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

July 2, 2004

I. INTRODUCTION

Q. Please state your name and business address.

A. Alan P. Buckley, 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington 98504. My e-mail address is abuckley@wutc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission as a Senior Policy Strategist. Among other duties, I am responsible for analyzing rate and power supply issues as they pertain to the investor-owned utilities under the jurisdiction of this Commission.

Q. What are your education and experience qualifications?

A. I received a B.S. degree in Petroleum Engineering with Honors from the University of Texas at Austin in 1981. In 1987, I received a Masters of Business Administration degree in Finance from the University of California at Berkeley. From 1981 through 1986, I was employed by Standard Oil of Ohio (now British Petroleum-America) in San Francisco as a Petroleum Engineer working on Alaskan North Slope exploration drilling and development projects. From 1987 to 1988, I was employed as a Rates Analyst at Pacific Gas and Electric Company in San Francisco. Beginning in late 1988 until late 1992, I was employed by R.W. Beck and Associates, an engineering and consulting firm in Seattle Washington, conducting cost-of-service and other rate studies, carrying out power supply studies, analyzing mergers, and analyzing the rates of Bonneville Power Administration and the Western Area Power Administration. I came to the Commission in December of 1993, where I have held a number of positions including Utility Analyst, Electric Program Manager, and the position that I presently hold. I have been a witness in numerous proceedings before the Commission. I have been a witness in proceedings at the Bonneville Power Administration and at the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

1) Evaluate PacifiCorp's proposed Multi-State Process solution or "Protocol;"

2) Present Staff's inter-jurisdictional cost allocation proposal as a transitional approach for this case only;

3) Evaluate the Company's normalized test year net power cost study in the context of Staff's inter-jurisdictional cost allocation proposal, and address

the Company's acquisition of generating resources addressed in the Joint Report that was filed in compliance with the Commission's final order in Docket No. UE-991832;

4) Present Staff's proposed Washington allocated Net Power Cost consistent with the recommended inter-jurisdictional cost allocation methodology; and

5) Address other power supply and transmission cost issues.

Q. How is your testimony organized?

A. I have organized my testimony into the following sections:

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. ___ (ABT-2) through Exhibit No. ___ (ABT-7).

II. SUMMARY OF TESTIMONY AND STAFF RECOMMENDATIONS

Q. Before summarizing your testimony, please describe recent events in the Company's other jurisdictions regarding inter-jurisdictional cost allocation.

A. In mid-June of 2004, Staff obtained a copy of a "final draft" Multi-State Process (MSP) Utah Stipulation, in which the Company and parties to the Utah MSP proceeding appeared to agreed on an interstate allocation methodology for purposes of setting rates in Utah (draft Utah Revised Protocol). Under that agreement, the Company's revenue requirements for any general rate case initiated in Utah prior to July 1, 2008 will be capped, irrespective of costs. The cap is one of two outcomes, whichever produces the least impact on rates: 1) the Company's Utah revenue requirement resulting from the Utah Revised Protocol (discussed later in my testimony) or 2) a 1.25 percent increase until mid-June 2006, and a 1.5 percent increase after June 2006. All fixed and variable production and transmission costs will be based on the Rolled-in Allocation Method. The use of that particular allocation method, which no other state commission has accepted, allocates the lower cost power supply costs of the pre-merger Pacific Power & Light Company to the Utah jurisdiction.

The Company has not informed Staff or the Commission whether it has filed the draft Utah Revised Protocol. However the apparent finality of this draft leads Staff to believe that PacifiCorp has agreed to its provisions. Surprisingly, the agreed cap would be implemented subsequent to PacifiCorp's recent acquisition or proposed acquisition of several large generating facilities to serve the Company's increasing load requirements in Utah. Those facilities are principally located in the Wasatch Front, and they represent 1,379 Mega-Watts of capacity with a total installed cost of well over $750,000,000. Staff recently was notified that ~~this~~ the West Valley Project lease was terminated and the power will be replaced through a future RFP process.

The recent events in Utah, coupled with the fact that PacifiCorp filed a Revised Protocol and supporting testimony in Oregon, significantly undermine the credibility of the Washington Protocol at issue in this docket.

Q. How have these recent developments impacted your analysis of inter-jurisdictional cost allocation and power supply costs in this proceeding?

A. Because the Company has not filed a revised protocol in Washington that reflects the revised versions from Oregon or Utah, I have analyzed the original Protocol filed with the Company's direct case. However, PacifiCorp's decision to advocate for the original Protocol even though it has submitted a revised inter-jurisdictional cost allocation proposal in Oregon and likely will file a different proposal in Utah (that includes a stipulation for a rate cap that effectively limits rate increases in Utah where the Company is incurring significant costs to serve growing load), is untenable. Furthermore, the Company's proposal to allocate portions of these costs to Washington, through its proposed 13 percent rate increase, is unconscionable in light of the Utah Stipulation. PacifiCorp appears to be doing little if anything to properly allocate costs in its largest jurisdictions, except to further perpetuate the so-called "regulatory black hole." Staff recommends that this Commission deny the Company's proposal to recover these costs in Washington.

Q. Can you briefly summarize your testimony?

A. The Company's revenue requirement for Washington operations is based on its proposed MSP solution or "Protocol." This includes the inter-jurisdictional allocation of power supply and transmission related expenses and fixed costs. The Company has prepared a normalized test year power cost study, and then derived a Net Power Cost for Washington operations based on the allocations proposed in the Protocol.

I begin with a review of recent Commission orders addressing power supply issues. I then review the Protocol, including the Company's analyses supporting its use. This review is followed by an evaluation of the Protocol from a general policy and principle viewpoint, as well as from a more detailed resource perspective. I then address recent actions by the Company and other parties concerning revised Protocol filings in both Oregon and Utah. By filing revised versions of the Protocol in its largest jurisdictions, the Company flatly discredits many of the features contained in the Washington Protocol that it filed in this docket. This testimony is followed by Staff's recommendation regarding the Protocol and the inter-jurisdictional allocation methodology Staff proposes for use in this proceeding only. I then present Staff's recommendations for a future process to develop an appropriate method of determining the Company's costs of serving Washington's operations.

In the next section of my testimony, I address Staff's determination of Washington allocated power supply and transmission expenses in the context of the recommended transitional inter-jurisdictional costs allocation methodology. I also present Staff's recommended adjustments related to fixed costs of power supply and transmission resources, again in the context of the proposed inter-jurisdictional cost allocation methodology. Finally, I address a proposed adjustment related to RTO expenses.

Q. Please summarize Staff's recommendations in this proceeding.

A. The Staff recommends that the Commission take the following actions:

1. Reject the Company's filed "Protocol;"

2. Adopt the transitional inter-jurisdictional cost allocation methodology proposed by Staff for purposes of this proceeding only;

3. Reject the Company's proposed Washington allocated Net Power Supply Cost based on the Protocol and "rolled-in" resource allocations;

4. Adopt Staff's Washington allocated Net Power Cost based on the use of the Staff's transitional inter-jurisdictional allocation methodology with recommended adjustments;

5. Adopt Staff's Washington allocated power supply and transmission plant balances based on Staff's transitional inter-jurisdictional allocation methodology with recommended adjustments;

6. Accept the Company's acquisition of James River and Hermiston generating resources as being prudently acquired for purposes of determining the cost to serve Washington's operations;

7. Take no action regarding the remaining generating resources contained in the Joint Report, as well as the Gadsby and West Valley Projects;.

8. Accept Staff's adjustment to Company and outside service expenses related to RTO development;

9. Order the Company to work with Staff and other interested parties to develop a Washington stand-alone approach for determining just and

reasonable costs for its Washington operations, prior to filing its next general rate case or other filings requesting recovery of additional costs;

10. Prohibit the Company from filing any of the revised Protocol versions in its rebuttal case, because allowing the Company to do so at that late date would preclude other parties from undertaking any meaningful analysis. Such a rebuttal filing would be particularly unwarranted because the Company filed a revised Protocol in Oregon and likely will file a revised Protocol in Utah, and there is no reason why it could not have filed a revised Protocol in this docket.

III. REVIEW OF RECENT PACIFICORP POWER SUPPLY ISSUES

Q. Why do you believe a review of recent power supply issues is important in this proceeding?

A. This is a complicated case. As the Commission noted in its Sixth Supplemental Order in Docket No. UE-020417, the Commission has not closely scrutinized PacifiCorp's operations in a general rate case for many years. Since the Company's last general rate case, it has merged with Utah Power & Light Company, acquired numerous power supply resources, been acquired by Scottish Power, operated under a transition plan, considered corporate restructuring, experienced a power crisis, and now the Company has filed either general rate cases and/or inter-jurisdictional cost allocation proceedings before the various state commissions. Considering these events, I believe it is appropriate to briefly review the most relevant power supply issues.

Q. Please identify the most recent power supply issues impacting Washington ratepayers.

A. Beginning with the 1988 merger of Pacific Power & Light Company and Utah Power & Light Company, the power supply issues most relevant to Washington ratepayers include:

- the merger of a higher cost system (Utah Power) into a lower cost system (Pacific Power);
- the treatment of power supply expenses in the Company's corporate restructuring proposal;
- the effect on power supply expenses from the sale of the Company's interest in the Centralia Generating Plant;
- the effect of the acquisition of additional resources by the Company to meet load requirements or other strategic goals;
- the Company's 2002 request to defer excess power costs; and

- the Company's recent MSP to develop an inter-jurisdictional cost allocation methodology.

Reviewing these issues will help frame the issues in this docket.

Q. Why is inter-jurisdictional cost allocation a vital issue in determining the appropriate power supply and transmission related costs for Washington operations?

A. Inter-jurisdictional cost allocations are the foundation for determining the power supply and transmission-related costs necessary to serve Washington customers. In this proceeding, Staff based its determination of Washington-allocated Net Power Cost on the extent that the Company's costs are assigned and allocated in a multi-state jurisdictional environment. Inter-jurisdictional cost allocations have been a major issue before this Commission since the Pacific Power and Utah Power merger in Cause U-87-1338-AT.

Q. What power supply issues arose during the Pacific Power and Utah Power merger?

A. In that proceeding, the Commission addressed several significant power supply issues, including: 1) the integration of Pacific Power's low cost resource system, which included significant hydro-based generation, and Utah's higher cost, predominantly thermal system; 2) inter-jurisdictional cost allocations for a utility with two operating divisions and with different cost structures; and 3) the acquisition of new resources for the combined utility.

Q. During that merger docket, did the Company agree to resolve concerns related to these power supply issues?

Yes. The Company committed to reconvene the jurisdictional allocation committee to resolve the power supply costs and benefits allocation issues.[1] The Company also testified that, "[t]he merger will not significantly increase the regulatory burden of the state and federal regulatory commissions."[2] The Company further assured this Commission that Washington ratepayers would not have to subsidize the immediate rate reduction promised to Utah Power customers:

> [T]hrough the allocation process, we [PacifiCorp] will insure and I'm sure you [the Commission] will insure that there is no cross subsidization whereby a Washington customer or any Pacific Power & Light customer is helping to subsidize that price reduction. If there is a subsidy required, it's going to be a subsidy by the shareholder. (*Cause U-87-1388-AT, Tr. 733*)

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[1] Rebuttal Testimony of Fredrick Reed, Cause U 87-1338-AT, Exhibit T-43, at 1, lines 16-20.

[2] *Id.* at 1, l. 29 through 2, l.1

Finally, in its order approving the merger, this Commission stated that:

> The Commission continues to be concerned about the effects on Pacific's ratepayers of merging with a higher cost system, and believes the integration of the power supply function for the two companies should be done in a manner consistent with Pacific's least-cost planning process, now getting underway. In the meantime, the Commission views Pacific's current average system costs as the appropriate basis for rates. (*Order in Docket No. U-87-1338-AT, at 14*)

The Commission also accepted the Company's agreement to reconvene the jurisdictional allocation committee with all involved states within six weeks of final approval of the merger.[3]

Q. Did the jurisdictional allocation committee meetings resume upon final approval of the merger?

A. Yes. The PacifiCorp Inter-jurisdictional Taskforce on Allocations ("PITA") meetings resumed. I believe it is safe to say that the meetings were not entirely successful from Washington's point of view and I suspect this is true from the Company's perspective as well.

Q. Why do you believe that the PITA meetings were not successful from PacifiCorp's perspective?

[3] Order in Docket No. U-87-1338-AT, at 15.

A. The Company cited the breakdown of the inter-jurisdictional cost allocation process as one of the reasons behind its earlier corporate restructuring proposal ("Restructuring Proposal"), in which the Company acknowledged that the existing system for inter-jurisdictional cost allocation was broken. The Company specifically mentions the role the inter-jurisdictional cost allocations played in the ultimate loss it sustained in selling its interest in the Centralia Generating Plant and Mine, in spite of a sales price well above book value. (Docket No. UE-001878, Restructuring Proposal, at 21.)

Q. What other issues did the Company cite as support for the Restructuring Proposal?

A. The Company recognized the diverse views of its regulators. Some of the views specifically included: the appropriate nature and timing of direct access; the desirability of load growth and how any growth should be met; enthusiasm about renewables and demand side management, and how to pay for them; the preference of one type of generating resource over another (some states favor new coal plants); the treatment of special contracts that further local economic development; and the ultimate fate of the least-cost planning process under certain legislation. These continue to be open issues in PacifiCorp's service territory, and are issues in this docket.

Q. Please describe the basic features of the Company's Restructuring Proposal.

A. In general, the proposal would have split the Company into seven separate entities. PacifiCorp would have retained ownership and control of generating and transmission assets, however, the control and operation of transmission assets would have been assigned to a regional transmission organization. The remaining non-transmission utility assets would have been allocated among six new state electric companies. The most intriguing aspect of the proposal for purposes of this proceeding was the proposal for each state to acquire the necessary power supply to serve its utility customers pursuant to a power sales contract. The contract would have provided for PacifiCorp's current Washington requirements, with future requirements being met through additional agreements with the Generation Company or third-party suppliers.

Q. What was the outcome of the Company's Restructuring Proposal?

A. The Company filed a motion to dismiss the application, without prejudice, in order to facilitate the participation of Washington in the MSP. The Commission granted the motion in its Order of Dismissal in Docket No. UE-001878, issued on April 8, 2002.

Q. Why is the sale of the Company's interest in the Centralia Generating Plant and Mine an issue in this proceeding?

A. It is an issue for two reasons. First, in this proceeding we are addressing the costs of replacement power for a significant resource hole that was created when the Centralia Generating Plant was sold. Second, it appears, based on the Company's Joint Application, that the ultimate "loss" sustained as a result of the sale due to differing jurisdictional treatments was the "straw-that-broke-the-camel's-back" as far as inter-jurisdictional allocations were concerned.

Q. Can you elaborate on the Centralia replacement cost issue?

A. Yes. The Company has a purchase agreement for 400 MW of power through June 30, 2007 from Transalta, the new owner of Centralia. The amounts related to this purchase are included in the calculation of test year normalized net power costs in this proceeding.

Q. The Company contends that it suffered a loss from the sale of Centralia. How did this claimed "loss" occur?

A. In the asset sale proceedings before this Commission, the Company used an allocation principle where the pre-merger and post-merger assignment of resources to the old Pacific and Utah divisions were recognized. Although there have been some post-merger additions to the Centralia facility, there was a much higher percentage of pre-merger plant. Under the Company's allocation principle, most of the gain from the sale was allocated to the Pacific division jurisdictions. However, it is Staff's understanding that the Utah Commission adopted a rolled-in allocation methodology that allocated the gain on a system-wide basis, which resulted in more than 100 percent of the gain being allocated to ratepayers. Therefore, it appears that the Utah Commission's adoption of a rolled-in allocation methodology in general rate case proceedings and subsequently in its Centralia sale order led to the "loss," and the acknowledgement that the inter-jurisdictional allocation process was broken.

Q. How do the issues surrounding the Centralia sale affect your analysis in this proceeding?

A. In approving the sale,[4] this Commission made plain its view that PacifiCorp was required to prudently manage its resources, even if multiple ownership of resources presented difficulties. Staff believes the Commission should carry this principle forward in reviewing PacifiCorp's proposed inter-jurisdictional cost allocation methodology. In other words, PacifiCorp—not ratepayers—bears the

[4] Second Supplemental Order, Docket Nos. UE-991255 *et al.*,¶ 84.

burden of the regulatory risks associated with operating in a multi-jurisdictional environment.

Q. What is the significance in this proceeding of the acquisition of generating resources since 1986?

A. As discussed by PacifiCorp witness Mr. Widmer, the Stipulation approved by Commission Order in Docket No. UE-991832 required the Company to specifically demonstrate the prudence of resources acquired since 1986 in its next general rate case. As explained by Mr. Widmer, the acquisition of the Craig, Hayden, Cholla Unit 4, James River Cogeneration, Hermiston Cogeneration, and Foote Creek Wind resources were addressed in a Joint Report, which has been included as Exhibit No. ___ (MTW-4). It is clear from the Joint Report, and from the testimony of Mr. Widmer, that neither Staff, nor other interested parties, made any determination that the resources were acquired specifically to satisfy Washington load requirements. The Joint Report only concluded that those resources were acquired prudently on a system-wide basis. The Joint Report states:

> These resources could be subjected to investigations in future rate case proceedings that will determine whether these resources were acquired prudently to satisfy increased load growth or demand in Washington State, including consideration of the Company's commitments under merger agreements and orders, the impact of

> the 'inter-jurisdictional' allocation used by the Company, and particular load-growth characteristics of the Company's Washington service territory. *(Joint Report, Exhibit No.___ (MTW-4), at 62).*

Q. How could a resource that has been prudently acquired on a system-basis not be considered for purposes of determining the costs of Washington operations?

