Exhibit No. ___TC (APB-1TC)
Docket Nos. UE-050684 and UE-050412
Witness: Alan P. Buckley
REDACTED VERSION

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP, d/b/a Pacific Power & Light Company, Respondent.	DOCKET NO. UE-050684
In the Matter of the Petition of PacifiCorp, d/b/a Pacific Power & Light Company for an Order Approving Deferral of Costs Related to Declining Hydro Generation	DOCKET NO. UE-050412

TESTIMONY OF

ALAN P. BUCKLEY

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

ISSUES: Cost Allocations, Power Supply, PCAM and Deferred Accounting Petition

CONFIDENTIAL PER PROTECTIVE ORDER

November 3, 2005

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I. OVERVIEW

A. Introduction

Q. Please state your name and business address.

A. My name is Alan P. Buckley. My office address is 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia, Washington 98504, and my e-email 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 the 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 WUTC 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 WUTC. I also 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) Provide background relating to inter-jurisdictional cost allocations;

2) Evaluate the "Revised Protocol," which is what PacifiCorp calls its proposed inter-jurisdictional cost allocation methodology;

3) Present Staff's recommended cost allocation methodology;

4) Present Staff's methodology of determining net power cost in the context of Staff's cost allocation methodology;

5) Evaluate the Company's proposed Power Cost Adjustment Mechanism or "PCAM;"

6) Address the prudence of PacifiCorp's resource additions; and

7) Address the Company's Petition in Docket No. UE-050412 for a Commission order approving deferral of costs related to declining hydro generation.

Q. How is your testimony organized?

A. My testimony is divided into six general sections. Section I contains this introduction, a summary of Staff recommendations, a summary of my testimony, and a discussion of key terms used in my testimony.

Section II is a discussion of the principles that should apply when evaluating a cost allocation method.

Section III provides a history of the allocation issue for PacifiCorp, including a description of what various PacifiCorp states have decided on that issue.

Section IV contains a description and critique of the Company's inter-jurisdictional cost allocation proposal, the Revised Protocol.

Section V discusses alternative cost allocation models Staff has analyzed

Section VI presents Staff's recommended allocation methodology and associated adjustments, as well as other potential adjustments and alternatives.

Section VII addresses other power supply issues, including the Company's proposed Power Cost Adjustment Mechanism, the prudence of resource acquisitions, and the Hydro Deferral Petition.

B. Summary of Recommendations

Q. How does Staff recommend the Commission decide the cost allocation issues in this case?

A. The Commission should adopt Staff's Amended Revised Protocol (with allocation-related power supply adjustments) proposal for purposes of this case only. The Commission should reject PacifiCorp's proposed Revised Protocol for purposes of determining inter-jurisdictional cost allocations.

The Commission should also order PacifiCorp to file its future general rate cases using an inter-jurisdictional cost allocation model not based on the system-wide, rolling-in of costs. Staff's preferred approach is to develop a Simplified Control Area Model in cooperation with the Company and other interested Washington parties.

Q. What does Staff recommend for Power Supply adjustments?

A. The Commission should adopt the allocation-related power supply adjustments summarized in my Exhibit No. ___ (APB-2). The net effect of these adjustments reduces Washington's Revenue Requirement by approximately $12.95 million. *See Mr. Schooley's Exhibit No. ___ (TES-3), page 20, total of lines 15, 16, 17 and 36 "Revenue Requirement Impact" column.*

Q. What does Staff recommend for the Power Cost Adjustment Mechanism (PCAM) PacifiCorp has proposed?

A. The Commission should reject PacifiCorp's PCAM proposal as filed. Staff is open to the development of a power cost adjustment mechanism in the context of the appropriate inter-jurisdictional cost allocation model.