A. Several such scenarios come to mind. One possibility is the difference in load growth or load characteristics (such as load shape) between jurisdictions. It may be perfectly prudent to acquire a summer peaking resource for incremental summer peaking growth in one specific jurisdiction or control area. This does not mean that it is then appropriate to allocate the costs related to that resource to a jurisdiction that did not have incremental summer peaking needs. I discuss the load characteristics of the various jurisdictions later in this testimony. Another possible scenario is the effect on total costs from specific economic development goals of one state. One state may favor one generation type over another to meet load growth. From a pure system perspective, recognizing the legitimacy of a particular states goals, the acquisition of that resource may be prudent. However, it may be questionable whether that acquisition would meet the prudence standards of another jurisdiction, raising questions about the actual level of resource costs that should be borne by other jurisdictions, even if the energy was needed. Finally, a scenario could occur in which a resource is acquired by the Company for purposes of expanding wholesale market transactions. The acquisition alone does not make it necessarily prudent for an individual jurisdiction to bear the costs associated with that resource if a commission does not desire that exposure for its retail customers (of course it should not gain the benefits of that resource either).

Q. How can system versus jurisdictional prudence issues be reconciled?

A. The appropriate method to determine the prudence of resource additions for ratemaking purposes is to evaluate them in the context of State specific requirements. This is really the only way to truly protect retail customer when a utility crosses several jurisdictions with different load and regulatory characteristics. This requirement should also form the context in which inter-jurisdictional cost allocation methodologies are developed. I disagree with the Company's representation that operating and planning from the perspective of one state would necessarily result in sub-optimal financial results and that all customers would pay higher costs. (Exhibit No. __ (GND-1T), at 20, lines 15-17). I also disagree with the conclusion of the Company that the finding of prudence from a system basis forms a "sound basis" for concluding that acquisitions are prudent and, therefore, eligible for inclusion in Washington rates. (Exhibit No. ___ (MTW-1T), at 20, lines 19-22).

Q. Why do you disagree with the Company's representations?

A. I consider it naive that the Company assumes financial harm or higher costs for all if a jurisdiction, such as Washington, does not accept the prudence of every acquired resource acquired for the "system." I am perfectly willing to recommend revenue requirement levels to the Commission that enable the Company to recover the true costs to serve Washington. I have not suggested anything else in this proceeding. However, if one or more jurisdictions can be identified as causing the need for significant new incremental resources, then those jurisdictions should be expected to bear the costs of those resources. It is not correct to simply state that the Company or other jurisdictions will pay higher costs if complete sharing does not occur. Only if the jurisdictions causing the need for new resources are not willing to pay, does that possibility occur. On the other hand, if clear quantifiable benefits can be demonstrated for all customers, there may be a basis for some sharing in the cost of a resource, although the simple rolling-in of costs may not be proper. If a particular corporate strategy, such as increased wholesale market participation, is the driver behind resource acquisitions, there should not be cost pressures to other retail jurisdictions, unless they wish to share in the risks and benefits.

Q. Has the Company acquired other resources in addition to those reviewed in the Joint Report?

A. Yes. Since its 1999 general rate case, the Company has acquired the Gadsby and West Valley Projects. The costs associated with these resources are an issue in this proceeding. I discuss my recommendation regarding these resource additions later in this testimony. In addition, the Company is in the process of acquiring even more resources to meet load growth in Utah. Although these resources do not affect test year revenue requirements, the Company's Protocol proposal does set forth the manner in which the costs associated with these projects will be recovered. I believe it is appropriate to comment at this time on these more recent acquisitions given the inter-jurisdictional allocation proposal before the Commission in this proceeding, and the future allocation of those costs to Washington.

Q. What is important about the Company's recent request to defer excess power costs?

A. I believe that case is significant because the Commission recognized the simple facts that: 1) PacifiCorp's Washington operations have not been reviewed on a full general rate case record in over 17 years; and 2) the appropriate basis for inter-jurisdictional cost allocation of power costs has not been satisfactorily resolved. The Commission clarified that the Company's previous use of the so-called Modified Accord method did not justify its use in the deferral request proceeding. Those two issues were also fundamental in the Commission's order in that case authorizing the Company to file a general rate case prior to the end of the Rate Plan.

Q. Are there other events since the original merger of the Pacific and Utah systems that have affected power supply related issues?

A. Yes. It is appropriate to review some actions taken in other jurisdictions that have resulted in rate changes for the Company. For example, in 1989 after the acquisition of the Utah properties, the rates in Utah were significantly higher than rates in Washington. However, today rates in Utah are less than in 1989. All other jurisdictions have higher rates today than in 1989. Something is wrong. It makes no sense for the fastest growing jurisdiction to have lower rates today than prior to the merger. In fact, acquisition of new resources to serve load growth is the principle cause of rate pressure on any electric utility. The

Commission is well aware of the rate pressures new resources have upon the other utilities subject to its jurisdiction.

IV. COMPANY'S PROPOSED MSP SOLUTION OR "PROTOCOL"

A. Summary of the Proposed Protocol

Q. Has the Company identified general policy objectives that led to the filing of the Protocol and its proposed use in this proceeding?

A. Yes. Company witness Mr. MacRitchie describes several policy objectives, beginning with the commitment to implement SB 1149 in Oregon. The Company believes that it is important to have a platform in place that permits one or more of its jurisdictions to implement direct access without prejudicing customers in other jurisdictions. The Company is also striving to participate in an RTO in a manner that does not create undue risks for customers or shareholders and that takes into consideration the unique characteristics of the Western system. The Company is concerned about the potential for future wholesale market dysfunction and volatility, and desires to hedge those risks with a balanced supply portfolio, requiring long-term commitments by the Company. The Company is also concerned about the risk of generation shortages, as it believes few entities are prepared to construct new facilities. This concern, particularly for needs on the east-side of the Company's system, makes it critical, PacifiCorp claims, to be in a position to make major, long-term financial commitments with reasonable confidence to recover costs. The Company is also concerned with the process to address potential mergers and the allocation of subsequent merger benefits. Finally, the Company continues to address the perceived breakdown in the inter-jurisdictional allocation process.

Q. What benefits is the Company claiming for the customer if the Protocol is adopted?

A. The Company claims that customers will continue to receive safe and reliable electricity service at reasonable prices. The Company cites the need for additional generation and investments necessary for hydro reliceinsing and Clean Air Act compliance through 2014, claiming that adoption of the Protocol will permit the acquisition of new debt and equity financing to undertake these investments. In the event the Protocol is not adopted, the Company claims it may be required to rely upon shorter-term commitments that create exposure to price volatility and may not be least-cost.

Q. Generally describe the Company's Protocol.

A. The Company describes the Protocol as the tool for determining how its generation, transmission, and distribution costs will be allocated or assigned to PacifiCorp's six retail jurisdictions, as well as ensuring a continued dialog among interested parties regarding cost allocation procedures and disputes among the Company's jurisdictions. The testimony of Company witnesses Ms. Kelly, Mr. Duvall, and Mr. Taylor describe the basis and context of the "MSP solution" incorporated in the Protocol, as well as a detailed explanation of the various elements of the Protocol. The Company generally believes that the adoption of the Protocol will indicate that the Commission believes its terms are balanced, reasonable, and should be followed in future rate proceedings.

Q. Does the Company believe that adoption of the Protocol will be binding in future rate cases?

A. No. The Company recognizes that the Protocol's terms are not binding and that challenges will have to be addressed as they arise in future proceedings.

Q. Did the Company base its proposal on a set of principles?

A. Ms. Kelly states that a resolution to MSP issues should:

- promote economic efficiency;

- be equitable to PacifiCorp's customers and shareholders;
- allow individual States to pursue policy initiatives without burdening customers in other states;
- permit continued effective oversight; and
- not impede the provision of safe, adequate and reliable service by the Company.

Q. According to PacifiCorp, how does the Protocol address economic efficiency?

A. The Company claims it will continue to plan and operate its system on an integrated basis. The Protocol is more of a ratemaking procedure that should not create inappropriate incentives for efficient system planning or operation.

Q. Where is the principle of cost causation considered?

A. Ms. Kelly states that, from a customer perspective, the Company believes the Protocol will "cause each State to reasonably support the costs they are imposing on PacifiCorp's system." (Exhibit No.___ (ALK-1T), at 4). The Company claims that this is carried out through the various allocation factors that underlie the Protocol, in addition to the identification and allocation of what are to be called "Seasonal Resources."

Q. How does the Company contend that the Protocol addresses shareholder interests?

A. The Company contends the Protocol is equitable because affords the Company a reasonable opportunity to recover 100 percent of its prudently incurred costs, without any short-fall arising from inter-jurisdictional cost allocation methods.

Q. How does the Company claim the Protocol accommodates individual state policy initiatives?

A. Ms. Kelly identifies several policy initiatives that the Company believes can be pursued without burdening the customers of other states. These include:

- adopting a direct access program;
- investing in Demand Side Management Programs;
- adopting portfolio standards;
- adopting Industrial customer discounts supporting economic development;
- investing in hydro-electric facilities to enhance the surrounding environment and fish habitat; and
- allowing Oregon to opt-out of a future major coal-fired resource.

Q. How does the Company claim that the Protocol permits continued effective regulatory oversight?

A. The Company claims the Protocol does not depart significantly from past allocation practices. It incorporates elements of the "rolled-in" method that has be adopted in Utah, as well as a form of hydro-endowment. The Company also states that an extraordinary level of analysis supports the Protocol.

Q. How does the Company claim that the Protocol enhances the Company ability to provide safe, adequate, and reliable service?

A. The Company claims that the Protocol will permit it to make needed, cost effective investments in resources and transmission with a reasonable degree of confidence that it will recover 100 percent of prudently incurred costs.

Q. When is the Company expecting the Protocol to be adopted for rate proceedings?

A. Beginning with all rate proceedings initiated subsequent to November 1, 2003. There is no stated termination date. The Company does recognize that adoption of the Protocol will not bind future Commissions or bar other parties from challenging inter-jurisdictional cost allocations in future rate proceedings.

Q. What proceedings are pending in other PacifiCorp jurisdictions regarding the Protocol?

A. The Company has made MSP-related filings in Idaho, Oregon, Utah, and Wyoming, with a California filing expected later this year. The Washington filing is the only one made in conjunction with a general rate case. Later in my testimony I discuss other relevant filings that have been made by the Company.

Q. Returning to the description of the Protocol, can you briefly summarize the most relevant features of the Protocol?

A. I have reviewed the features of the Protocol. Exhibit No.___ (APB-2) contains my summary of the most relevant features.

B. Company's MSP Analyses and Support for Protocol

Q. What analyses has the Company provided in support of its Protocol?

A. The Company's support for the Protocol is described in the testimony of Company witness Mr. Duvall, who provides background information on system operations and associated modeling tools, as well as a summary of key analytical findings with respect to the "Dynamic" and "Hybrid" allocation proposals discussed during the MSP.

Q. According to the Company, why is a description of PacifiCorp's system important to inter-jurisdictional allocations?

A. Mr. Duvall states that transmission and generation costs, as differentiated from distribution costs, are incurred to produce and move bulk power to the local points of distribution across PacifiCorp's entire system. Mr. Duvall describes the number of customers spread out over six states, the number and capacity of generating facilities, and the miles of transmission lines with over 125 points of interconnection. He also identifies the presence of numerous wholesale purchased power contracts and wheeling contracts. Mr. Duvall goes on to state that the Company is limited by transmission constraints, and operates its system on an integrated basis with two control areas. He admits that cost allocation issues are much more complicated because the system has some attributes of both a single system and two separate systems serving two regions.

Q. Please summarize how the Company operates its system.

A. The Company claims resources are dispatched to minimize total Company costs on a six-state integrated basis. The system is separated into two control areas, generally referred to as the East Control Area and the West Control Area, which both contain the generating resources owned by Company.

Q. Why does the Company operate two control areas?

A. According to the Company, it is not practical to operate as a single control area due to limited transmission rights between its West and East Control Areas. In addition, the Company states that, while it may be technically feasible to do so, operating the system as one control area would require additional consultation with neighboring control areas as part of a NERC certification process. The system would then be operated in the same manner as it is today, even with one control area.

Q. How limited are the transmission rights between the West and East Control Areas?

A. In Exhibit No.___ (GND-2), the Company presents a transmission topology map to indicate modeled transfer capability between various bubbles representing load and generation centers. The topology map clearly shows the limited transfer capability between the East and West Control Areas. The capability between Jim Bridger and the Wyoming bubble is limited in getting power from East to West because the path from Jim Bridger to Idaho is dedicated for power from Bridger, a Westside resource. The main path from East Main to Mid-Columbia is relatively limited. The Company states it is able to purchase non-firm transmission on an as needed basis to enhance system integration. The amount of modeled interconnections can also be put in context of Company-owned control area generating resources—approximately 4900 MW total capacity in the East and 2800 MW total capacity in the West, not including recently announced projects.

Q. How does the Company claim to operate its system to benefit all customers?

A. The Company claims there are several ways that resources added in one control area can provide benefits to the other control area. This claim appears is based on the simple statement that:

> PacifiCorp will continue to plan and operate its generation and transmission on a six-state integrated basis in a manner that minimizes costs to all its retail customers. This allows the Company to locate a power plant in one control area to meet load requirements in the other control area if that is the least-cost, least-risk option for the total system. *(Exhibit No.___(GND-1T), at 6).*

In addition, the Company states that cross-control area exchange contracts allow power to be delivered in one area and returned in another, effectively transferring power without requiring transmission.

Q. Mr. Duvall provides a summary of the MSP analytical process that was carried out in 2002. What is the purpose of this testimony?

A. I believe it provides background information leading up to the Company's decision to file its Protocol proposal.

Q. How does the Company characterize the 2002 MSP analytical process?

A. Mr. Duvall describes how, during this period, the Company provided initial briefings to a workgroup of MSP participants covering what analytical methods and tools were available, ultimately providing copies of the Company's GRID model and the computers necessary to run it to key parties in each state. Generally, over this period the MSP workgroup discussed studies to be run, specific analytical issues, and the results of completed studies.

Q. What studies were carried out during this period?

A. The Company compiled a list of 56 studies that were proposed for consideration by the workgroup. Not all the studies were completed, as some requests were withdrawn or replaced by others. The Company used a revenue requirement forecast model to determine the 15-year revenue requirement affect of the various studies completed. It is this model that actually calculates individual state impacts using the total system net power costs as determined by the

Company's GRID model as input. Although there was a series of data updates, the revenue requirement forecast model largely incorporated the results from the Company's 2003 Integrated Resource Plan for purposes of assumed resource additions and other estimated resource related costs. An updated IRP has subsequently changed many load growth assumptions, particularly the need for Westside resources versus Eastside resources. The process also included the use of two separate studies as the standards for comparison. Mr. Duvall briefly summarizes some of the many studies, as well as a more detailed discussion of the "Dynamic" and "Hybrid" models that were ultimately identified as the two allocation proposals that drew the most interest.

Q. Please describe the Dynamic model.

A. This model is based on the "rolled-in" allocation method recently adopted by Utah, where states pay for a share of all Company resources, including Pacific Northwest hydro, based on demand, energy, and other factors. A state's share would change over time as the characteristics of its load changes. For example, if Utah were to grow at a faster pace than the other states, it would begin to be allocated an increasing share of Pacific Northwest hydro resources (as well as other Company resources). There would be no distinction between existing and new resources regardless of for whom the resource was acquired or whether any energy could actually be delivered.

Q. What issues did the parties raise regarding this model?

A. The parties identified the effect of increasing load growth, and the allocation of Pacific Northwest hydro resources as issues. They also were concerned about the ability of the proposal to address different state policies regarding types of new resources, as well as direct access programs.

Q. Please describe the Hybrid model.

A. To the degree possible, the Hybrid proposal separates PacifiCorp's system into two regions for purposes of cost allocation. The regions generally reflect the two control areas of the Company. Specific resources are identified and assigned as serving each region, mimicking the way the system is operated in large part. An interchange accounting method allows recovery of, or accounts for, the benefits of power delivered between the two regions.

Q. What issues did the parties raise regarding the Hybrid model?

A. Some parties expressed concerns regarding the initial assignment of resources. The Company claims that even the proponents could not agree on an appropriate resource assignment. Some parties feared that the proposal would lead the Company away from integrated least-cost planning or would reduce fuel type diversity. Some also expressed concerns that the interchange accounting method would complicate the regulatory process. These concerns largely came from those jurisdictions clearly not interested in exploring this model further. Washington Staff did not share many of the concerns, and expressed a desire to continue to work with the Hybrid model.

Q. How does the Company characterize the 2003 MSP analyses discussed in Mr. Duvall's direct testimony?

A. The 2003 MSP analyses focused on the Hybrid and Dynamic allocation proposals. Mr. Duvall presents the overall revenue impact of the Hybrid proposal in Exhibit No.___ (GND-3). The graph shows the difference in forecast "Westside" revenue requirements as compared to the "Modified Accord" allocation methodology, and the difference in forecast "Eastside" revenue requirements as compared to the "Rolled-in" allocation methodology. The Company claims that on a present value basis, the overall impact is modest, with all states seeing small increases as the allocation "hole" is closed.

Q. What other analyses model did the Company undertake?

A. The Company performed an analysis that was intended to identify various risks, given a number of scenarios the different jurisdictions might face under the Dynamic and Hybrid allocation proposals. Scenarios included such events as losses of load, different resource additions, water conditions, a major resource outage during a period of high gas and market prices, and changes in gas and electric market prices. Depending on the scenario chosen and the assumptions made, each region (West and East) had varying cost increases or decreases. The Company concluded that there was greater risk under the Hybrid proposal than the Dynamic proposal. Mr. Duvall summarizes the results of the studies on pages 14 and 15 of his testimony, Exhibit No.___(GND-1T).

Q. Does the Company's risk analysis address a particular region's or state's willingness to accept the risk associated with the Hybrid or Dynamic allocation proposals?

A. No. Neither does the supporting testimony of the Company's witnesses.

Q. What other issues related to the two proposals does the Company discuss?

A. The Company raises the issue of load growth consequences and compares revenue requirement forecasts using the two proposals. Based on the study described, the Company concludes, that on balance, the Dynamic proposal limits the impact of a faster growing state's load growth just as well as the Hybrid proposal. Mr. Duvall explains why PacifiCorp believes the Dynamic proposal does not, in the case of faster Utah growth, result in a material unfair subsidy to Utah from customers in western states. (Exhibit ___ (GND-1T, at 17-18). He also mentioned that any subsidy that might exist under the Dynamic allocation method would be mitigated by the Protocol's proposed use of seasonal resources. *Id.* at 18.

Q. The Company describes how Westside resource costs may increase faster under the Hybrid proposal than under the Dynamic proposal. What is your reaction to this?

A. The Company described several scenarios that would result in cost pressures to the Westside. They include increases in the embedded cost of Westside resources, presumably from hydro re-licensing costs, as well as the need to replace existing low cost wholesale contracts. The Company only concludes that the impact of these increased costs is not much different under the Hybrid or Dynamic proposals. This conclusion only serves to reinforce Staff's concern that the MSP is entirely results driven. I see no problem with cost pressures for the

Westside if the Westside is causing these costs. However, I have trouble with addressing cost pressures by shifting those costs to other states.

Q. Does the Company address a particular region's or state's willingness to accept the revenue requirement risk associated with increased resource costs, including re-licensing, to be assigned to it under the Hybrid proposal?

A. No.

Q. The Company also analyzed the impact of loss of load in each of its two control areas and the revenue requirement impact of that under the Hybrid and Dynamic allocation methods. How do you respond to this?

A. The Company assumed a one-year loss of load allocated under both the Hybrid and Dynamic proposals, concluding that such a loss has almost no impact in other states under either proposal. The Company then explains that this conclusion is made possible because both control areas can work together to reduce generation in response to load loss. This in turn supports the claims that the control areas are not totally isolated from one another and that there are no operational reasons to assume that benefits added to one control area do not benefit the other control area.

Q. Did the Company continue to evaluate the Hybrid proposal for ultimate use in this proceeding?

A. Not to Staff's knowledge. Once the initial MSP meetings ended, no further attempts were made by the Company to include Washington Staff in the refinement of the Hybrid proposal for purposes of a MSP solution.

C. Staff's Evaluation of the Protocol

Q. Please describe the overall context in which you evaluated the Protocol.

A. I carried out my evaluation of the Company's proposed inter-state allocation on two levels. The first level addresses the more general questions, such as:

- How the various MSP proposals were evaluated and how the Protocol proposal was derived?
- Does the Protocol satisfy the basic principles set forth by Staff in the MSP?
- How does the Protocol meet certain objectives set forth by Staff for purposes of evaluating power supply costs in this proceeding?

The second level addresses the more specific Protocol features and whether they result in the fair and principled allocation of prudently incurred costs to Washington.

Q. What concerns do you have regarding how the various MSP proposals were evaluated and how the Protocol was derived?

A. I continue to be concerned that other parties to the MSP, including the Company, have inappropriately used results-based, scenario analysis in evaluating and ultimately supporting the various proposals. More specifically, the primary emphasis of many parties' analyses was how the individual state's future revenue requirements may be affected by the various allocation methods, rather than how the methodology best addresses a set of principles.

Q. What is the problem with basing inter-state allocation recommendations on studies of future revenue requirements?

A. My concern is that those results or outcomes will drive the allocation method that is supported by a particular party, rather than a set of principles. This clearly has been the case for the Company in this proceeding. For example, Mr. Duvall presents the Company's analysis of the 2003 MSP process. He discusses the results of the Company's analysis of the Hybrid and Dynamic allocation proposals by making a revenue requirement comparison for the period 2004 through 2018 in Exhibit No.___ (GND-3). He also describes the risk analyses included in Exhibit No. ___(GND-4), which compares future risks between the

Hybrid and Dynamic proposals based on a number of scenarios and sensitivities. Mr. Duvall states:

> The analyses were intended to highlight situations in which customers in specific States might face different risks under the Dynamic Proposal than under the Hybrid proposal. *Exhibit ___ (DNT-1T), at 13.*

In its analyses, the Company considered scenarios including losses of load, responses in new resource additions, water conditions, outages, market prices, and load growth. As a result of these studies, the Company draws certain conclusions regarding the cost risk for the different jurisdictions.

Q. Please comment on the results of the Company's risk analysis?

A. The results of a risk analysis, such as that carried out by the Company, should have no bearing on the cost allocation method chosen. While the 2003 MSP analysis discussed by Mr. Duvall may be interesting from an academic viewpoint, inter-jurisdictional allocations should be based on a set of principles, not whether Washington (or another jurisdiction) is better or worse off 15 years into the future if load loss occurs, market prices vary, different future generating plants are added, or if load growth occurs in Utah. The presence, or lack of sensitivity to various "what if" scenarios should not form the basis for to favor one allocation methodology over another. The entire section of Mr. Duvall's testimony from page 13, line 9, through page 20, line 12, is irrelevant, as is Mr. Duvall's summary conclusion of the analyses comparing the Hybrid and Dynamic allocation proposals. (*See* Exhibit ___ (GND-1T), at 13, lines 12-15).

Q. Are you concerned about the revenue requirement effects of the various allocation proposals?

A. I am concerned. However, I believe that the ultimate recommendation of inter-state allocation alternatives should not be based on minimizing the revenue requirement affects of different allocation methods for Washington, or any other jurisdiction. The objective should be to recommend a methodology that can be used to fairly identify the prudently incurred costs to serve Washington customers. I am ready and willing to recommend that Washington customers absorb the risks associated with Washington operations, when a principled inter-jurisdictional allocation methodology is adopted. However, I cannot recommend shifting to Washington costs or risks caused by other jurisdictions or costs that cannot be demonstrated to be caused by Washington operations simply because a risk study shows a "modest" impact.

Q. Are the Company and other parties to the MSP aware of Washington Staff's concerns?

A. Yes. As earlier as September 2002, Staff stated its concerns that parties negotiating from outcomes will unlikely reach agreement, and that principled agreements are reached from principled positions. Staff also stated that it would be willing to accept some scenarios and sensitivities even though they may not be the best for Washington, if they resulted from principle. In other words, Staff was willing to take the risk and accept the outcome from a principled position on hydro benefits.

Q. Do your concerns extend to the MSP proceedings that are presently ongoing in other jurisdictions?

A. Unfortunately yes. Staff is following those proceedings to the extent possible. Reviewing data requests from the parties in the various jurisdictions leads Staff to conclude that an outcome-based decision process continues to be the norm.

Q. Are you saying that recommendations by the various parties in the MSP proceedings will only be influenced by the results of the numerous scenarios?

A. No, I cannot say that for sure. I can only say that Staff is concerned given the various parties continued penchant for multi-year, multi-state, scenario oriented analyses.

Q. Did Staff ask for any additional modeling to be carried out in this proceeding?

A. Staff asked the Company to recast its Washington revenue requirement based on the Hybrid inter-jurisdictional cost allocation methodology discussed in the testimony of Mr. Duvall (Exhibit No.___(GND-1T)). This request was for the Company's Washington jurisdiction only and only for the test year ending March 30, 2003. In response to Staff Data Request Nos. 4 and 213, the Company recast two options, one with transmission allocated on a system basis, such as in the Protocol, and the other with transmission allocated based on control areas.

Q. Why is it not in the public interest for Washington to base inter-jurisdictional allocation recommendations on future risk analysis and scenario modeling?

A. Because an unprincipled solution is not sustainable in the long-run. Early in the MSP proceedings, Washington Staff expressed little confidence that other parties could count on the outcome-driven parties to live up to their agreements when the outcomes turn out less beneficial than expected. As late as July 15, 2003, toward the end of the MSP, Staff indicated that it would only support: "a principled, reasonable, and fair allocation of resources in Commission proceedings," and that the Company must present: "an allocation method that satisfies our fundamental principles, and that has a solid technical, analytical and physical foundation." *See* Washington's Open Statements for July 15-17, 2003, MSP Meetings.

Q. What other issues do you have regarding the Company's ultimate choice for the MSP Solution, or Protocol?

A. The Protocol, in large part, is based on the results of the Company's 2003 MSP Analyses, which (as discussed earlier) compared the future revenue requirement effects of the Hybrid and Dynamic allocation proposals under various scenarios. The Protocol is primarily based on the Dynamic or "rolled-in" allocation methodology currently used in Utah, with a few carve-outs to address some specific concerns of some of the other parties. The Company does not provide a clear explanation of why a control area-based allocation methodology was not adopted. It relies upon conclusions that the impact of the Hybrid model on overall revenue requirements is "quite modest" as compared to the Dynamic proposal and that, under the Hybrid approach, there is "greater risk" for various parties under a number of generation and market price sensitivity studies. The Company also admits that the Hybrid proposal largely insulates the states in the

Westside from the impact of load growth in Utah. However, the Company then tries to address the burden of load growth in Utah on the Westside states by saying that future Westside costs would increase at a faster rate under the Hybrid approach than under the Dynamic proposal. The Company claims this result is counter to expectations, somehow concluding that the Dynamic proposal does not result in a "material unfair subsidy to Utah from customers in the Western states." This just further demonstrates that the Company's choice of allocation methodologies is driven by a results-based analysis with the goal of smoothing future revenue requirements for all, rather than identifying who is causing the cost increases and insuring that they are allocated the costs. The Company's use of the Dynamic or "rolled-in" allocation methodology as the basis for the Protocol continues this unprincipled approach.

Q. Is it appropriate that the different regions under a control area-based allocation methodology, have different rates of cost increases?

A. Yes. It is entirely appropriate (and likely) that different regions will experience different cost pressures. Washington customers should pay rates that reflect, as directly as possible, the identifiable costs incurred to serve them. If there are cost pressures due to hydro re-licensing, new Mid-Columbia contracts, load growth, or events such as regional droughts, and those costs were prudently incurred to serve Washington, then Washington ratepayers should be responsible for the recovery of those costs. Prudently incurred costs are those costs that can be demonstrated as necessary to serve Washington load, are acquired in the appropriate manner, and represent demonstrable least-cost options for Washington and the region. It is irrelevant whether these costs occur at a greater or lesser rate than another region. This concept also insures that customers see the appropriate signals related to the cost necessary to serve them.

Q. Should the other jurisdiction be encouraged to pay their costs?

A. Yes. The same philosophy should exist for other regions and jurisdictions. Staff continues to question the wisdom of not sending accurate price signals to the customers in the Eastside and the impacts these loads have on the Company's costs. Without proper price signals, many alternative least cost options (e.g. demand-side management) may not be developed. For example, the Company has recently announced the intent to acquire two large generating resources, the 525 MW Current Creek project and the 534 MW Lake Side Power Plant, in its Eastern Control Area. Those customers causing the need for the new facilities should bear the costs and see the prices that are associated with these new resources. The principal goal of an inter-state allocation methodology should not be to simply "roll-in" costs so that there can be a smoothing of revenue requirements between regions. This is particularly true if the regions have different load characteristics and resource bases. Claims of resource diversity are not, by themselves, cause for rolling-in new resource costs.

Q. Does the Protocol satisfy the basic principles set forth by Staff in the MSP?

A. The Protocol addresses some of those principles. However, it also falls well short on others.

Q. What are the principles presented by Washington at the MSP meetings?

A. The principles are:

- Each state commission should regulate PacifiCorp and serve the public interest in accordance with its individual state statutory authority;
- Allocation methods should preserve each state's jurisdiction to regulate PacifiCorp in the public interest;
- Allocation methods should allow each state to independently pursue energy policy;
- On a going-forward basis, PacifiCorp should have a reasonable opportunity to recover from cost-causers its prudently incurred costs;
- Cost and benefit allocations should be guided by the principles of cost and benefit causation, fairness, and equity;

- To the maximum extent practicable, costs and benefits should be directly assigned;
- Result of the multi-state process should be sustainable, long-term, and robust;
- PacifiCorp should prepare resource plans on both an integrated system-wide basis and an individual state basis; and
- PacifiCorp should operate and provide electricity to each of the six states in a reliable and sustainable manner consistent with the laws and regulations of each state.

Q. Does the Protocol allow each State Commission to regulate and serve the public interest in accordance with its individual state statutory authority and to independently pursue energy policy?

A. In general, yes. However, this is a double-edged sword. The Protocol does nothing to resolve conflicts between states in defining what the "public interest" entails. What is in the public interest for one jurisdiction may be not in the public interest of another. While not precluding a jurisdiction from implementing its statutory duties, the Protocol allows the decisions of one state to affect those of another. Under a rolled-in allocation methodology this may occur. For example, to satisfy an aggressive approach to address increased load growth and to enhance the economic development in a particular jurisdiction, the Company may choose to build a large base-load thermal plant. Under the Protocol, the de-facto treatment of this plant as a System Resource allocates the cost to all jurisdictions. Another state may chose to meet load growth with aggressive demand-side management programs or with renewable resources. Although that state is not precluded from developing such programs under the Protocol with situs allocation, it would be allocated costs of the large thermal plant. Another example is the acquisition of a peaking facility to meet the specific needs of one jurisdiction. Under the Protocol, this resource would be classified as a Seasonal or System Resource and allocated to all jurisdictions. Another jurisdiction may choose to meet its incremental peaking requirements, if any, with other alternatives, yet it is expected to share in the cost of the new peaking facility. A more obvious scenario is the use of special contracts or tariffs to implement economic incentives to certain customers. Under the Protocol it is the "local" commission that determines if an offered rate is appropriate. The state charged with developing a discounted rate is also the jurisdiction determining whether costs should be shared by the other states. Clearly discounts, incentives, or special rates deemed appropriate by one commission may not be deemed so by other commissions, particularly those that are precluded by statute from offering economic development rates. So while the Protocol does not preclude each jurisdiction from regulating the Company and serving the public interest in accordance with its particular statutory authority, its does not isolate the other jurisdictions from those decisions.

Q. Under the Protocol, does the Company have, on a going forward basis, a reasonable opportunity to recover from cost-causers its prudently incurred costs?

A. The Protocol continues to result in costs caused by one jurisdiction being spread to other jurisdictions through the rolled-in methodology. This is true for both Seasonal and System Resources. The Protocol makes no explicit distinction between cost causers. It simply assigns a portion of the costs to all jurisdictions based on load characteristics. The Company is indifferent as to who actually pays the costs, as long as the Company recovers its total costs. The extent that the Company can recover costs from cost causers is a function of their willingness to present and support a principled cost allocation methodology. Based on recent events, that does not appear to have been the case. However, Washington customers should not be considered the "place of last resort" for recovering costs that other jurisdictions, through adoption of various allocation schemes, refuse to pay.

Q. Are the Protocol's features guided by principles of cost and benefit causation, fairness, and equity?

A. No. This where the Protocol fails any test. Although some aspects of the proposed allocation methodology (such as the hydro-endowment) address some specific issues, the majority of the Protocol relies upon methodologies for which consensus was never reached in the MSP. As discussed earlier, the use of an allocation methodology based on rolling-in incremental resources is more the result of smoothing jurisdictional revenue requirements rather than an attempt to match costs to those customers actually causing the costs. As I have stated many times, under the Protocol, Washington is allocated, or will be allocated, a share of peaking (Seasonal Resources) and base load (System resources) resources that have recently been acquired specifically to meet load growth in Utah. I will discuss specific issues related to these acquisitions later in my testimony. Significantly, these acquisitions were not acquired contemporaneously with any resource acquisition Request for Proposals submitted or filed in any jurisdiction in the Western Control Area. In fact, the Company has maintained that it was not necessary to file an RFP in Washington because it contended that no additional resources were required. (Docket No. UE-031311, PacifiCorp's Request for Waiver of RFP Filing Requirement, (Jan. 2, 2004)).

Q. Is the Protocol fair and equitable in regards to inter-state allocations?

A. No, for the same reasons I gave earlier regarding cost causation. It is also difficult to determine how such Protocol features as the Oregon coal plant opt-out provision are fair and equitable. Is it appropriate that the Protocol contain specific provisions to address broad concerns that Oregon policy makers and customer representatives have made in regard to the environmental consequences of coal plants? There is no consideration of policy concerns that interested parties in other jurisdiction might have. I am confident that other states share similar concerns, however, no specific opt-out provision has been included for other jurisdictions. The Protocol also ignores the fact that Washington, as well as other states, effectively have an existing "opt-out" feature. For example, in Washington a prudence determination is required before the costs associated with a new resource can be recovered in rates. This includes consideration of environmental and other consequences. I strongly disagree with the Company's contention that:

> The Protocol does not require that we demonstrate a "state-specific" benefit for particular resources before they can be recovered in a particular state's retail rates. (*Exhibit No. ___ (MTW-1T, at 21, lines 5-7*).

As discussed earlier in my testimony, it is entirely possible that the Company can prudently acquire a resource that is not appropriate for recovery in the rates of every jurisdiction. There must be specific showing that Washington customers are responsible for resource costs before they are allocated a portion of the costs. This is entirely consistent with the Commission's Order in Docket Nos. UE-020417 and UE-991832, in which PacifiCorp was denied recovery of certain extraordinary costs, in part because of a failure to show that any of the costs should be allocated to Washington customers.[5] The same standard applies for resources acquired by the Company, resources that represent hundreds of millions of dollars in costs to be allocated to the different jurisdictions. When asked in a data request whether the Company has the responsibility to demonstrate benefits for all its customers resulting from a resource acquisition, the Company simply states that:

> The Company plans and operates its system on an integrated basis to capture the efficiencies of the system. System resources are acquired consistent with the Company's Integrated Resource Plan (IRP) and contemporaneous cost/benefit analyses. Washington customers receive the benefit of low-cost resources through the cost allocation process based on its share of system loads. (*PacifiCorp Response to Staff Data Request No. 20*)

[5] *In re the Petition of PacifiCorp d/b/a Pacific Power & Light Co. For an Accounting Order Authorizing Deferral of Excess Net Power Costs, et al*, Docket Nos. UE-020417 & UE-991832, Sixth Supplemental Order Denying Petition for Accounting Order; Rejecting Tariff Filing; Authorizing Subsequent Filing, ¶ 32 (July 15, 2003).

This continues to be the Company's support for rolling-in costs to Washington customers.

Q. Is this statement sufficient to warrant recovery of millions of dollars in resource costs by Washington customers?

A. No. Staff continues to look for analyses that would support the Protocol's treatment of resource costs that Washington customers would be expected to bear. Staff has repeatedly asked for studies, analyses, and documents supporting the Company's claims that various resource acquisitions benefit Washington. The Company's response continues to be broad statements on how it plans and operates its system on an integrated basis to capture efficiencies that benefit all customers. PacifiCorp contends that Washington customers benefit from these efficiencies based on their share of system allocated resources. (PacifiCorp's Responses to Staff Data Request Nos. 20, 22, 25, and 30).