Q. How does Staff recommend the Commission resolve the Company's deferred accounting petition in Docket No. UE-040512?

A. The Commission should allow the Company to recover a one time amount of $2,103,823 in deferred "excess" power costs for the period March 2005 through December 2005. This amount should be amortized over a three-year period, beginning April 2006, or from time that rates from this proceeding take effect, whichever is later.

The Revenue Requirement effect of this adjustment is presented in Mr. Schooley's Exhibit No. ___ (TES-3), page 20, line 18: "Hydro Deferral Recovery." The Commission should deny the deferral of additional "excess' power costs past the period identified above.

C. Summary of Testimony

Q. Please summarize the historical context of the cost allocation issues in this case.

A. Inter-jurisdictional cost allocations have been an issue for the Commission since the merger of Pacific Power & Light Company and Utah Power & Light Company in 1988. That merger combined a lower cost utility (Pacific Power) and a higher cost utility (Utah Power). The Commission recognized this discrepancy in costs between the two utilities divisions in its Order approving the merger in Docket No. U-87-1338-AT.

Since that time, the Commission has continued to support the development of an appropriate inter-jurisdictional cost allocation methodology. Recent events have highlighted the importance of inter-jurisdictional cost allocation issues. These events include the Utah Commission's unilateral decision in 1999 to base its future rate case revenue requirement on a system-wide, "rolled-in" method for allocating costs (thus effectively ending ongoing efforts at that time to develop an inter-jurisdictional methodology); the diverging load growth characteristics of the Company's system, particularly related to significant growth in Utah; and Oregon's direct access legislation; and the recent acquisition by the Company of a number of large generating resources to serve specifically identified needs.

Various efforts have been made to address these issues. The latest began in 2002, when the Company instituted the Multi-State Process (MSP) to develop an acceptable inter-jurisdictional cost allocation methodology. From Staff's perspective, the MSP was dominated by the goals of the Company's two largest jurisdictions, Utah and Oregon.

In any event, the MSP failed to develop a consensus allocation method. However, PacifiCorp eventually developed a proposal, primarily by working with its largest jurisdictions. The end result of that effort is the Revised Protocol now before the Commission in this proceeding. The Revised Protocol is an inter-jurisdictional cost allocation model based on the system-wide, "rolled-in" allocation of costs.

The Company has received approval from four of the jurisdictions for the Revised Protocol, although the Utah and Idaho commissions have adopted rate mitigation measures based on other methods. The Oregon commission has ordered PacifiCorp to develop a control area based allocation model for "comparative" purposes. Finally, there have been continued workgroup efforts as part of the Revised Protocol to further address some of the ongoing allocation issues.

Q. Please summarize your testimony addressing the review and analysis of the Revised Protocol.

A. The Revised Protocol is not in the public interest. The Company claims that the Revised Protocol is appropriate because the Company "plans and operates its system on an integrated basis," and that Company estimates of long-term revenue requirement effects are in an "acceptable range."

However, the Revised Protocol's system-wide, "rolled-in" allocation of the majority of the Company's costs does not reflect the way the Company plans and operates its system, nor how and why the Company has actually acquired resources.

Moreover, a proper cost allocation method should be justified by how it reflects cost causation principles, not how "acceptable" the results are based on the assumed accuracy of a forecast. These "results-based" analyses of future revenue requirement effects used by the Company to support the Revised Protocol have no relationship to whether the allocation method can actually match costs to the appropriate jurisdiction.

The Revised Protocol is inconsistent with how PacifiCorp has conducted its resource planning through the IRP and RFP processes. PacifiCorp's IRPs and RFPs clearly show: 1) That the Company's Eastern and Western control areas have separate and different needs and characteristics; and 2) The Company has planned for and acquired different resources to meet those separate and different needs of each area.

In the near-term, the Revised Protocol results in the allocation of costs, to Washington, for resources that PacifiCorp acquired and uses to serve the power needs of the fastest growing part of its service area: the Eastern Control Area, primarily Utah. Transmission constraints limit the Company's use of Eastern Control Area resources to serve Washington loads. If Washington ratepayers did not cause the need for the new resources, and there has been no meaningful demonstration of associated benefits from them, it is not appropriate to allocate the costs of those resources to Washington.