Q. Has the Company quantified these benefits for Washington?

A. No. Nor, as discussed earlier, has the Company recently pursued resource acquisitions for its Western Control Area, other than for specific wind resources. The Company therefore even lacks an appropriate benchmark for determining just what benefits may exist for Washington as compared to other alternatives.

Q. Is the Protocol fair and equitable?

A. No. The Protocol does not allocate costs in a fair and equitable manner.

Q. Does the Protocol result in maximizing the direct assignment of costs and benefits?

A. The Protocol generally limits the direct assignment of costs to resources assigned as "State Resources" and for distribution system costs that can be situs assigned. Other than those costs, no provisions provide for the allocation of cost specifically to the jurisdiction that can be identified to have caused the cost. The Protocol makes no attempt to make such a determination and simply continues to roll-in those costs that are incurred.

Q. Is the Protocol sustainable, long-term, and robust?

A. The Protocol is not sustainable. Nothing in the Protocol leads me to conclude that state commissions will not continue to adopt the most favorable allocation methodology for their states in the event the Protocol does not provide the expected results

Q. Have your concerns been confirmed by more recent events regarding the MSP as a whole?

A. Yes. The recent filing of a Revised Protocol in Oregon and the draft Utah Revised Protocol only serve to confirm that any non-principled approach to inter-jurisdictional cost allocations is not sustainable. I will discuss the Oregon filing in more detail later in my testimony.

Q. Does the Protocol address resource planning?

A. The Protocol does not explicitly address resource planning. It does provide for the situs assignment of Demand-Side Management Programs and the potential for situs assignment of costs associated with Portfolio Standards that may be adopted by the states. Other than those costs, the Protocol simply states that the Company will continue to plan and operate its generation and transmission system on a six-state integrated basis in a manner that minimizes total system costs to its retail customer. The Protocol presumes that all new generating resources will be assigned as either Seasonal Resources or System Resources, both allocated on a rolled-in basis, using various allocators. The Protocol does not provide for the direct assignment of costs for resources acquired to meet the growth of a specific jurisdiction, or even control area. This Commission, in its letter acknowledging the Company's 2003 Least Cost Electric Plan, encouraged the Company to consider multi-area modeling in order to account for region-specific resources and constraints. Any principled inter-jurisdictional cost allocation proposal should be sufficiently flexible to incorporate potential differences in resource acquisitions brought about by state specific concerns in the least cost planning process.

Q. Returning to how the Protocol addresses your general concerns, please summarize Staff's objectives in this proceeding from a power supply perspective.

A. Staff's primary objective is to determine a fair and principled allocation of power supply and transmission costs for PacifiCorp's Washington operations, taking into consideration the burdens placed on the Commission to do so. More specifically, the objective is to evaluate the prudence of the Company's recent resource acquisitions, determine Washington allocated Net Power Cost, and determine the appropriate level of fixed-costs for both power supply and transmission resources. This evaluation should be carried out in the context of inter-jurisdictional allocation methodology that is principled, in the public interest for Washington ratepayers, and results in a fair share of the Company's costs to be recovered from Washington customers. The inter-jurisdictional cost allocation method must facilitate the ability of this Commission to determine the appropriate power supply and transmission costs related to serving Washington.

Q. Why did you raise the issue of administrative burden in the context of determining the Washington allocated Net Power Cost?

A. PacifiCorp presently operates in six states and is subject to the jurisdiction of six commissions, as well as the FERC. The Company is also owned by a foreign entity, Scottish Power. Washington's retail customer account for approximately 8 percent of total customers with approximately 8.5 percent of the total Company load. Given these characteristics, Staff is interested in making the determination of Washington rates as administratively efficient as possible. The Company is experiencing different load growth characteristics in its various jurisdictions as well as divergent state regulatory policies. The Company's priorities appear to be elsewhere – Oregon to address direct access requirements and Utah to address increasing resource needs. After months of effort there has not been consensus in the MSP. In fact, there are now other versions of the Protocol before the various state commissions. The Company has acquired resources that may not be appropriate, or even required, to serve Washington, yet all of the proposed allocation methodologies result in Washington customers absorbing a portion of those cost. These facts have led me identify administrative burden as an important issue in this proceeding.

Q. What other administrative burdens are there?

A. Staff's concern is not limited to the effects on Washington allocated costs. All of the Protocol versions contain features that would require Staff, in order to protect Washington customers, to participate in various evaluation processes for resources that may have been specifically acquired for needs outside Washington. Given those very real concerns, Staff is interested in allocation methodologies that facilitate the review of costs to serve Washington operations yet provide rates that are fair, just, reasonable, and sufficient.

Q. Why are resource additions a particular problem?

A. As stated earlier, it has been a while since this Commission has reviewed the Company's costs in a full general rate case record. The recent power crisis, and other events, have only served to reinforce Staff's belief that the ability to effectively identify power supply and other costs incurred specifically to serve Washington customers is a vital issue in this proceeding.

Q. What issues were brought about by the power crisis?

A. During periods of the crisis, the Company was exposed to high power costs to meet certain customer load requirements. The Company attempted to recover a portion of those increased costs from Washington customers. The Commission denied the Company immediate rate relief and the deferral of claimed excess power cost in Docket UE-020417, based on its conclusion that the Company had failed to show that any of the increased costs should be allocated to Washington. The effect on the Washington allocated Net Power Cost from factors such as load growth and resource acquisitions is fundamental to this proceeding. This includes the ability to identify those resources that are necessary serve Washington, while protecting Washington customers from costs that are caused by others.

Q. What are the other events that are of concern to Staff?

A. Since its last general rate case, the Company has acquired several major resources. Many of those resources are the subjects of the Joint Report contained in Exhibit No.___ (MTW-4). While the Joint Report reaches the conclusion that the resources have been acquired prudently from a system-wide perspective, the Company must make a showing that the resources were acquired prudently to satisfy increased load growth or demand in Washington before they may be included in rates. In addition, the Company has acquired the Gadsby and West Valley projects in the Salt Lake City area, and is presently moving forward with construction of another Utah Valley plant known as the Current Creek Project, a project with questionable benefits to Washington customers. The Company's Board has also recently announced its approval to proceed with yet another generating plant in the Salt Lake City area called Lakeside. The Protocol, and other revised versions, would result in the allocation of a portion of the costs for all of these projects to Washington, based on rolling-in of costs.

Q. Are you suggesting that Washington customers not bear their fair share of power supply costs?

A. Absolutely not. I simply contend that Washington customers should bear their fair share of those power supply costs that can be specifically identified as necessary and appropriate to serve Washington operations. As stated earlier in my testimony, resources may be prudently acquired to serve system requirements but not appropriate to be recovered in all jurisdictions.

Q. Can you elaborate on your concerns regarding the administrative burden of evaluating resource acquisitions under an inter-jurisdictional allocation

methodology that automatically allocates a portion of new resource costs to all jurisdictions?

A. Such an allocation methodology requires Washington to evaluate each resource acquisition for prudence before those costs can be recovered through rates. To facilitate this review, Washington, as well as the other jurisdictions, should be involved not only in the Company's least cost planning process, but also the RFP process, the bid and bid review process, as well as the actual acquisition or construction phase of the process. Washington must undertake this review even for a resource that was specifically identified and acquired to meet load requirements in a completely different control area. The Company's recently acquired and announced projects are not minor expenditures. They amount to hundreds of millions of dollars in total costs to the Company and its customers. There is a clear administrative burden under the Protocol in order to protect Washington customers. The evaluation of any inter-jurisdictional cost allocation proposal, with the public interest of Washington customers in mind, must consider the burden of the effected parties to evaluate the costs.

Q. How will Staff's objective to address overall administrative burden affect your analysis of inter-jurisdictional cost allocations?

A. I am looking for methodologies that will clearly allocate costs to those jurisdictions that can be identified as causing the costs. This is nothing more than recognizing traditional "cost causation" principles. An example may be a generating facility that has been identified and acquired to meet the load requirements of a specific jurisdiction or control area. Unless there are clear and quantifiable benefits to others states, the costs associated with the resource should be recovered from the jurisdiction or control area identified as needing the power.

Q. Are there other factors that can create burdens?

A. Yes. Wholesale sales are a substantial portion of PacifiCorp's overall energy sales. In fact, information suggests that some Company resources have been acquired primarily to serve that market. Traditionally, retail customers are allocated the cost associated with resources, and are then allocated their portion of the revenues. To protect retail customers, these arrangements should be examined with an appropriate balance between the risks of the resource and the benefits provided. A jurisdiction may not wish to accept the risks and rewards of such transactions and customers should, therefore, not be allocated costs through some inter-jurisdictional cost allocation scheme that allocates any resource to all jurisdictions.

Q. Are there other objectives to consider in evaluating the proposed Protocol?

A. Yes. It is important to point out that Staff is focused on setting rates in this proceeding based on the test year and pro-forma period identified. Staff's evaluation and recommendations, particularly regarding inter-jurisdictional cost allocations, are based on principles previously identified in the MSP. Staff is not evaluating proposals on the basis of how a particular allocation methodology "performs" into the future, such as the Company and other parties in the MSP appear to favor.

Q. Does the Protocol, as filed in Washington, meet Staff's objectives for evaluating power supply and transmission costs in this proceeding?

A. No. The Protocol does not facilitate the ability of this Commission to determine the appropriate power supply and transmission costs related to serving Washington. With the exception of certain resources (Hydro-Endowment), the Huntington Coal Plant (Coal Endowment), and the situs assignment of demand-side management programs, all Company resources are deemed allocated among all of the states. For Washington, this results in the necessary review of the costs associated with all Company resources and contracts, including those acquired specifically to serve load in the Eastern Control Area. The Protocol also requires the Commission to determine the prudence of all newly acquired resources, irrespective of where—or for whom—the resources are acquired. Section XII of the Protocol states:

> PacifiCorp shall plan and acquire new Resources on a system-wide least cost, least risk basis. All prudently incurred investments in Resources will be reflected in rates on a cost-of service basis.

The Protocol does not distinguish between resources acquired for the "system" versus resources acquired for specific loads or jurisdictions. Simple statements that the resource acquisitions are prudent because the Company says it operates its system in an integrated manner are insufficient.

Q. Can you provide an example of that claim?

A. Yes. Staff asked the Company to provide support for the Craig, Hayden, and Cholla 4 resources addressed in the Joint Report. Staff asked for all studies, analyses, and documents to support the claim that these resources benefit Washington and to indicate where those claims have been specifically quantified in the information provided. The Company's response was:

> As explained in Mr. Widmer's testimony the Company plans and operates its system on an integrated basis to capture the efficiencies of its system, which benefits all of the Company's customers by keeping net power costs as low as possible. Washington customers benefit from these captured efficiencies based on their share of system allocated resources. (*PacifiCorp's Response to Staff Data Request No. 25*).

Staff is forced to evaluate the resource for cost recovery, lacking a clear and demonstrable showing by the Company, backed by analysis, that the resource provides benefits to Washington. This same burden exists for resources that are part of the Company's portfolio in this proceeding, as well as future resource acquisitions to serve non-Washington load that have been recently announced.

Q. Are there other specific Commission actions required under the Protocol?

A. Yes. Under the Protocol, each jurisdiction must evaluate any resources acquired pursuant to Portfolio Standards adopted by other jurisdictions in order to determine whether the Company's costs have been "unreasonably" increased. Under the Protocol, Staff and the Commission also have responsibilities regarding the sale of resources that are freed-up as a result of direct access programs in other states. Under the Protocol, Staff and the Commission are expected to act on a case-by-case basis in dealing with allocations resulting from mergers, condemnations, municipalization, and the sale or acquisition of new service territory. Finally, the Protocol provides for a MSP Standing Committee consisting of one member from each commission. The Standing Committee can then appoint subcommittees of interested parties or retain third parties for additional purposes. Based on past experiences with the MSP, it is unlikely that Washington's voice will carry much weight in determining the directions the Protocol may take.

Q. Are there any other general Protocol issues that you want to address before turning to more specific concerns?

A. Yes. Company witness Ms. Johansen states that:

> If the Protocol is ultimately adopted, all of the states served by the Company will benefit from stable and predictable cost allocation. Moreover, the Protocol would facilitate the Company's ability to implement any particular state's energy policies, such as direct access in Oregon or the pursuit of renewable portfolio standards. If the Protocol is not adopted, however, the Company and its customers will suffer as each state continues to act independently in determining its share of the Company's operating costs. (*Exhibit ___ (JAJ-1T), at 9, lines 1-6*).

Q. Do you agree with Ms. Johansen's conclusions?

A. No. I am not convinced that the Protocol will result in "stable and predictable" cost allocations. Recent history, including the ongoing proceedings in other states, leads me to conclude that states will only continue to adopt allocations methodologies based on their own particular revenue requirement best interests or policies. This has been the case in the past (the unilateral adoption in Utah of rolled-in allocations) and there is no reason to expect that such behavior will not continue. Also, "stable and predictable" cost allocations do not result in stable and predictable rates. The increased cost pressures caused by resources not acquired for Washington will result in less than stable or predictable rates.

Q. Do you believe the Company and its customers will truly suffer if the Protocol is not adopted?

A. If that were the case, it is hard to imagine why the Company would now have no less than three Protocol versions floating around. It's also hard to understand why the Company would have agreed to a "rate cap" in the jurisdiction with the most growth. I believe the Company has to be dutiful in identifying and presenting the appropriate costs to the jurisdictions for recovery. If that is done, failure for one jurisdiction to hold itself responsible for costs to serve its operations, is not a failure of the allocation methodology. It is a failure of responsibility.

Q. Ms. Johansen states: "[I]t is our [the Company's] desire to assure the different states that they are each responsible for an equitable and reasonable portion of

our operating system that is at the heart of our desire to resolve our multi-jurisdiction issues." (Exhibit ___, (JAJ-1T), at 9, lines 13-13). What is your reaction to this statement?

A. Actions speak louder than words. States should not be responsible for costs that are based on unprincipled allocation methodologies or stipulated rate caps in fast growing jurisdictions. These are not "equitable and reasonable" factors. An "equitable and reasonable portion" does not mean a share based on whatever portion is left after other jurisdictions have adopted their chosen portion. The Company has forgotten the testimony provided by its own witness regarding the subsidization of unfavorable actions in another jurisdiction, "If a subsidy is required, it's going to be a subsidy by the shareholder." (Cause No. U-87-1338-1T, Tr. 733). The Company now desires to shift that commitment to the customers, by claiming that not adopting the Protocol will create "the potential for a regulatory race to the bottom." (Exhibit No. ___ (JAJ-1T), at 9, lines 7-8). From a Washington perspective, the Company is putting too much effort into trying to get Washington to pay for costs associated with serving other jurisdictions, and not enough effort in providing a fair measure of the costs to serve Washington operations.

Q. You stated that you carried out your evaluation of the Protocol on two levels. The second level addresses your concerns related to the treatment of specific resources. Please identify the specific issue of concern.

A. There is nothing new here. The area of greatest concern is the Protocol's allocation to Washington, on a rolled-in basis, of resource costs. These include resources from the original Utah Power & Light Company, resources acquired subsequent to the merger and included in the Joint Report, resources acquired since the Joint Report, and the resources that have been more recently announced.

Q. Isn't it proper to allocate resource costs based on a rolled-in methodology in an integrated system?

A. No, not necessarily. The degree of integration is very important, as is the actual load characteristics and growth rates of the different jurisdictions. Only if a utility's system is integrated without significant congestion and the load and growth rate characteristics are similar, may a rolled-in inter-jurisdictional allocation methodology be appropriate. There may also be resource acquisition policy differences between jurisdictions that may make the use of rolled-in methodologies inappropriate.

Q. Are your concerns expressed above regarding Protocol's allocations merely hypothetical?

A. No, the Protocol presents real problems in the real world. The treatment of actual and planned resource acquisitions can be evaluated. I will limit my discussion here to those generating resources acquired since 1986 that are the subject of the Joint Report , the recently acquired Gadsby and West Valley generating projects, and the more recent acquisitions of the Current Creek and Lakeside Projects.

Q. Which generating resources are included in the Joint Report?

A. The acquisition of Cholla Unit No. 4, the Craig and Hayden Generating Units, the James River Cogeneration Project, the Hermiston Cogeneration Project, and the Wyoming Wind Project.

Q. How are these resources to be allocated to the different jurisdictions under the Protocol?

A. All of the resources, with exception of Cholla Unit No. 4, are treated as System Resources, allocated based on the System Generation Factor—a combination of capacity and energy. Cholla and its associated exchange contract are treated as a Seasonal Resource.

Q. Has the Company demonstrated that these resources were acquired prudently to satisfy increased load growth or demand in Washington?

A. No. The Company continues to rely upon nothing more than the notion that:

> [T]he Company operates and plans its system on an integrated basis to capture the efficiencies of its system, which benefits all of the Company's customers by keeping net power costs as low as possible. (*Exhibit No. ___ (MTW-1T), at 20, lines 12-15*).

It is important to note that the Company has contradicted this statement in its IRP Update, which implies that the Company does not operate or plan its system in an integrated manner. (Update to PacifiCorp's IRP, at 12 (Oct. 29, 2003)). Mr. Widmer claims that the resources are eligible for inclusion in Washington rates simply because the Joint Report concluded they were prudently acquired on a system basis (Exhibit No. ___ (MTW-1T), at 20, lines 19-22). However, the Joint Report acknowledges that a state specific showing is necessary. Mr. Widmer points out that the Protocol does not require that the Company demonstrate a "state-specific" benefit for particular resources before they can be recovered in a particular state's retail rates. (Joint Report, at 62). However, the Company then states:

> As to a resource acquisition that was not consistent with state specific rules and prudence standards, any portion found to be imprudent would not be borne by Washington ratepayers. (*PacifiCorp Response to Staff Data Request No. 20*)

Thus, it appears that there is some conflict with Washington's requirements and the treatment of resources in the Protocol.

Q. Did the Company attempt any showing of state specific need?

A. Mr. Widmer does respond to specific issues raised by Staff in the Joint Report, after restating the Company's contention that the Protocol does not require a state-specific showing. He also concludes that these resources have been found to be necessary because all other states, except Idaho, have already included these resources in their rates. (Exhibit ___ (MTW-1T), at 21, lines 16-18).