Finally, the Revised Protocol is complex and presents administrative burdens. If the Commission accepts the Revised Protocol for the long-term, that will result in a significant burden in the Commission's future administration of the Company's costs.

Based on Staff's review of the Revised Protocol and supporting documentation, Staff recommends that the Commission reject the Revised Protocol.

Q. Please summarize your testimony regarding the appropriate methodology for allocating inter-jurisdictional costs for this proceeding.

A. In attempting to resolve the issue of inter-jurisdictional cost allocations, Staff examined several different models. The models ranged from relatively simple models to more complex models. Unfortunately, none of these alternative models are fully developed and operational. However, once the Commission provides appropriate guidance in this case, Staff is prepared to develop a working model that satisfies the principles acceptable to the Commission with the full participation of the Company and customers.

In the meantime, Staff recommends that, for this case only, the Commission use Staff's Amended Revised Protocol, with allocation-related power supply adjustments, for purposes of determining Washington revenue requirements. The Staff's allocation-related adjustments relate to certain newly acquired generating resources, Mid-Columbia contracts, Seasonal Contracts, and Qualifying Facility costs.

The Staff's Amended Revised Protocol method is a compromise solution to address the most immediate problems with the Revised Protocol until a more robust, long-term solution can be developed. Alternatively, the Commission could reject the Company's tariff filing based on the lack of an acceptable inter-jurisdictional cost allocation methodology.

Q. Please summarize your testimony regarding power supply costs in the context of Staff's recommended allocation methodology for purposes of setting rates in this proceeding.

A. My Exhibit No. ___ (APB-2) summarizes Staff's recommended allocation-related power supply adjustments that form the basis for an Amended Revised Protocol. These adjustments are based on removing certain resources and contracts entirely from Washington's allocated share of net power costs; by changing the allocation factors to reflect a more acceptable treatment; or by re-calculating the effect of several QF contracts. I also considered, but did not make, additional adjustments related to various Eastside resources. For a number of reasons, I also propose that transmission related assets and costs continue to be treated in the same manner as in the Revised Protocol for purposes of this proceeding only. Staff is not proposing any additional net power supply expense adjustments. However, Staff intends to analyze any power supply adjustments proposed by other parties.

Q. Please summarize your testimony regarding PacifiCorp's proposed Power Cost Adjustment Mechanism, or PCAM.

A. The Company is proposing a power cost adjustment mechanism that tracks virtually all of its net power supply cost components, Westside and Eastside. The Company also proposes an earnings test that would determine whether or not the balances would actually be recovered. The Company claims that a PCAM is warranted because it has a large exposure to power cost variations, and the Company identifies some historical differences between actual power costs and power costs embedded in rates.

The Company's claims of power cost exposure are overstated. The majority of the Company's historical exposure to power cost variations is related to the Western energy crisis in 2001, not from normal variations in power supply. While the overall level of market prices has increased, volatility has not remained at energy crisis levels.

Moreover, the Company has ignored other factors that affect its exposure to power cost variations, such as the Company's participation in the wholesale market and the unexpected growth in Utah loads. The proposed PCAM would require the ratepayers to insulate the Company from power cost variations from these sorts of causes. That is not appropriate.

Finally, the proposed PCAM is too broad, it lacks incentives, and is it not consistent with the normalized power supply expense methodology used by the Company.

In any event, the Company's proposed PCAM is based on the use of the Revised Protocol for allocating variations to Washington customers. The Revised protocol is not appropriate, so the PCAM is not appropriate.

Staff can support a power cost adjustment mechanism under appropriate conditions. Staff is willing to work with the Company to develop a power cost adjustment mechanism that is limited, focused, efficient to administer, and consistent with the overall cost allocation methodology ultimately adopted by the Commission.

Q. Please summarize your testimony regarding the prudence of resource acquisitions.

A. The Company is requesting a prudence determination for a number of previously acquired resources, as well as the new resources included in power costs for the first time in this proceeding. The Company's cost allocation method is the primary driver for determining power supply and other costs that should appropriately be assigned to Washington customers. The Company continues to claim that a resource should be considered prudent for Washington if it has been determined to be prudent for the Company's system as a whole.

The Company is incorrect. A prudence determination necessitates an affirmative showing by the Company that each resource is needed and used and useful for serving Washington, and that it is the least cost option to meet Washington's needs.

It is Staff's position that the Commission need not address the prudence of Company resources not associated with providing service to Washington. This includes a number of resources whose cost allocation to

Washington is based on the use of the Revised Protocol and whose ultimate allocation is questionable under the appropriate long-term allocation method accepted by this Commission.

Q. Please summarize your testimony regarding the Company's deferred cost petition in Docket No. UE-050412.

A. The Company's Petition for an Order Approving Deferral of Costs Related to Declining Hydro Generation (or "Hydro Deferral Petition") in Docket UE-050412 was consolidated with this general rate case. The Company is requesting Commission approval to defer "excess" costs related to poor water conditions and reduced hydro generation beginning in March of 2005, and continuing until a new allocation mechanism is adopted. The Company has provided continued updates to its estimated deferral amount through year end 2005 based on the methodology it has proposed to track the "excess" costs. The Company's approach is not meant to be rigorous in its tracking of power costs related to reduced hydro generation.

Staff recognizes that a large portion of the Northwest has experienced severe drought conditions, particular in the area of the Company's Lewis River projects. Staff is also willing to consider the recovery of certain "excess" power resulting from the extreme hydro conditions experienced last winter.

However, Staff has made several adjustments to the Company's allocation methodology relating to Westside hydro resources, the Mid-Columbia projects. Also, existing rates were designed to recover some portion of power cost variability due to water conditions. Consequently, drought-related deferred power costs should only be considered "excess" and eligible for deferral when those costs are truly extraordinary. All of the costs PacifiCorp seeks to defer and recover do not qualify.

Therefore, Staff recommends the Commission allow the Company to recover a specific one-time deferral amount of $2,103,823, to be amortized over a three-year period.

D. Key Terms: "Rolled-in allocation," "Dynamic allocation," "Control Area," "Hybrid model," "and MSP"

Q. Please explain what the terms "rolled-in" allocation and "dynamic allocation" mean.

A. A "rolled-in" allocation method essentially treats the utility's resources as if they are available throughout its service area, *i.e.,* with no delivery constraints. Under a "rolled-in" allocation method, a portion of the cost (rate base and expenses) of each of the utility's resources is allocated to each state the utility serves.

"Dynamic allocation" means that the actual allocation factors being used are periodically re-determined based on changes in load and/or other characteristics, such as number of customers.

Q. Why is the term "rolled-in" allocation important in this case?

A. A fundamental characteristic of the Company's proposed Revised Protocol allocation method is that it "rolls-in" most of the Company's existing and new resources, including transmission-related expenses.

The Revised Protocol makes some exceptions for certain state-specific resources, and the actual amounts allocated to each state may change over time due to changes in loads or other characteristics.

However, the majority of the Company's resources are allocated as if they were available system-wide, with a portion allocated Washington, and every other PacifiCorp state.

Q. Please give some examples of specific projects that PacifiCorp's Revised Protocol "rolls-in" and allocates to each jurisdiction, including Washington.

A. Three examples are the Gadsby Peaker Project, the Currant Creek Project, and the West Valley Lease. These are gas-fired combustion turbine projects located in Utah. I describe and address these projects later in detail, including the fact that the Company acquired each of these resources to serve Utah loads, not Washington loads.