Q. What issues does the Company address?

A. Mr. Widmer compares Washington's 82 MW share (updated) of the 1058 MW of net resources acquired through 2002 to Washington's sales increase. The corrected sales growth from June 1985 until March 2003 is 161 MWs. Mr. Widmer, therefore, claims that Washington's load growth contributes "heavily" to the need to add the new resources, and, thus these "resources were acquired prudently to satisfy increased load growth in Washington State." (Exhibit ___ (MTW-1T), at 22, lines 6-9).

Q. Did the Company provide any other studies or analyses supporting its determination of state specific prudence for these resources?

A. No. Mr. Widmer testifies to the geographic split of the resources and makes broad statements about resource diversity and, operational flexibility, but no analyses or studies are provided. Mr. Widmer also discusses peak diversity and how Western and Eastern resources can be used to serve each other's load, as long as they are not being utilized. However, no studies indicating transmission availability, resource availability and costs, market alternatives, or any other factors that might affect the use or cost effectiveness of resources to serve respective loads has been provided.

Q. Have you analyzed the load characteristics of the Company's jurisdictions?

A. Yes. I have used the actual load data provided by the Company to analyze recent historical growth in both peak load and energy use for each of the jurisdictions. In addition, I have analyzed the peak and energy load shape of both Washington and Utah. Exhibit No.___(APB-~~2~~4) presents the load information in graphical form.

Q. What does the analysis of historical peak and energy loads indicate?

A. Annual energy use of each jurisdiction for the years 1993 through 2003 are shown on Page 1 of Exhibit No.___(APB-~~3~~4). The Graph shows both the magnitude and historical growth rates of the respective state's annual energy use. Clearly Washington has not experienced the same level or rate of growth as has Utah. The graph on page 2 of Exhibit No.___ (APB-~~3~~4) shows the historical growth in annual peak load. Once again, the information shows that Utah's growth rate far exceeds that of the other jurisdictions. The peak and energy growth that Washington has experienced clearly does not support the acquisition of all of the generating facilities that are the subject of the Joint Report and certainly does not support the more recent acquisitions or announced acquisitions.

Q. What does your analysis of load shape indicate?

A. Eleven year averages of both monthly energy and peak load for Washington and Utah are presented on Page 3 and 4 of Exhibit No.___(APB-~~3~~4). This monthly load shape information indicates that Washington load is definitely winter peaking, but relatively flat when compared to the summer peaking load shape of Utah. Washington does have a small bump in load during the months of July and August. However, this information clearly suggests that any Washington load growth is best met with higher load factor, base-load generation. The need for summer peaking resources is best demonstrated by the Utah load shape.

Q. Did you analyze forecast load growth?

A. I reviewed the latest material presented in the Update to PacifiCorp's 2003 Integrated Resource Plan submitted to the Commission in October of 2003. The Company, at various times, has indicated to Staff that Washington is one of the fastest growing states. This is curious given the historical load growth previously discussed. The Company's remarks are also not supported by the IRP Update, in which the Company has lowered the long-term forecasted growth rate for sales to Washington from 2.0 percent to 1.8 percent, while raising the growth rate for sales to Utah from 3.0 percent to 3.5 percent. The effect on resource acquisitions of that change is even more pronounced due to the magnitude difference in the state's loads. The IRP Update states:

> There has been a shift in the forecast such that more growth is expected on the East side of the service area (Utah, Wyoming, Idaho) and less growth is expected on the West side of the service area (Oregon, California, and Washington). (*Update to PacifiCorp's 2003 IRP, at 4 (Oct. 29, 2004)*).

The Company has forecast higher non-coincident peak demand for Washington – 3.0 percent versus the previous 1.8 percent. However, even this increase in forecast peak demand growth rate pales in comparison to Utah's forecast 5.1

percent growth rate. In addition, the increase in Washington's forecast peak demand growth rate is projected to be from a higher conversion rate from evaporative coolers to air conditioners and assumed larger households. While important factors, they are not the kind of robust economic projections that support the immediate acquisition of a large number of resources. If the growth truly appears, the Company should be able to clearly demonstrate the need for additional resources and support a Westside RFP that will enable the parties to determine the prudence of resources being assigned or allocated to Washington.

Q. Does the Protocol fairly allocate the costs associated with the Cholla No. 4, Craig, and Hayden resources to Washington customers?

A. No. These resources are clearly within the Eastern Control Area. The Company has been unable to demonstrate that these specific resources were acquired to meet the needs of Washington operations or provide actual benefits to Washington customers. Staff has asked for all studies, analyses, and documents supporting the claims by the Company that those resources benefit Washington customers. Once again, the Company provided only the following statement:

> [T]he Company plans and operates its system on an integrated basis to capture the efficiencies of its system, which benefits all of the Company's customers by keeping net power costs as low as possible. Washington customers benefit form these captured

> efficiencies based on their share of system allocated resources.
> (*PacifiCorp Response to Staff Data Request No. 25*)

Even the Joint Report recognized that it is difficult to determine whether or not the Cholla project was cost-effective compared to alternatives because there was no open bidding when the Company acquired Cholla. In regards to the Craig and Hayden resources, Staff recognized that the plants, although not needed at the time of the acquisitions, could provide value to the system primarily through wholesale sales. The specific need to acquire those resources for Washington was never established.

Q. Have you attempted to further evaluate whether these resources provide value to Washington sufficient to allocate a share of the costs to Washington?

A. Yes. The Company has claimed that Washington benefits from several features of the Cholla transaction, namely two seasonal exchanges. I asked the Company to provide all studies, analyses, and documents quantifying the benefit to Washington. In its answer, the Company only referenced the same data request response quoted above. (PacifiCorp Response to Staff Data Request No. 30). I then turned to copies of material presented to the Company's Board of Directors regarding the acquisition of Craig, Hayden, and Cholla No. 4 properties, which Staff received in response to its Data Request No. 26. Although those materials consist of "confidential" presentations and information, there was no discussion of benefits to Washington. In fact, the material appeared to focus on subjects not related to retail load but rather, the potential of various wholesale markets.

Q. Does the Protocol result in costs associated with the James River and Hermiston cogeneration projects being allocated to Washington?

A. Yes. These resources are treated as "System Resources" to be allocated to Washington.

Q. Has the Company provided any showing that these resources provide specific benefits to Washington customers?

A. No. However, the Company also has not demonstrated that these resources provide benefits to the Eastern Control Area either. The Company's testimony simply states that the Joint Report concludes that these resources where acquired prudently on a system-wide basis. Mr. Widmer then concludes that those resources therefore produce benefits to Washington because they provide operational flexibility and diversity benefits. Neither of those characteristics were quantified.

Q. Does the Joint Report conclude that these resources have value for Washington customers?

A. The Joint Report concludes that, in addition to meeting system needs, the James River Cogeneration Project is ideally situated to serve Washington. The Joint Report identifies several benefits for Washington customers arising from the acquisition of the Hermiston facility.

Q. Are the costs associated with these resources properly allocated to the jurisdictions under the Protocol?

A. Staff recommends that the Commission accept these two resources for cost recovery in Washington rates. However the Company has not shown that these resources provide specific benefits to the East and should be allocated to Eastern Control Area jurisdictions.

Q. Does the Protocol result in costs associated with the Foote Creek Wind Project being allocated to Washington?

A. Yes. This resource is treated as a "System Resources" with costs allocated to Washington.

Q. Has the Company demonstrated that the Foote Creek Wind provides specific benefits to Washington?

A. No. The Company presents the same system-wide justification as it did for the other resources in the Joint Report. Thus, the Protocol improperly allocates costs of the project to Washington.

Q. Turning to other recently acquired resources, will costs associated with the Gadsby and West Valley generating projects be allocated to Washington under the Protocol?

A. Yes. These resources are assigned as "System Resources" with costs allocated to Washington. Both these projects were acquired to meet the summer peaking needs of the Eastern Control area, but the Protocol does not treat them as "Seasonal Resources." That distinction results in the costs being allocated to all jurisdictions based on annual load characteristics.

Q. Please describe the two resources.

A. The Gadsby Project consists of three highly efficient gas turbine generators located in Salt Lake City, Utah. Total installed capacity of the project is 120 MWs with a cost of approximately $74 million. The West Valley Project actually consists of a 15-year operating lease from a subsidiary of PacifiCorp Power

Marketing, for the output from a 200 MW gas-fired, simple-cycle combustion turbine generating station in West Valley, near Salt Lake City. Total annual lease payments are approximately $15 million.

Q. Has Staff addressed these two projects before?

A. Yes, in Docket No. UE-020417, Staff presented extensive argument to the Commission regarding these projects. The relevant excerpt for Staff's Post-Hearing Brief can be found in Exhibit No.___ (APB-43). Staff continues to assert that these resources were acquired to meet the needs of the Company's Eastern Control Area, particularly the summer load in Utah.

Q. Has the Company addressed the prudence of acquiring these two resources?

A. Company witness Mr. Tallman reviews the process through which the resources were acquired. (Exhibit No.___ (MRT-1T)). He discusses the need for additional resources, along with the RFP process carried out by the Company. He addresses alternatives to the acquired resources, provides a description of the West Valley lease, and provides cost information supporting the lease arrangement. He also provides a description of the Gadsby Project, including cost and operational features, and he discusses alternatives to that project.

Q. Has Mr. Tallman's testimony changed Staff's opinion that Washington should not be allocated costs associated with these projects?

A. No. In fact, Mr. Tallman's testimony reinforces Staff's position that the West Valley and Gadsby resources should not be allocated to Washington. Mr. Tallman addresses the RFP associated with these projects. The RFP, which was not filed in Washington for Commission review, clearly states that the Company acquired the for delivery into the Eastern Control Area. Mr. Tallman also states that: "The Company's goal was to secure cost effective resources to meet its East-side capacity requirements." (Exhibit ___, (MRT-1T), at 3, lines 18-19). With respect to the West Valley Project, Mr. Tallman further testifies that:

> [T]he West Valley Project provides system benefits by expanding resource diversity, increasing voltage support and reliability, and reducing the risk of incurring unexpectedly high costs associated with wholesale market purchases. This level of flexibility is important to the Company because it enhances the ability of the East control area to recover from the unexpected loss of transmission import capability or the unexpected loss of other generation units. Lastly, because the West Valley Project is located in the Company's major load center east of the Cascade Mountains, it avoids transmission costs and constraints historically incurred in meeting summer peak load in the East control area. (*Exhibit ___, (MRT-1T), at 8, lines 12-20*).

The same general statements are made regarding the Gadsby Project. In addition, when discussing the design and operating assumptions of that plant, Mr. Tallman states that:

> The Gadsby Project was designed to be operated when the incremental generation cost is below market and during instances when a resource is required with short notice or when PacifiCorp has load service obligations in the East control area and there is no remaining transmission import capability left. (*Exhibit ___, (MRT-1T) at 18, lines 18-22*).

When discussing alternatives to the Gadsby Project, Mr. Tallman said that the Company considered entering into short-term market purchases to meet "the urgent need for energy during summer peak demand." (Exhibit ___, (MRT-1T) at 21, lines 1-2). In explaining why the Company did not enter into such contracts, he states:

> In recent years, the Company has, in fact, served peak summer load in Utah through short-term contracts. The Company, however, found it was paying a substantial premium to import energy into Utah to meet summer loads. (*Exhibit ___, (MRT-1T), at 21, lines 8-10*).

All of these statements point to the fact that this resource was acquired for Utah and should not be allocated to Washington without a showing of benefits for Washington.

Q. Has the Company provided any showing of benefits associated with these projects to the Western Control Area and to Washington?

A. No. The Company's showing is limited to broad statements regarding the reduction of system-wide net power costs, of which Washington customers are allocated a share, supported by claims of reductions in volatile wholesale markets and transmission costs associated with importing power into a transmission constrained area. The transmission costs that are saved relate to wheeling costs from Southern California to Utah, which are plainly associated with the Eastern Control Area. (Exhibit ___, (MRT-1T) at 21, lines 8-13).

Q. What other support for allocating costs associated with these projects was provided by the Company?

A. The Company claims that these resources would be available to serve the West through various wheeling or exchange arrangements.

Q. Has the Company provided any studies or analyses that quantify these claims or shown that the resources and transmission capability would be available if needed by the West on a firm basis sufficient to warrant allocation of costs to Washington?

A. No.

Q. Has the Company claimed other benefits for Washington?

A. The Company says that the acquisitions will add diversity to its portfolio and add voltage support to the Company's transmission system. Finally, the

Company states the projects will provide a hedge during times of unexpectedly high wholesale power costs.

Q. Are you saying that there is no benefit to Washington of either the Gadsby or West Valley projects?

A. No. I am questioning the implied extent of benefits to Washington, benefits that are clearly subject to many conditions, including resource availability and transmission constraints, and benefits that also were never identified in the acquisition phase of the resources. The calculation of benefits is also made impossible by the lack of a Westside RFP that would have provided a benchmark. It would be more appropriate to capture the benefits, if they actually exist for Washington, for projects clearly acquired for one control area, through devises such as transfer pricing. In that way, for example, the East can retain benefits, and the West can obtain benefits to the extent that market prices for Eastern power products are less that Western alternatives and the product is actually deliverable. This is a more appropriate way to "allocate" costs, rather than "rolling-in" all costs for resources acquired in the East.

Q. Is it your opinion that the Protocol does not properly allocated the costs associated with resources, such as Gadsby and West Valley?

A. Yes. I believe that an inter-jurisdictional allocation methodology that assigns all of the costs to the control area directly utilizing the resource is more appropriate as a starting point for setting rates. Actual benefits that can be delivered from one control area to the other can be captured by the use of transfer pricing, to the extent that those benefits may occur. Allocating costs associated with Gadsby and West Valley Projects on an automatic "rolled-in" basis to the Western Control Area makes no principled sense.

Q. Do you address the prudence of the Company's acquisition of these projects?

A. No. Staff's recommendation regarding the inter-jurisdiction costs allocation method for this proceeding does not require Commission action on these resources. In addition, Staff's recommendation eliminates the burden of determining prudence for resources acquired to serve the Eastern Control Area, a burden that includes evaluating need, RFP bid results, transmission constraints, regulatory conditions, and alternatives in markets less familiar to this Commission. Staff's recommended treatment of these resources also eliminates controversy in determining the appropriate resource category (System Resources or Seasonal Resources) to place the projects within the Protocol. Finally, Staff's treatment of these resources eliminates potential controversy from a ratemaking viewpoint of the West Valley lease and subsidiary transactions.

Q. Are there other issues associated with the West Valley Project that are relevant to your recommendation?

A. Yes. On June 14, 2004, the Company notified Staff of its intent to terminate its lease with the West Valley Project owners. This action is allowed under the contract. I am not aware of the details at the present time, including whether the Company will be requesting recovery of buyout costs. If the Commission chooses to adopt the Protocol, I recommend an adjustment to remove this resource. Adopting Staff's recommendation, however, requires no further Commission action because the costs were not assigned to the Western Control Area. However, the removal of the West Valley resource may affect energy balancing transfers and, therefore, costs in some way.

Q. What issues arise regarding the recently announced Current Creek and Lakeside projects?

A. While not a subject of this proceeding, these resources are important from the perspective of how the Protocol will allocate their costs. I am concerned that the Protocol will result in the allocation to Washington customers of costs associated with these large projects that were built to serve Utah. In addition, I remain very concerned about the regulatory burden of evaluating these projects for prudence.

Q. Please describe the two projects.

A. The Current Creek Power Project, located in Mona, Utah, will initially consist of two gas-fired combustion turbines with a capacity of 280 MWs, to be in operation by June 2005. By March 2006, the plant will be converted to combined-cycle turbines with a total capacity of 525 MWs. The Utah Commission has granted a Certificate of Convenience and Necessity for the project and construction has begun. The installed cost of the Current Creek Power Project is approximately $343 million. The Lakeside Project is anticipated to be a 534 MW gas-fired combined-cycle turbine generating plant located near Salt lake City. The cost of the plant is approximately $330 million. Regulatory approval processes are ongoing at the Utah Commission. (Utah Docket No. 04-035-30).

Q. How will the costs of these projects be treated under the Protocol?

A. Current Creek will initially be treated as a "Seasonal Resource" until completed, at which point it will be considered a "System Resource." Although not specifically stated, the Lakeside Project will be considered a "System Resource."

Q. Why should this treatment of costs related to future resources be an issue for this Commission now?

A. As with the Gadsby and West Valley Projects, the Protocol results in Current Creek and Lakeside costs being allocated to Washington. In addition, Staff remains concerned about the burden placed on the Commission to evaluate the prudence of the resource additions in another control area. This real concern can be demonstrated by looking at the certification proceedings in Utah involving Current Creek. Without burdening this record with details, it can said that there was considerable criticism in the Company's handling of the bidding process, a process that resulted in the Company choosing its own bid over other alternatives. If Staff and the Commission are to protect Washington customers from excess "rolled-in" costs, it may be necessary to actively participate in the various proceedings in other jurisdictions addressing resource acquisitions that result in upward rate pressure for Washington customers.

Q. Does the Current Creek Project provide benefits to Washington?

A. The Company's testimony in the Utah certification proceeding for Current Creek makes no mention of specific benefits for the Western Control Area or for Washington. There are, however, many, many references to the needs of Utah, especially along Utah's Wasatch Front. Some of this testimony[6] includes such statements as:

- The most prudent solution to meet future resource imbalances and to insure reliable sources of energy is to bring in new supply resources along the Wasatch Front to decrease dependency on the backbone transmission system and reliance upon the wholesale energy market. (Thurgood, at 12)

- My testimony will address the growing gap between PacifiCorp's load and the resources available to serve it with an emphasis on the implications for Utah. (Cassity, at 1)

- The Eastern Control area, in general, requires more physical resources to fulfill PacifiCorp's obligation to serve load. Discussed at a number of 22 public meetings supporting the development of the IRP, transmission constraints distinguish Utah from other areas of the system. This constraints limit imports from other electrical systems and create a need to buy or build additional imports into Utah, and in particular, the Wasatch Front. (Cassity, at 4)

- The revised load forecast, in conjunction with updated inputs and assumptions, result in a substantially larger load and resource gap for the East (in Utah in particular) than that projected in the 2003 IRP. This larger resource gap necessitates a greater amount of flexible resources sooner than identified in the IRP. The Current Creek Project, in conjunction with other actions by the Company, is anticipated to meet that need. (Cassity, at 8)

These are only small portions of the Utah testimony that address the needs of the Eastern Control Area and Utah in particular. There is additional testimony describing the RFP and bid process, including the recognition that these

[6] Utah Docket No. 04-035-30.

resources were being acquired for the Eastern Control Area. Again, there was no testimony addressing any needs of the West that could be met by the Eastern resources.