The Revised Protocol treats these projects as "System Resources" and allocates them system-wide. For example, the combined net rate base for the Gadsby Peaker and Currant Creek Projects is approximately $425 million.[1] The Revised Protocol allocates to Washington over $35 million of net rate base for these two projects,[2] plus a corresponding share of the annual operating and fuel expenses for these projects as well. Washington is also allocated approximately $1.3 million out of the total annual $16.5 million in capital lease expenses associated with the West Valley Lease, as well as an equivalent share of the annual operating and fuel expenses.

Q. Please define what a "control area" is, and how that term applies to PacifiCorp.

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[1] Gadsby: $73,655,218; Currant Creek: $346,940,256. Source: PacifiCorp's Response to Public Counsel Data Request No. 111B and Exhibit No. ___ (PMW-3), Tab 8, page 8.4.1.
[2] Gadsby: $6,086,324; Currant Creek: $29,430,019. Source: PacifiCorp's Response to Public Counsel Data Request No. 111B and Exhibit No. ___ (PMW-3), Tab 8, page 8.4.1.
3. Source: PacifiCorp's Response to Staff Data Request No. 220.

A. A "control area" is generally defined as the area containing an electrical utility network whose primary function is to balance energy generation and loads in that area, as well as regulating adjacent control area interconnection flow.

As I explain in more detail later, PacifiCorp presently has two control areas. One is called the Western Control Area, consisting of Washington, Oregon and California. I also refer to this as "Westside" or "the "West." The Company's other control area is called the Eastern Control area, consisting of Utah, Idaho, and Wyoming. I also refer to this as "Eastside" or "the East."

With the exception of a part of Wyoming, these control areas roughly reflect the geography of the pre-merger Pacific Power & Light operations (Western Control Area) and Utah Power & Light operations (Eastern Control Area).

Q. Please explain what the terms "Hybrid allocation method" and "Hybrid method" mean.

A. The "Hybrid allocation method" and "Hybrid method" are the general names given to an allocation method that was investigated in the Company's Multi-State Process (MSP). In theory, the Hybrid method assigns resources and costs between the Company's two control areas. In practice, the version of this model that is being developed reflects many compromises designed to mitigate the results of the model for some MSP participants. However, PacifiCorp continues to work on the Hybrid model due to an order from the Oregon Public Utilities Commission, which I describe later.

Q. What is the "MSP?"

A. "MSP" stands for Multi-State Process. The MSP is well documented in the Status Report included as Mr. Furman's Exhibit No. ___ (DNF-4). The MSP meetings were convened by PacifiCorp in 2002, and the meetings were attended by representatives from the commissions in states where PacifiCorp operates. The MSP continued through July 2003, by which time no consensus was reached among the participants as to the appropriate allocation mechanism to adopt for all states. The Company filed its original Protocol proposal in several states, including PacifiCorp's last Washington general rate case filing, Docket No. UE-032065, in December 2003.

Subsequently, a process outside the MSP continued between the Company, Utah, and Oregon, which resulted in the Revised Protocol proposal, which the Company filed as part of its rebuttal case in Docket No. UE-032065.

II. PRINCIPLES FOR FAIR INTER-JURISDICTIONAL COST ALLOCATIONS

Q. Has the Commission adopted a cost allocation methodology for PacifiCorp since the merger between Pacific Power and Utah Power in 1988?

A. No. Since that merger, all rate changes for the Company that have been approved by the Commission have been the result of negotiated settlements. This docket provides an opportunity for the Commission to give firm direction on its preferred inter-jurisdictional cost allocation methodology.

A. Nature of Cost Allocations

Q. What are "inter-jurisdictional cost allocations" and "interstate cost allocations," and why are they important?

A. The terms "inter-jurisdictional cost allocations" and "interstate cost allocations" refer to the allocation of a utility's costs among the jurisdictions in which that utility provides service, where the costs cannot be directly assigned to a single jurisdiction. In this case, the jurisdictions at issue are states, so I use the two terms interchangeably.

Inter-jurisdictional cost allocations are important for a utility that operates in more than one jurisdiction because, other than in a settlement context, they are necessary in order to develop the utility's costs for purposes of establishing rates for services the utility provides in a particular state.

Q. Please give a typical example of a utility cost that can be directly allocated or assigned.

A. An example of a directly assigned cost is the cost of the utility's distribution system. The cost of the utility's service drop to a residence, for example, is used to serve that customer, so the cost of that plant can be specifically identified and allocated, or assigned, based on situs, *i.e.*, to the state where the customer is located.

Q. Please give a typical example of a cost that cannot be directly allocated or assigned.

A. An example is a utility's power plant that provides electricity, without constraints, to a number of customers across several jurisdictions. An inter-jurisdictional cost allocation method is the means of allocating the cost of that plant among those customers, if the costs are found to be prudent based on a number of factors.

B. Cost Allocation Principles

Q. What principles should the Commission apply in evaluating the merits of an inter-jurisdictional cost allocation method?

A. An appropriate cost allocation method should be able to match the allocation of the costs of a service or facility with the customers benefiting from those services or facilities ("cost causation"), and it should be straightforward and efficient to administer. Cost causation reflects a most basic concept of fairness.

Q. Please provide some examples that explain the principle of cost causation.

A. The simplest example is one I gave earlier: distribution plant. The distribution lines and power poles a utility has installed in one state should be allocated to that state because those poles and lines would not be there but for the demands placed on the utility by the customers in that state. The customers in that state caused the utility to incur the cost of that service drop and benefits from its installation. An appropriate cost allocation method would allocate that service drop to that state.

In other words, it would not be fair for PacifiCorp's Utah customers to pay the cost of utility poles PacifiCorp provides to serve customers in Walla Walla, Washington.

Another example is when customer demand in a particular state causes PacifiCorp to add energy or capacity resources to serve that new load. In that circumstance, the other states should not be allocated the cost of those new resources, if the customers in other states did not cause the utility to incur the cost of those new resources, and if there are insufficient corresponding benefits that warrant a "rolled-in" allocation of costs.

In other words, it would not be fair for Washington customers to pay the costs of a generating facility PacifiCorp acquired because the Company needs to meet significant load growth elsewhere, and PacifiCorp has not demonstrated that the facility is needed by or is sufficiently beneficial to Washington.

Q. Does the basic fairness of applying cost causation principles apply even if the resource the utility acquired to serve the load in one state was acquired at lower than average cost, thus causing rates to go down in that state compared to others?

A. Yes. The fairness concept applies whether or not the cost of the new resource is lower than the average cost, or higher. For example, if PacifiCorp's costs to serve Washington increases or decreases, then all else equal, Washington rates should increase or decrease accordingly.

By the same token, if PacifiCorp's costs to serve another state increase or decrease, then all else equal, the rates in that other state should increase or decrease accordingly, but the rates paid by Washington ratepayers should not be affected.

Q. How should the Commission implement this cost causation, fairness concept in determining an appropriate methodology for allocating the cost of the electric resources of PacifiCorp?

A. The Commission should adopt a methodology that fairly assigns the cost of a resource to all jurisdictions, only if PacifiCorp has demonstrated that the resource: a) was prudently acquired to meet the needs of those jurisdictions; and b) can serve customers in all jurisdictions without significant constraints; is demonstrated to be least cost for all.

By the same token, to the extent PacifiCorp appropriately acquired a resource to serve customers in only one if its control areas, or in fewer than all of the states, the Commission should adopt a methodology that begins by assigning the costs of that resource to each state that caused PacifiCorp to incur that cost and that receives the majority of the benefits.

Q. Why is it important for PacifiCorp to justify its rate increase based on factors specifically applicable to Washington?