Q. Did the Company file an RFP in Washington contemporaneously with the acquisition of these new projects?

A. No. The Company did, however, file a request for waiver, so that it would not have to file an RFP in Washington for generating resources. Confidential documents indicate that there is no need for West Side capacity additions. In fact, the memorandum presented at the PacifiCorp Board Meeting discussing RFP options related to Current Creek was titled "PacifiCorp Integrated Resource Plan, East System Supply-Side Implementation."

Q. Is the Lakeside Generation Project expected to provide benefits to Washington?

A. The acquisition of this resource in the early stages. However the Company's press release says that the Lakeside Project offers "the best cost and risk balance for our customers." Staff requested analyses, studies, and documents that support this statement. We also asked for Board material presented to the Board, copies of RFPs leading to the acquisition, and all analysis, studies, and documents demonstrating the benefits to Washington customers from the project. The Company did not provide <u>any</u> documents supporting its claims made in the Press Release. In spite of Staff's requests, the Company says necessary justification will take place during future certification proceedings in Utah, and, more specifically for Washington, a future general rate case prudence review. (PacifiCorp Response to Staff Data Request No. 212). I can only conclude that the Company has no support for the claims it made in its Press Release.

Q. How would you expect the costs associated with this project be treated under the Protocol?

A. If the earlier projects provide any guidance, the resource would be assigned as a "System Resource" for cost allocation to all jurisdictions.

Q. Do you have any final concerns regarding how new resources are allocated under the Protocol?

A. Yes. I have discussed only the few new, incremental resources that have been recently acquired or announced by the Company. Many of the same arguments for not directly allocating costs across control area can be made for other Eastside resources previously acquired by the Company. This would also be true for resources acquired in the Western Control Area. I continue to be alarmed by the Company's attempts to "roll-in" the costs of resources clearly acquired to serve specific load needs of another jurisdiction, at the same time rate concessions are being adopted for those jurisdictions.

D. Discussion of Revised Protocols

Q. The MSP has continued in the Company's other jurisdictions. Please describe the results of those proceedings.

A. On May 10, 2004, the Commission, as an MSP participant, received from the Company a draft of a Revised Protocol and related appendices. This document was evidently the result of continued discussions between interested parties in Oregon and Utah, including the commissions. The document indicated that the draft would form the basis for the Company's upcoming filings (presumably supplemental testimony) in Utah, Idaho, Oregon, and Wyoming. When asked by Staff whether the Company intended to file supplemental testimony, or other actions, in Washington, no definitive response was obtained. Continued requests by Staff elicited the same lack of certainty. On May 24, 2004, 33 days (now 40 days) before the filing date of Staff's response testimony in this proceeding, I discovered that the Company had made a Revised Protocol filing in Oregon during the previous week. I discovered this fact by monitoring the Internet web sites of other state commissions. The Company did not notify Staff that actual filing had been made in any other state. No filing was made in Washington. Upon request, Staff obtained a copy of the Supplemental Direct Testimony and Exhibits filed in Oregon. In addition, it is Staff's understanding that in Utah, the Company and interested parties continue to make even more revisions to the Revised Protocol that was filed in Oregon. As stated earlier, PacifiCorp and interested parties in Utah apparently have stipulated to a revised Protocol for Utah.[7]

Q. What does the Oregon supplemental testimony state?

A. According to testimony, the Revised Protocol responds to major issues raised in several meetings with Oregon Commission Staff and the Utah Division of Public Utilities, as well as other subsequent individual or multi-party meetings. A Staff member participated in the last of these meeting before the filing in Oregon.

Q. Have you been able to review the Revised Protocol that was filed in Oregon?

A. Only briefly. Since December 3, 2003, I have been evaluating the Protocol that has supported the Company's filing in Washington. Thus, I have assumed that

[7] The Utah Commission issued a scheduling order on June 1, 2004, which set a June 18, 2004, deadline for the parties to file the stipulation containing the revised Protocol. Staff has been unable to confirm if the stipulation was filed.

the Protocol still is the allocation method advocated by the Company. The filing of the Revised Oregon Protocol, and the draft revised Utah Protocol with even different features, came as somewhat of a surprise. The Company has not filed any new versions of a Protocol in Washington, which is disturbing. PacifiCorp's President and Chief Executive Officer, Ms. Johansen, testified that:

> Absent adoption of the Protocol, we are faced with a situation that not only makes it unlikely that we will be able to fully recover costs, but one that actual creates inappropriate incentives for each state to shift costs and avoid carrying its weight. (*Exhibit ___, (JAJ-1T*) at 9, lines 8-11).

PacifiCorp's Executive Vice President responsible for Strategy and Major Projects, Mr. MacRitchie, testified that:

> Adoption of the Protocol for purposes of setting rates in this proceeding will indicate that the Commission believes that the terms of the Protocol are balanced and reasonable and should be followed in future PacifiCorp rate proceedings in Washington. *Exhibit ___, (ANM-1T), at 2, lines 16-18).*

Now, at the eleventh hour, the Company's primary Protocol witnesses, Ms. Kelly and Mr. Duvall, have filed testimony and exhibits in Oregon that undermine the Company's direct case in Washington. PacifiCorp will further undermine its case if it files a revised Protocol in Utah, which appears imminent. The Company should not be allowed to simply wait and file a new Protocol in

Washington during the rebuttal phase of this proceeding, the timing of which would preclude meaningful analysis by the other parties.

Q. Are the Revised Oregon Protocol and the draft Revised Utah Protocol significantly different than the Protocol filed in Washington?

A. Yes, although I have had time to only very briefly review the different versions. The revised Protocols actually reject many of the features contained in the Protocol still filed in this docket. For example, the Protocol contains both a "Hydro-Endowment" and "Coal Endowment" feature. It is my understanding that the Oregon and Utah versions contain neither. The treatment of special contracts and portfolio resources also has changed, as have other features addressing the classification of resources, Qualifying Facilities, direct access, and sustainability.

Q. How does the filing of the different versions of Protocol affect your evaluation of the Company's direct case?

Q. Because the Company has not filed a revised Protocol in this docket, I have evaluated the Protocol that the Company filed with its direct case. However, the Company's direct case in this proceeding can no longer be supported by the Company's original Protocol. This is particularly true for power supply and transmission related costs, given the fact that the allocation of those costs has a significant affect on Washington jurisdictional revenue requirements. The Oregon Protocol and the draft Revised Utah Protocol contain features in direct conflict with the Protocol filed to support the Company's direct case. The fact that these new Protocols were developed in response to the Company's two largest jurisdictions, also leads me to conclude that the Protocol filed in Washington is not sustainable, or even valid, in light of the filings in those jurisdictions. In addition, I am increasingly alarmed by the moving target created by the new filings. With this in mind, my recommendations regarding both inter-jurisdictional cost allocations and the method in which costs to serve Washington operations are determined, are very much affected by the Company's support of the revised Protocols in the other jurisdictions. Not only has the Company's and other ~~party's~~ parties actions in developing the latest proposals confirmed my belief that the Protocol is not sustainable, it supports the use of Staff's alterative approach to cost allocations that is principled and in the public interest for Washington customers.

Q. What specific actions have caused your concern?

A. Throughout the MSP, the positions taken by Utah representatives often have been in conflict with the positions taken by Washington representatives. It is no secret that Washington Staff has continued to support a control area-based inter-jurisdictional cost allocation methodology based on the Hybrid Approach. Although not fully developed in the MSP, and all but ignored in the Protocol, this method effectively would separate the Western Control Area from the Eastern Control Area for purposes of determining rates. This methodology would have continued to put Washington, Oregon, and California in the same "basket", using dynamic allocations for costs within the Western Control Area. However, the recent willingness of Oregon staff to support allocation methodologies in regards to hydro-electric resources and Mid-Columbia contracts that are counter to any previous position consistent with historical treatment, has removed any desire or benefit to remaining tied to Oregon with respect to inter-jurisdictional cost allocation. Under the Revised Oregon Protocol and the draft Revised Utah Protocol, Washington is assigned less total energy from the Mid-Columbia contracts than Utah, and Oregon is assigned virtually all benefits from two of the Mid-Columbia contracts. In addition, the amount of Commission resources that would be necessary to insure that Washington customers are not harmed by Oregon's Direct Access initiative remains a concern for Staff. The administrative burdens of analyzing the effects of direct access programs, including the costs and benefits of freed-up resources and subsequent resource sale approvals, is significant. All of these factors have resulted in Staff's exploring alternative approaches to cost allocation.

Q. Should the Company be allowed to file a Revised Protocol as part of its rebuttal case?

A. No. The Company is very aware that Staff has been reviewing its direct filing, including the Protocol as filed. The Company already has had sufficient time to make a revised filing in Washington recognizing that the two major jurisdictions, and the Company itself, have rejected the Protocol as filed in Washington. I am concerned that the Company intends to file some form of revised Protocol and revised Washington Results of Operations as part of its rebuttal case, which would leave insufficient time for the other parties to review the most fundamental aspect of the Company's case. In essence, the filing of any revised Protocol in rebuttal would raise new issues and would be highly prejudicial to the Commission and responding parties.

V. STAFF'S INTER-JURISDICTIONAL COST ALLOCATION RECOMMENDATION

Q. What is your recommendation regarding the Protocol, and how you would treat the revised versions if they were filed in Washington?

A. My recommendation has been influenced by the recent turn of events. It is now in the best interest of Washington customers for the Commission to take a different approach to determining the appropriate costs necessary to serve Washington operations. The MSP has failed. All of the proposals now on various tables are not based on principles, but are guided by the results oriented horse-trading approach being carried out in the Company's major jurisdictions. Staff recommends that the Commission reject the Company's Protocol in this proceeding. In addition, Staff recommends the Commission not consider revised inter-jurisdictional allocation proposals such as those filed in Oregon and Utah.

Q. What is Staff's recommended inter-jurisdictional cost allocation proposal for use in future Washington proceedings?

A. For the long-term, Staff recommends that the Commission order the Company to move toward a Washington stand-alone or "islanding" approach to evaluate the costs of Washington operations. This would include a more direct method for determining power supply and transmission related costs– costs that are not detrimentally affected by the different requirements of other jurisdictions. It is in the best interest of Washington customers to be as isolated as possible, for ratemaking purposes, from the regulatory and legislative actions of the Company's largest jurisdictions.

However, I recognize that for this proceeding, the Commission requires some measure of the costs to serve Washington. As a transitional tool, therefore, I recommend a control area-based cost allocation method. The Company has provided Staff with a recast of its Results of Operations utilizing two versions of the "Hybrid" model previously discussed. These recasts form the basis on which Staff's remaining adjustments are applied.

Staff recommends that the Commission determine Washington revenue requirement using this methodology only for purposes of this proceeding. I will discuss use of this model in more detail later in my testimony.

Q. Would the use of an alternative costing method preclude the Company from operating its system in the same integrated manner as it does today?

A. No. The system can be electrically operated in the manner it is today, with the limited interconnections between control areas.

Q. Does your long-term "islanding" proposal mean that Washington will be completely cut-off from resource planning activities or resource acquisition strategies of the Company?

A. No. Washington can continue to involved in planning activities and resource acquisition strategies. The Company would be able to adjust rates to recover the cost of new resources acquired, if it can demonstrate that the resource is 1) needed to meet load in Washington, 2) least cost compared to meaningful alternatives in the Western Control Area, and 3) if located in the Eastern Control Area, energy from the resource must be deliverable to Washington. This approach does not preclude the inclusion of the cost of Eastern Control Area resources if they meet those requirements. The principal objective of Staff's alternative method is to insulate Washington from unfair cost shifts created by unprincipled allocation of costs that are incurred to serve other jurisdictions.

Q. Have you fully developed a standalone or islanding approach to determining costs to serve Washington?

A. No. The schedule and sheer magnitude of issues in this proceeding have not allowed Staff to fully develop such an alternative costing approach. In addition, a more robust proposal can be developed when working cooperatively with the Company and other parties outside an adjudicated proceeding. This can be carried out with the Commission's support of such a proposal. Of course, the possibility remains that an adjudicated proceeding may be necessary, but we hold great promise that this will not be necessary once the issues focus on Washington's needs.

Q. Can you provide some examples of how possible alternative approaches to costing might be developed?

A. Yes. For some costs, such as distribution related costs, determination of Washington costs is straightforward. Other costs, such as those related to power supply, transmission service, and administration and general ("A&G") costs are more problematic. For power supply and transmission costs, a reasonable approach would begin by identifying, to the extent possible, actual resources that are used to serve Washington's load. For transmission costs this may include carrying out flow studies to determine the appropriate plant and expenses in which to base Washington's rates. For power supply costs, it should be possible to identify those resources and contracts that have been acquired to serve Washington load on both an historical basis and recent incremental need. Decisions will have to be made regarding the appropriate availability factor for resources such as hydro facilities, in which production capability varies from one year to the next. Decisions will also have to be made in regards to the extent Washington desires to partake and benefit in any wholesale transaction activity. If costs to serve wholesale transactions are not recovered from Washington, then neither should the benefits be assigned. Administrative and general costs may assigned to Washington based on some allocation scheme or, perhaps, on a per unit basis taking into consideration typical costs.

These are not new concepts and, in fact, may be similar to previous proposals by the Company. The Company's corporate restructuring proposal incorporated the concept of a power supply contract to serve the states. Some consideration of how a contract rate might be developed was no doubt explored.

Q. Have you developed any specific proposals?

A. No. I have only begun to formulate potential proposals, focusing on approaches that would address the Commission's MSP principles. Possible approaches may include developing costs based on indices that may be available. For example, the power supply component embedded in rates could be based on some percentage of an annualized weighted market price over time. Another approach for the power supply component, would be to determine Washington's costs based on using the same basic modeling procedures presently carried out by the Company, with the exception that a determined "slice" of Western Control Area resources would be dispatched to meet only Washington's load. Interconnections would be replaced by market buy/sell opportunities. Another approach would be to determine costs based on a defined resource portfolio, perhaps using the average cost per MWh of resources identified to serve Washington's load. For example, the power supply component embedded in rates for Washington could be a weighted average cost of the Westside hydroelectric resources, the Mid-Columbia contracts, Hermiston, and other resources defined to serve Washington. Unit costs and/or benefits from selling or buying ancillary services may have to be included. These approaches represent just a sampling of "out-of-the-box" costing alternatives.

Q. What process and timeframe are necessary to fully develop an alternative proposal to present to the Commission?

A. A process that involves all interested parties would best serve the Company's needs. The Company should take the lead in identifying and outlining several different alternative approaches, such as those discussed above. The parties can then meet to fully develop the appropriate approach over the next 12 to 24 months, working in a co-operative and principled manner.

VI. TRANSITIONAL COST ALLOCATION PROPOSAL

Q. What cost allocation methodology should the Commission use for purposes of this proceeding?

A. The Commission clearly indicated its desire to examine the Company's costs in the context of a general rate case:

> Without such an examination, we can only approximate, even guess at, the important baselines against which claims of excessive power costs and their impact on the Company's operations must be measured if we are to reach meaningful results. We place no particular fault on PacifiCorp for this state of affairs, yet it is the state of affairs we, and the Company face.[8]

In this proceeding, the Company's actions have made the measurement of costs to serve Washington difficult. The use of a rolled-in inter-jurisdictional cost allocation methodology and the subsequent filing of additional proposals in other jurisdictions, are factors that force Staff to recommend a "transitional" allocation proposal. This is necessary so that some reasonable measurement of costs can be made in this proceeding. Thus, Staff recommends for purposes of this proceeding only, that the Commission accept the use of an inter-jurisdictional cost allocation methodology that is control area-based.

Q. Can the costs to serve Washington operations be determined without the use of an inter-jurisdictional cost allocation scheme?

A. Without the thoughtful development of alternative approaches to cost determination such as those suggested by Staff, it is necessary to use some inter-

[8] *In re the Petition of PacifiCorp d/b/a Pacific Power & Light Co. For an Accounting Order Authorizing Deferral of Excess Net Power Costs, et al*, Docket Nos. UE-020417 & UE-991832, Sixth Supplemental Order Denying Petition for Accounting Order; Rejecting Tariff Filing; Authorizing Subsequent Filing, ¶ 32 (July 15, 2003).

jurisdictional cost allocation method. The Company may argue that Staff should be able to determine its system-wide revenue requirement, with a subsequent resolution of allocation issues. However, this is not the approach Staff used in this proceeding. The determination of power supply and transmission-related costs depend highly on the allocation method used. To facilitate a timely review of costs consistent with the use of the control area-based cost allocation method, I only analyzed the revenues and costs assigned to the Western Control Area. For example, I did not evaluate the fixed and operating expenses, or mine costs, associated with Eastern Control Area coal plants. Total system net power costs were not developed. This approach enabled Staff to derive a transitional revenue requirement for Washington, for purposes of this proceeding.