A. PacifiCorp's Washington customers should pay rates for electricity that reflect only those costs that can be reasonably identified as being prudently incurred and necessary to serve Washington's load requirements, at least cost. It is PacifiCorp's responsibility to demonstrate this.

Q. Is it surprising that the costs a utility incurs in different control areas would increase at different rates?

A. Not at all. It is entirely reasonable to expect that a utility will experience different cost pressure in different regions in which that utility operates. There are a number of reasons that one state, or region, could have difference cost pressures. Indeed, as I will explain later, the Company has recognized and identified several reasons for these differences in previous filings before this Commission. These include load growth differences, legislative actions such as Oregon's direct access initiative, as well as differing state regulatory policies regarding the acquisition of specific resources.

Q. Is it appropriate for a cost allocation methodology to reflect those differences?

A. Yes. Customers in each PacifiCorp state should pay rates that reflect, as directly as possible, the identifiable costs PacifiCorp incurs to serve them.

For example, if PacifiCorp realizes cost increases due to hydro re-licensing, the Company's new Mid-Columbia contracts, or load growth in Washington, and PacifiCorp prudently incurred those increased costs to serve Washington, then Washington ratepayers should be responsible for the recovery of those costs.

III. HISTORY OF THE COST ALLOCATION ISSUE

A. The Pacific Power/Utah Power Merger

Q, In your opinion, what is of primary significance in considering the impact of the 1988 merger between Pacific Power and Utah Power?

A. The merger combined a lower cost utility (Pacific Power) with a higher cost utility (Utah Power). While many merger synergy benefits have been spread among the Company and the states, it is also true that many potential synergies have not been realized.

For example, transmission constraints between PacifiCorp's Western and Eastern control areas continue to limit the Company's ability to ship power freely between East and West. As I explain later, this is confirmed by the manner in which the Company carries out its resource planning and acquisitions.

Q. Did the Commission address inter-jurisdictional cost allocation issues in the merger docket?

A. Yes. In that case, Cause No. U-87-1338-AT, the Commission addressed several significant allocation related 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. What cost allocation related claims were made by the Company in that merger docket?

A. Among other things, the Company testified that, "[t]he merger will not significantly increase the regulatory burden of the state and federal regulatory commissions."[3] The Company further assured the Commission that Washington ratepayers would not have to subsidize the immediate rate reduction the Company 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.

Testimony of PacifiCorp's policy witness Mr. Frederick Reed, Tr. 733, in Docket No. U-87-1388 AT.

Q. Did the Commission take these claims into consideration?

A. Yes. In its order approving the merger, the Commission expressed its concern that ratepayers needed to be protected because Pacific Power was a lower cost utility than Utah Power:

> Staff witness Folsom correctly points out the discrepancy in average system cost between Pacific Power and Utah Power. The Commission continues to be concerned about the effects on Pacific's ratepayers of merging with a higher cost system, and believes the integration of the power supply function for the two companies should be done in a manner consistent with

[3] *Rebuttal Testimony of Fredrick Reed, Cause No. U 87-1338-AT, Exhibit T-43, at 1, line 29 through 2, line 1.*

> 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.

Second Supplemental Order in Docket No. U-87-1338-AT (July 15, 1988) at 14.

Q. How have PacifiCorp's least-cost plans addressed this cost difference between the Pacific Power service area and the Utah Power service area?

A. Based on my evaluation of PacifiCorp's least cost planning process since 2001, for planning purposes, PacifiCorp for the most part plans separately to meet the separate needs of the two areas. However, the Company's Revised Protocol fails to reflect this fact. I discuss these issues in detail in a later section of my testimony.

Q. Did the Commission in that merger docket urge the parties to address inter-jurisdictional issues after the merger was accomplished?