Q. Why is a control area-based inter-jurisdictional cost allocation method appropriate for this proceeding?

A. The control area–based allocation method more closely matches the way the system is actually operated. This method also more closely matches the way that resource additions are planned and acquired by the Company. The Company's own update to its 2003 Integrated Resource Plan submitted to the Commission on October 30, 2003 states:

> PacifiCorp's net position drives resource decisions. The size and timing of new resource decisions hinge upon PacifiCorp's obligations delineated by the net position.
>
> . . . .
>
> Analysis of the new position revealed a need to segment the short position by location. The reason for the change is that the new load forecast and evaluation of the transmission system highlighted an issue related to delivering resources in a transmission-constrained area. Therefore, it was important to have the ability to review these areas of the system and analyze them in more granularity.
>
> This approach differs from the filed IRP. The 2003 IRP first took an energy view of each control area, and then analyzed the capacity position for the total system with a 15% planning margin target. The new approach breaks the system into more detail and looks at the position as two Tier's, based on constraints. <u>The tiered approach is consistent with the manner in which PacifiCorp's Front Office plans for the system in the near term (2-3 years out).</u>

(Emphasis added). The two Tiers are defined as: Tier 1 is the Utah Bubble (loads, resources, and contracts in Southeast Idaho, Utah, and Southwest Wyoming); and Tier 2 is the West Control Area and Four Corners. The Tier 1 area has insufficient resource capacity and is within a transmission constrained area. The update states, at page 14:

> Planning efforts for Tier 1 risks are best managed through a targeted approach. Only geographically specific, physical solutions resolve Tier 1 short positions. Potential solutions include additions of DSM, generation delivered within the constrained area and/or transmission. <u>PacifiCorp is currently engaged in RFP efforts, which will directly impact the Tier 1 position. The outcome of these efforts will drive future planning efforts.</u>"

(Emphasis added). With regard to the Western Control Area, the Company says at page 15 of the update:

> The FY 2005 positions leads to three conclusions. First, the West is essentially resource sufficient for the early years of the planning period. This is particularly true in light of the West's access to market. Sufficient import capability exists to serve the small duration of deficit position as well as deal with contingencies should they arise. Second, the West has sufficient capacity to support both its indigenous peak requirements as well as the peak requirements of the East at the limits allowed by transmission. Finally, the West had sufficient resources to maximize transfers to the East at or near the limits of PacifiCorp's firm rights.

Q. What does all this mean?

A. From a Washington perspective, it means that there are distinctions between the Western and Eastern Control areas that demonstrate that a control area-based allocation methodology is not an unreasonable starting point for determining costs to serve Washington. In light of the Company's own IRP Update, it is interesting that the Company continues to support an inter-jurisdictional cost allocation methodology based on rolling-in the costs of resources. The control area-based cost allocation methodology is a giant step toward a better evaluation of actual costs to serve Washington. The assignment of resources by control area also better reflects the manner in which the system is operated. This is the best method available, in the timeframe allowed, to evaluate Washington costs until the alternative approach can be developed.

Q. Should the Commission now consider adopting a control area-based cost allocation methodology for future use?

A. Not at this time. Alternative approaches to cost determination are worth investigating and may more sustainable in the long run. Although the control area-based approach is a more principled approach than any of the Protocol versions, it still has many features that would require additional evaluation and fine-tuning. These features include inter-change transfer pricing, treatment of exchanges, and transmission cost allocation. In addition, the dynamic allocation within the Western Control Area would need refinement, or even elimination, in order to address direct access program and policy directives from Oregon or California. The use of this method as a one-time transitional approach allows a simple, snap-shot look at load factors used in the model without the controversy of how addressing future events. The future efforts of the Company and other parties, would be best spent on a sustainable Washington stand-alone or islanding approach.

For purposes of determining the cost to serve Washington in this proceeding and recognizing that this is a transitional methodology, limited adjustments have been made to the Hybrid model that was provided by the Company in response to data requests.

Q. Please summarize the major features of the control area-based model used in Staff's transitional inter-jurisdictional cost allocation proposal.

A. The basic model divides the generation system for regulatory accounting purposes into two parts – the East and West regions. Each state's load, company-owned resources, and power contracts are assigned to one of the two regions. Western Region loads include Washington, Oregon, and California. The intent is to set rates that recover the fixed and variable costs of the generating resources assigned to that Region. The assignment of loads and resources is consistent with the location of loads and resources within the Company's two control areas. The model also includes an interchange methodology that allocates costs and revenues associated with the other two elements of production costs—system balancing purchases, and sales and interchanges of energy made between the two regions. The model also specifies a method by which the regions share operational reserves. Within each region, the model anticipates using a dynamic, rolled-in methodology for allocating costs. However, as discussed earlier, the one-time use of this methodology allows the allocators to be based on a simple, snap-shot analysis of load. The model assigns most of the Company's existing hydroelectric resources and the majority of long-term power purchases to the West Region, while the East Region is assigned the majority of existing thermal resources. The model also assigns transmission plant and firm transmission wheeling expenses to the regions. This is a change from the Company's Protocol and earlier models that used system-wide allocation of those costs. The Company's proposed System Net Power Costs do not change from one allocation methodology to another. The allocation models are run subsequent to the calculation of System Net Power Cost.

Q. Did Staff evaluate all system resources, contracts, and other costs or revenues of the Company?

A. No. Based on the rejection of the Protocol and its rolled-in features, Staff focused its evaluation of power supply and transmission-related costs on those resources that have been assigned to the Western Control Area. Total system costs were not evaluated. While adjustments to those resources assigned to the Eastern Control Area may be appropriate on a system basis, the effect on costs for Washington would be small.

VII. NET POWER COST EXPENSE

Q. Please describe Net Power Cost?

A. Net Power Costs are the normalized operating expenses associated with the Company's generating resources, power purchase and sales transactions, and net transmission expenses. The Company proposes a total normalized net power for the 12-month period ending March 31, 2003 of approximately $553 million. Of that amount approximately $47 million was allocated to Washington using the Protocol. For the reasons discusses earlier, Staff's adjustments to Net Power costs are based on the "Washington Allocated" expense from the allocation model rather than "System" expense from the GRID model.

Q. **How is the Company's Net Power Cost determined?**

A. The System Net Power Cost is developed using the Company's hourly dispatch model or "GRID" model. Company witness Mr. Widmer provides a thorough description of the model, the input parameters, and what output information is available. Another model then applies the inter-jurisdictional allocation factor to determine the Washington allocated Net Power Cost. The Company provided the model, a dedicated computer, and model documentation to Staff for use in this proceeding. Staff compliments the Company on the timely manner in which these materials were provided and the willingness of the Company to address Staff questions regarding the model.

Q. What are Staff's adjustments to the Washington allocated Net Power Cost?

A. Staff's adjustments result in a Washington allocated Net Power Cost of $60,645,872. This compares to the Company's proposed Washington allocated share of $46,979,654. The increase in the Washington allocated Net Power Cost is due to the use of the control area-based allocation methodology that Staff recommends for transitional use in this proceeding. The increase in the Washington allocated Net Power cost must be evaluated in the context of a decrease in rate base as a lesser percentage of fixed costs are assigned to the Western Control Area. Production and Transmission Net Plant assigned to Washington decreases by $39.36 million alone, compared to the Protocol's system allocation.

Q. Please summarize Staff's adjustments to the Washington allocated Net Power Cost.

A. The primary adjustment is the use of the control area-based allocation methodology. The Washington results of operations from this model replaces the Protocol as the foundation for determining Washington allocated Net Power

Cost. This adjustment also includes the initial assignment of transmission related costs based on control area, rather than a system-wide allocation such as in the Protocol. The remaining adjustments relate to changes in model input assumptions, model logic, or adjustments in the allocation of expenses.

Exhibit No.___ (APB-5) shows the effect on the Washington allocated Net Power Cost for each recommended power supply and transmission expense adjustments. In brief, Staff recommends the following adjustments:

- Use control area-based allocations for both power supply and transmission-related costs.
- Narrow the use of water years to plus/minus one standard deviation from the mean of available data.
- Remove annual costs associated with Aquila Hydro Hedge (a proposed Schedule passing through the benefits/payments is addressed in the Joint Testimony regarding rate spread and rate design).
- Remove annual costs associated with the Morgan Stanley Temperature Hedge.
- Correct for model error in purchase of Emergency Power.
- Correct for the effect of Market Caps in the GRID Model.

- Adjust transmission wheeling expenses allocated to the Western Control Area.
- Incorporate a number of corrections to the GRID power study that have been recognized by the Company.

A. Control Area-Based Cost Allocation Adjustment

Q. Please describe this adjustment.

A. This adjustment reflects the use of the control area-based cost allocation methodology with power supply and transmission costs assigned to control areas.

Q. What is the effect on the Washington allocated Net Power Cost of using the control area-based allocation methodology?

A. Exhibit No.___ (APB-5) shows Washington's allocated share of Net Power Cost as approximately $67.3 million before any further adjustments. This is an increase of $20.3 million from the Company's proposed amount of approximately $47 million. Net power supply and transmission related plant decreases by only $7.8 million.

Q. What is the effect on Washington's allocated Net Power Cost from assigning just the transmission costs to control areas as compared to a system-wide allocation per the Protocol?

A Washington's allocated Net Power Costs increases by almost $7.3 million. Net rate base decreases by approximately $7.8 million. The overall effect on Washington revenue requirement is an increase of approximately $3.1 million. This is based on the Company's initial assignment of transmission wheeling contracts. I will examine these in more detail later in this testimony. The Company's recasts from Staff Data Request Nos. 4 and 213 are used to make this comparison.

Q. Why are transmission expenses assigned to the control area rather than allocating them on a system basis when it is not in Washington's best interest to do so?

A. The assignment of these costs to the control areas is only the initial step. I recommend further adjustments later in my testimony. The assignment of these expenses to the control areas as a starting point reflects Staff's principled approach.

B. Water Year Adjustment

Q. Please describe the Water Year adjustment.

A. I recommend that normalized power supply costs determined from the Company's dispatch model use water-years that are one standard deviation from the mean of available data. This methodology replaces the 40-year rolling average methodology that has been previously adopted by the Commission.

Q. Please describe the relationship between water- years and normalized system power supply expense.

A. The calculation of normalized power supply expense begins with a model that simulates hydroelectric generation based on historical stream flows, current plant efficiencies, storage capabilities, flow requirements, and other factors. The output from that model is then used in an hourly dispatch model (the Company's GRID model) to simulate the operation of the Company's power supply system for each water-year. The GRID results from each water-year are averaged to determine normalized net power costs.

For years, the issues of how many water-years to use and which ones to use in setting normalized power supply expenses have come before this Commission. Various proposals by the electric companies, Staff, and other parties have been reviewed and either rejected or adopted. The latest

Commission approved methodology utilizes a 40-year series of hydro data to develop normalized power supply costs.

Q. Why does Staff propose a different methodology at this time for this PacifiCorp?

A. Two factors led Staff to conclude that an alternative approach is appropriate. The first is the recent, very real tendency for the regulated electric utilities to request rate relief when higher than expected actual power supply expenses occur due to "unforeseen" events. Bad water -years and their effect on actual power supply costs have been cited as one of the unforeseen events. Debate then occurs over the extent that existing rates actually include consideration of unfavorable water conditions, and whether the company is due relief given the costs that are embedded in rates using the normalization methodology. The region's common use of normalizing power supply expenses for purposes of ratemaking is designed to give the companies the opportunity to recover their costs over time, given a variety of water conditions. Rates using, for example, the 40-year rolling average method, reflect revenue requirements under the entire 40-year range of historical water conditions. It is highly unlikely that a company will not seek rate relief for a period long enough to experience all water conditions considered in the normalized ratemaking process. However, companies have filed for rate relief based on higher than expected actual costs, costs that in the near-term may not be recovered with existing revenues. It is then difficult to reconcile the long-term normalized ratemaking process with the need to recover short-term costs and maintain financial integrity for the companies. Staff's water year recommendation will minimize these controversies and simplify the rate setting process by making it clearer what costs are included in rates.

Q. What is the second factor?

A. Two of the three regulated electric utilities now have some form of power cost adjustment mechanism. A Washington islanding or stand-alone approach may include some form of hydro adjustment to address the variability in generation from hydro resources in the Western Control Area. Such a hydro adjustment would address the more significant variations in water conditions throughout the region. It is therefore unnecessary, and even incorrect, to include the power supply costs associated with all water year conditions in the determination of the base power supply costs when a hydro adjustment mechanism exists. The effects on power supply expense of water years above or below some level can be addressed in the mechanism.

Q. The Company does not have a hydro adjustment mechanism at the present time. Why is Staff still recommending the water year adjustment?

A. The first factor, alone, is sufficient to support the adjustment. This is especially true if the Commission accepts Staff's recommendations in this proceeding. The Company would, in a relatively short period of time, be before the Commission to reset its rates based on an islanding or stand-alone approach to ratemaking. There is no need to burden Washington customers with rates designed to recover long-term extremes in power supply costs due to stream flow variations. In the event an extreme year occurs that adversely affects power costs between now and the next general rate case, the Company can make a filing to recover those costs. The adoption of this water year methodology is also appropriate under any scenario. Whether through a hydro adjustment mechanism or though a separate filing requesting relief from drought conditions, it may be in the best interests of customers to see the cost effects of stream flow variations. Embedding the effects of the more extreme stream flow conditions is tantamount to paying an insurance premium and then hoping the Company will have sufficient funds to pay the claim. Actually seeing the effects of more extreme stream flow conditions may result in better customer information in the form of conservation or demand-side measures needs, in the event the Company files for immediate rate relief.

Q. Please describe how normalized power supply costs are calculated using the recommended water-year methodology.

A. The GRID model input file for monthly hydro is analyzed. That file specifies the output of electricity produced at each of the Company's hydro units per month from 1929 to 1978. The annual generation for each facility is calculated and then added to derive the total output from the Company's hydro units for each of the water years. The mean and standard deviation are calculated using total annual generation. Those water years that represent annual generation within plus or minus one standard deviation of the mean are identified. A new monthly hydro input file is developed consisting of the 26 water years that met the test. The GRID model result, with the "filtered" water-years, is compared to the Company's 40-year result. The net power costs that are assigned to the Western Control Area are identified and allocated to Washington.

Q. What are Washington's allocated Net Power Costs under Staff's recommended water year adjustment?

A. Western Control Area Net Power Cost decrease by approximately $13,516,177, with Washington's allocated Net Power Cost decreasing by $3,026,412.

C. Aquila Hydro Hedge Adjustment

Q. Please describe the Aquila Hydro Hedge adjustment.

A. Staff recommends that the annual expense associated with the Aquilla Hydro Hedge be removed from the calculation of the Washington allocated Net Power Cost. Consistent with this recommendation, Staff, through Ms. Steward's Joint Testimony, recommends that the Commission reject the Company's proposed balancing account to pass through benefits and costs, leaving the Company to absorb any costs or retain any payments, including Washington's allocated share of the $5.2 million payment received in the test year or $460,000 .

Q. Please describe the Aquila Hydro Hedge.

A. The hedge is PacifiCorp's contract with Aquila Risk Management Corporation to mitigate the negative effects of annual fluctuations of hydro-conditions upon net power costs. The Company describes the contract as a financial contract structured as a collar, whereby the Company makes a payment to Aquila if stream flows are above a certain level, and Aquila makes a payment to the Company if stream flows are below a certain level. Stream flows are taken from measurement stations on the North Umpqua, Rogue, Columbia, Klamath, and Lewis rivers. The contract runs through September 2006 with an annual cost of $1.75 million.

Q. Why do you exclude the annual premium for the Aquila Hydro Hedge from the Washington allocated Net Power Cost?

A. The contract is not an appropriate power supply expense item. Under normalized ratemaking, rates developed essentially already include "hedging" costs. The Aquila Hydro Hedge is simply a financial instrument. It is not tied to any measure of actual power supply expenses of the Company during the measurement periods. The annual costs of the hedge are included in the GRID model as a power supply expense. The Company does not address the level of expected net benefits to ratepayers as a result of the hedge, only to say that it provides financial protection when stream flows are low. Although the Company describes the "collar" aspect of the hedge, it ignores that the contract works both ways. Data request responses show that the Company expected a negative $10.66 million benefit (on a net present value) based on the simulation of possible hydro conditions. Interestingly, the material provided does not mention pass-throughs to customers of hedge payments, one way or another. The material emphasizes the impact on Company earnings of the hedge. The principle benefit of the hedge, as indicated in the analysis, was to reduce the Company's earnings volatility. If the Company had actually undertaken the transaction for customer benefit there would be no impact on earnings because benefits and costs would simply be passed through. Finally, this contract expires at the end of September 2006. This is not a contract for power to meet load requirements, and therefore does not require replacement upon expiration. Embedding expenses related to such a transaction effectively results in moving the annual payment amount directly to earnings, with no corresponding benefit to customers.

Q. Are you against the Company entering into hedge transactions for its own financial risk purposes?

A. I take no position one way or another.

Q. What is the result of your recommended adjustment?

A. Net Power Cost for the Western Control Area decreases by $1.75 million with the Washington allocated Net Power Cost decreasing by $391,843.

D. Morgan Stanley Temperature Hedge Adjustment

Q. Describe the adjustment relating to the Morgan Stanley Temperature Hedge.

A. Staff recommends that the annual expense associated with the Morgan Stanley Temperature Hedge be removed from the Washington allocated Net Power Cost.

Q. Please describe the Morgan Stanley Temperature Hedge.

A. This instrument is similar to the Aquila Water Hedge. It is a hedge against temperature and power prices, paying the Company in the event of high temperature and high market prices, or low temperature and low market prices. The Company proposes that any payments received would be treated in the same manner as the Aquila Hydro Hedge payments. No payments have been received to date. The agreement runs from November 1, 2003 through March 31, 2004. The annual premium cost of $1.8 million is included in the Company's calculation of Net Power Costs.

Q. Why do you recommend that the premiums associated with the Morgan Stanley Temperature Hedge not be included in the calculation of the Washington allocated Net Power Cost?

A. The principal reason is that the agreement ended March 31,2004. This is a non-recurring cost that should not be included in the calculation of normalized power supply expenses. Similar to the Aquila Hydro Hedge, this hedge is not tied to any actual level of power supply expenses during the period it was in effect. The Company was asked to provide a calculation and supporting work papers showing the benefits from the temperature hedge and where they were reflected in the GRID model. None of the material provided demonstrated that the temperature hedge provided net value to customers. The Company indicated that it did not prepare a separate Net Power Cost study to identify benefits associated with the hedge. Without a clear demonstration that customers receive a benefit from such transactions, the associated costs should not be included in the calculation of the Washington allocated Net Power Cost.

Q. **Are you against the Company entering into temperature hedge transactions for its own financial risk purposes?**

A. Staff is taking no position one way or the other.

Q. What is the result of your recommended adjustment?

A. Normalized Net Power Cost for the Western Control Area decreases by $1.8 million, with the Washington's allocated Net Power Cost decreasing by $403,038.

E. Emergency Purchase Adjustment

Q. Please describe the adjustment to Emergency Purchases.

A. In response to a data request asking the Company to explain a single day purchase of emergency power amounting to approximately $3 million, the Company acknowledged that its GRID model inadvertently made emergency purchases on a leap year day due to a data series error. The exclusion of Market

Cap data for that day forced the model to make emergency energy purchases to meet the day's load, with energy priced at $10,000 per MWh. The emergency purchase was made in the Mid-Columbia Transmission Area within the Western Control Area. The Company indicated that correcting this error reduces Net Power Cost by $2.9 million on a total Company basis. Under Staff's control area-based allocation methodology the costs have been assigned to the Western Control Area, thus the adjustment should reflect that assignment as well.

Q. What is the result of your recommended adjustment?

A. Normalized Net Power Cost for the Western Control Area decreases by $2.9 million, with the Washington's allocated Net Power Cost decreasing by $656,357.

F. Transmission Contract Expense Adjustment

Q. Please describe the adjustment to transmission contract expenses.

A. This adjustment reflects my initial review of transmission wheeling contract expenses that are assigned to the Western Control Area. The assignment was carried out by the Company at the request of Staff and reflects the control area assignment of transmission related costs. Several of the contracts are inappropriately assigned in total, or in part, to the Western Control Area.

Q. What is the basis for Staff's recommended adjustment?

A. There was a significant increase in transmission expenses assigned to the Western Control Area in moving to a control area-based cost allocation methodology where transmission is assigned to each control area based on location. The Washington allocated share of firm wheeling expenses increased from approximately $6.7 million to just under $14 million. This increase was expected due to the prevalent use of BPA's transmission system, rather than Company-owned transmission facilities. It was expected that the increase in wheeling expenses would be somewhat offset by a decrease in transmission rate base assigned to the Western Control Area. However, the net effect of the Company's initial assignment far surpassed expectations. To be fair, this underscores the difficulty in allocating transmission costs for a utility as geographically and resource diverse such as PacifiCorp. Assigning transmission costs to the control areas based on location was a first pass attempt to better reflect Washington's share of transmission costs than a simple allocation of system-wide expenses based on jurisdictional load. It does appear, however, that the assignment of transmission costs to the two control areas requires closer examination.

Q. How did you proceed with your evaluation of transmission costs in this proceeding?

A. For proposes of this proceeding, I first concentrated on reviewing the firm wheeling expenses of the Company. Exhibit No.____ (APB-7) is a listing of the test year firm wheeling contract expenses identified by the control area to which they were initially allocated by the Company. As I stated earlier, the firm wheeling expenses allocated to Washington using the initial control area assignments more than doubled. In reviewing the assignment of the wheeling expenses between control areas, I did not carry out an exhaustive review and evaluation of every firm wheeling expense that the Company has assigned. The purpose of my review was to identify the firm wheeling contracts whose assignment appears questionable at a first glance.

Q. Are you proposing changes to the initial assignment of the firm wheeling contracts?

A. Yes. I propose changes related to the assignment of three contracts. I am first changing the assignment of costs related to the "SCE ISO Charge" from the West to the East. As indicated by the Company in response to a Staff data request, the firm wheeling expense supports a Long-Term Power Sales Agreement between Pacific Power & Light Co. and Southern California Edison ("SCE") dated June

2002. This contract is for power delivered over SP-15 (South of Path 15) into Southern California from Company resources in the Eastern Control Area. The Company itself assigned the SCE wholesale sales contract to the Eastern Control Area. The assignment of wheeling expenses should follow the assignment of the wholesale sales contract. The assignment of the SCE ISO Charge reduces Western Control Area wheeling expenses by $7 million, which results in a reduction of the Washington allocated Net Power Cost of $1,567,370.

Q. What is your second change to wheeling expense assignments?

A. There are two items related to reserves, the "Idaho RTSA INCR Capacity" expense and the "Idaho RTSA –Other Serv" expense. These two items total $1,197,846. These expenses are related to bi-directional reserves on Idaho Power Company's transmission lines. As such, the cost should be split between East and West Control areas. I have assigned one-half of the cost for these items to the East. This results in a reduction of $598,846 in wheeling expenses assigned to the West or a reduction in Washington allocated Net Power Cost of $134,088.

Q. What are your other changes to wheeling expense assignments?

A. There are two wheeling expense items identified as the "Naughton Wheel" and The "Bannack Wheel." Both of these expenses relate to older interconnection agreements between Washington Water Power, Idaho Power, Montana Power, Pacific Power, and Utah Power. These interconnection agreements provide benefits to both control areas and should be assigned to both. I have assigned half of the $ 362,400 total expense associated with these items to the East. This results in a reduction of $181,200 in wheeling expenses assigned to the West or a reduction in Washington allocated Net Power Cost of $40,572.

Q. Are there any other reassignments of wheeling expenses that look appropriate for adjustment?

A. Yes. I looked at the $10.5 million annual expense associated with the item identified as "BPA Midpoint Medford." This large expense is for transmission rights on BPA's Midpoint Meridian transmission line. The line runs from Midpoint, in central Idaho, to the Medford, Oregon area. The Company has delivery service rights at various locations along the line. Rights along this line are also bi-directional. Although Staff recommends the use of a control area-based allocation methodology, the presence of some interconnection between the West and East has certainly been recognized. The rights of the Company associated with this transmission service warrant assignment to both control areas. However, I have not made an adjustment in this proceeding related to this contract. The sheer magnitude of annual expenses associated with this contract cause me to step back and recommend further evaluation before making an adjustment. This is a very conservative approach. I recommend that a more robust evaluation be carried out as part of the Washington islanding or stand-alone recommendation, with particular attention to the assignment of interconnection and exchange related wheeling expenses.

Q. What is the result of Staff's recommended adjustments?

A. The total result from changing the assignment of the firm wheeling expenses is a reduction of $7,961,246 in Western Control Area expenses, without any adjustments to the BPA Midpoint-Medford contract. This results in a reduction to the Washington Allocated Net Power Cost of $1,782,603, based on the 22.391 percent Control Area Generation West allocator.

Q. **Are there other firm wheeling or transmission expense issues that merit discussion?**

A. Yes. The Control Area Generation West (CAGW) allocator of 22.391 percent is a function of each jurisdiction's load characteristics. The Company's Washington customers are concentrated near Yakima and the Wallula to Walla Walla corridor. From a geographic perspective, these load centers are also reasonably near many of the larger generating resources within the Western Control Area, including the Company's Hermiston Project, the Lewis River Hydro Facilities, and the Mid-Columbia Projects. In the Western Control Area, the Company's service territory is integrated with the BPA network. The Company uses firm rights on the BPA transmission system to cover its service territory and to connect to markets.

Q. Why is this information of interest?

A. A significant portion of the total firm wheeling expense assigned to the Western Control Area, is related to BPA contract payments. It also is apparent that a significant portion of those expenses are necessary to serve areas of the Company's service territory in southern and northeast Oregon that are more isolated from generation resources or markets. In regards to the allocation of transmission expenses and resources within the Western Control area, one could ask whether it is appropriate to allocate costs to the jurisdictions only on the basis of jurisdictional loads. Several questions come to mind. Is an allocation method recognizing geography and distance to generation and markets more appropriate? Would an allocation method based on actual power flows be in the best interest of Washington customers? The answers to these questions have a significant effect on costs allocated to Washington. The allocator used in this docket results in 22. 391 percent of all Western Control Area transmission costs being allocated to Washington. Based on the initial $62.5 million of just firm wheeling expenses assigned to the Western Control Area, even a small 10 percent reduction (22.391% to 20.152 %) in the amount allocated to Washington results in a decrease in allocated firm wheeling expenses of approximately $1.25 million. It is not impossible to imagine that a change in this amount, or more, may be appropriate.

Q. Has Staff analyzed the Company's Western Control Area transmission system with an alternative allocation recommendation in mind?

A. No. The purpose of this discussion is simply to point out that the recommended adjustment is very conservative given the use of the control area-based allocation of expenses, and other adjustments that may be appropriate.

Q. Do you recommend any further adjustments to transmission costs in this proceeding?

A. No. I did review the Company's listing of transmission plant assigned to the control areas. The assignments were carried out based on geography and do not reflect any analysis of the actual use of the plant. At this time, with no studies available, I do not recommend any adjustments to transmission plant accounts. However, if the Commission chooses to adopt the control area-based allocation of transmission related costs, further studies should be performed prior to the development of Washington islanding or stand-alone rates.

Q. Is there another alternative that the Commission could adopt for transmission costs in this proceeding?

A. Yes. The adjustments discussed in my testimony are based on the Company's modeling of transmission costs by control area. If the Commission desires to continue the "common-carrier" or "postage stamp" approach to transmission service as part of the transition to determining Washington standalone costs, it may want to continue to adopt the allocation of transmission cost on a system-wide basis such as in the Protocol. If the Commission wished to adopt that methodology, and thus not adopt Staff's assignment changes, the initial firm wheeling expenses allocated to Washington would decrease to $6,705,346 (from Company response to Staff Data Request No. 4) from the initial amount (before Staff's recommended changes above) of $13,995,046 when assigned by control-area. Correspondingly, the amount of transmission net plant allocated to Washington (based on a system-wide allocation versus control area) would increase to $126,963,729 compared to $119,169,362. The adjustments recommended in my testimony would be moot. The net effect on Washington revenue requirement discussed earlier removes any adjustments because they are based on reassigning costs, which would not occur under the Protocol. This would essentially return the revenue requirement associate with transmission service to the Washington-allocated level in the Company's filing using the Protocol.

G. Market Cap Adjustment

Q. Please describe Staff's recommended "market cap" adjustment.

A. I recommend that additional energy sales from the Jim Bridger coal plant be inputted in the GRID Model to correct for market caps that are imposed on the Mid-Columbia market during low load hours.

Q. What is the basis for your recommended adjustment?

A. Using the control area-based cost allocation methodology results in Washington being allocated approximately 22.6 percent of fixed and variable costs of West Control Area resources. These resources include the Company's ownership or share of the Jim Bridger coal plant, Colstrip Units 3 & 4, Hermiston Cogeneration, James River Cogeneration, Swift Hydroelectric Project, Merwin Hydroelectric Project, Yale Hydroelectric Plant, and various other hydroelectric facilities in the Western Control Area. In addition, the Western Control Area is assigned the costs associated with numerous long-term wholesale purchases including the Company's share of long-term arrangements related to the Mid-Columbia Hydro contracts. Given the generation that is allocated to Washington, both long-term and short-term sales of energy are an important component in accessing the Washington allocated Net Power Cost.

The GRID model utilizes market caps during low load hours to control the volume of system balancing transactions. This limits the amount of energy that can be sold during the low load hours from low cost coal plants throughout the Company's system. This increases net power costs because the model will not carry out additional sales into the market. Recent operating statistics of the Bridger Coal Plant indicate that the plant operates at a higher level than modeled in GRID. Raising the market cap allows the plant to sell into the market during the low load hours, if profitable to do so.

Q. How did you determine the market cap effect related to the Bridger Coal Plant?

A. The GRID model is run using a higher market cap (200 MWs) for the Mid-Columbia market, which is the primary market for Bridger energy. The higher market cap effects the generation of other resources in addition to Bridger. The amount of increased Mid-Columbia energy sales tied to Bridger was obtained by calculating the increased energy production from the plant. The entire increase is assumed to be sales into the Mid-Columbia market. The revenue associated with the sales is determined by multiplying the incremental energy produced times the average sales price of low load hour energy in the Mid-Columbia market. The variable fuel costs related to the incremental Bridger generation is then subtracted to arrive at the net revenue for the increased sales from Bridger. The net revenue from system balancing sales due to incremental Bridger energy increases by $1,154,420. This revenue is assigned to the Western Control Area.

Q. What is the result of your recommended adjustment?

A. Western Control Area Net Power Costs decrease by $1,154,420, with the Washington allocated Net Power Cost decreasing by $258,486.

H. Miscellaneous Power Cost Study Adjustments

Q. Please describe corrections to the power cost study corrections that have been identified by the Company.

A. In response to data requests, the Company identified several errors in its filed power cost study that should be corrected. The Company indicated that it would reflect these corrections in its rebuttal testimony. Staff has reviewed the Company's summary of each error and recommends that the Washington allocated Net Power Cost be adjusted by the net effect of all of the errors that can be clearly assigned to the Western Control Area. Errors identified by the Company not discussed here are related to the Eastern Control Area. Staff has used the Company's representation of the effect on power supply costs for each of the corrections.

Q. Please describe each of the relevant errors and their effect on the Washington allocated Net Power Cost.

A. The first error relates to the correct number of water-years to use for determining normalized power supply costs. Staff's recommended methodology for using water year data to determine normalized power supply costs replaces this adjustment.

The first actual adjustment corrects for an error that did not remove reserve capacity upon expiration of the Colockum contract. This correction results in an increase in Net Power Costs attributable to the Western Control Area of $500,000. The effect on the Washington allocated Net Power Cost is a $111,955 increase.

The next adjustment corrects for changes in stream flow operating parameters for the Company's Merwin hydro facility due to licensing requirements that are reflected in the GRID model. Staff does, however, recognize that this adjustment is based on an "interim" agreement with the US

Fish and Wildlife Service. Any final agreement should be incorporated into the model at the earliest possible date. This correction results in an increase in Net Power Costs attributable to the Western control Area of $1.7 million. The effect on the Washington allocated Net Power Cost is a $380,647 increase.

The next adjustment corrects for the incorrect entry of "shape to load" attributes into the GRID model for the BPA Peaking Contract. This correction results in a decrease in Net Power Costs attributable to the Western Control Area of $1.2 million. The effect on the Washington allocated Net Power Cost is a $268,692 decrease.

The final adjustment corrects for the double counting of Redding Exchange energy. Short-term firm data included energy already accounted for in the long-term transaction data. This correction results in a decrease in Net Power Costs attributable to the Western control Area of $1.5 million. The effect on the Washington allocated Net Power Cost is a $335,865 decrease.

Q. The Company identified a correction associated with the inability to carry operating reserves due to an outage on the Cowlitz Swift 2 project. Do you propose an adjustment?

A. No. The Company identified a $3.6 million increase in power costs due to the inability to carry operating reserves on Swift 1. After the collapse of the Swift 2 diversion channel in April of 2002, the Company is forced to run the Swift 1 project as a run-of-the-river project to stay within the license requirements concerning the rate of change below the project. The project does not, therefore, have the ramping ability to provide reserves.

Staff recommends that no adjustments to power supply costs be made at this time relating to this project. The latest information indicates that the repair project is on schedule to be back in service on or before April 1, 2006. Rates in this proceeding will not take effect until the end of 200~~5~~4. Therefore, it is inappropriate to reflect the short-term effects of this event in future rates. However, Staff recommends that the Company be allowed to make a filing, if so desired, requesting recovery of extraordinary cost related to the outage. That filing should include the identification any insurance payments received or payments from other parties related to the project outage and identify the actual costs associated with the outage during the period in effect.

Q. What is the total recommended adjustments relating to the corrections identified by the Company?

A. The recommended corrections, in total, result in a decrease in Net Power Costs attributable to the Western control Area of $500,000. The effect on Washington allocated Net Power Costs is a $111,955 decrease.

I. Summary of Net Power Costs

Q. Please summarize Staff's recommended adjustments to Net Power Costs.

A. Exhibit No.___ (APB-6) shows the total Washington allocated Net Power Cost adjustments by account using the proposed control area-based allocation methodology rather than the Company's Protocol as the basis for inter-jurisdictional cost allocations. Staff's Washington allocated Net Power Cost totals $ 60,645,872. Not adopting Staff's adjustment reflecting the control area allocation of transmission costs would decrease Washington's allocated Net Power Cost by a net $5,507,098. This reflects an initial adjustment of $7,289,700, less the effect of Staff's $1,782,603 recommended transmission-related adjustments discussed above. The overall revenue requirement effect of these adjustments must then reflect the corresponding changes in plant assigned or allocated to Washington.

VIII. FIXED COST POWER SUPPLY AND TRANSMISSION ADJUSTMENTS

Q. Please describe any recommended adjustments to power supply and transmission related plant.

A. My recommended adjustments to the various power supply and transmission related plant accounts are reflected in the control area-based allocation model provided in the Company's response to Staff Data Request No. 213. That response reflects the assignment of the various power supply and transmission plant accounts based on control areas. The move from the Protocol's plant allocations to control area-based allocations results in a decrease of approximately $39.36 million in net plant or rate base related to power supply and transmission. The assignment of transmission costs based on control area alone, reduces Washington allocated transmission net plant by only $7,794,367. In the event the Commission does not adopt the control area assignment of transmission costs, Washington allocated net plant would increase by that amount, with the corresponding decrease in Washington allocated net power cost expense discussed above.

IX. OTHER POWER SUPPLY OR TRANSMISSION EXPENSES

Q. Please describe your recommended adjustments to other power supply or transmission expenses.

A. The Company is currently including costs related to the development of a Regional Transmission Organization or "RTO." The creation of the RTO is subject to regulatory approvals from the FERC, as well as the affected state commissions. The process to develop the RTO is ongoing, with a target to seat an Independent Board of Trustees by the end of 2004. Staff asked the Company to identify RTO-related expenditures for both the Company and outside services during the test year. The Company identified a total expense of $2,193,969 for outside services during the test year and $1,495,346 for total Company direct and incidental costs. I recommend that the Washington allocated amount of the total $3,689,315 test year expense be removed for retail rate making purposes. This results in an adjustment to the various accounts of $279,845. Staff witness Mr. Schooley describes the adjustment on an account-by-account basis. A full review of RTO development costs and the potential for their recovery should be an issue in the Company's RTO filing at the Commission.

Q. What is the basis for this adjustment?

A. These RTO-related expenses are not ongoing costs that should be recovered through the retail electric rates. There is no indication of how long or at what level these expenses will occur. They are expenses that should be recovered, if prudently incurred, through the appropriate RTO tariff. No benefits for retail electric customers have been demonstrated. In addition, the expenses have not been reviewed for prudence in the context of the development of an RTO. It is impossible to determine without a full review that the amounts were expended in the best interest of Washington ratepayers. This review needs to take place as part of any RTO filing before the Commission, with the recovery of development costs through RTO tariffs being an issue at that time.

Q. Does this complete your testimony?

A. Yes.