A. Yes. The Commission accepted the Company's agreement to convene a jurisdictional allocation committee with all involved states within six weeks of final approval of the merger. *Id. at 15, Finding of Fact No. 5.*

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

A. Yes. The PacifiCorp Inter-jurisdictional Taskforce on Allocations ("PITA") meetings convened. However, that process was effectively undermined by a 1999 decision by the Utah commission in a PacifiCorp rate case to "roll-in" all of PacifiCorp's resources for purposes of setting rates in Utah. The PITA meetings were unsuccessful.

B. PacifiCorp's Structural Realignment Proposal (SRP)

Q. After the PITA process ended, what allocation-related initiative did PacifiCorp undertake?

A. In 2000, PacifiCorp initiated Docket No. UE-001878, which I call the "Structural Realignment Proposal," or SRP. The SRP was PacifiCorp's request for a Commission order authorizing the Company to be restructured into six separate state electric companies, a generation company and a service company. I have attached an excerpt of the Company's Joint Application in Docket No. UE-001878 as Exhibit No. ___ (APB-3).

In its Joint Application at page 21, lines 2-4, the Company stated that the "existing mechanisms for the inter-jurisdictional allocations of the Company's costs are clearly broken." As an example, the Company specifically mentioned the fact that even though it sold its share of the

Centralia Plant and Mine at well above book value, the Company suffered a loss because after each state allocated the gain, more than 100% of the gain had been allocated. The prospect of similar issues arising in the future led the Company to make the SRP filing. *Exhibit No. ___ (APB-3) at 21, lines 4-17.*

Q. What other issues did the Company cite in its Application as reasons why it filed the SRP?

A. The Company cited many unresolved jurisdictional issues: the diverse views of its regulators; the appropriate nature and timing of direct access; the desirability of load growth and how any such growth should be met; enthusiasm about renewables and demand side management measures, and how to pay for them; the preference of one type of generating resource over another (*e.g.*, some states favored 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.

Q. Have those issues been resolved?

A. No. They remain unresolved issues today.

Q. Please describe the basic features of the Company's SRP.

A. In general, the SRP would have split the Company into eight separate entities. PacifiCorp would retain 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 be allocated among six new state electric companies.

One intriguing aspect of the proposal from the perspective of this case was PacifiCorp's proposal that each state would use a power purchase contract to acquire the necessary power supply to serve utility customers in that state. For example, a purchased power contract could provide 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 SRP docket?

A. On April 5, 2002, the Company filed a Motion for Voluntary Dismissal, Without Prejudice, in order to facilitate the Washington participation in the MSP. The Commission granted that motion in its Order of Dismissal dated April 8, 2002.

C. PacifiCorp's Sale of the Centralia Plant and Mine

Q. Earlier you mentioned the Company's sale of its interest in the Centralia Plant and Mine. Why is that sale relevant to the history of the allocation issue in Washington?

A. It is an important issue for two reasons. First, as I testified regarding the SRP docket, PacifiCorp actually sustained a "loss" as a result of that sale, due to differing jurisdictional treatments of the gain.

Indeed, even though the Centralia Plant and Mine did not serve Utah customers, the Utah commission adopted a "rolled-in" allocation methodology that allocated the gain from the sale of the Plant and Mine on a system-wide basis. This resulted in a share of the gain being allocated to Utah, and thus more than 100 percent of the gain was allocated among the states.

As I mentioned earlier, this was a "straw that broke the camel's back" as far as inter-jurisdictional allocations were concerned.

The second reason this sale is important background information for this case is because the Company sold the Centralia Plant and Mine in part because new resources were not needed in the Western Control Area. In other words, the fact that the Company disposed of a large, existing resource in the Western Control Area (Centralia), and then proceeded to acquire several large, new resources in the Eastern Control Area, is an excellent indication that the Company's system is not well integrated between East and West.

This means that an allocation method like the Revised Protocol, that "rolls-in" the costs of resources for allocation to all states, is a poor choice for allocating PacifiCorp's costs between states.

D. PacifiCorp's Multi-State Process (MSP)

Q. What is the Multi-State Process, or "MSP?"

A. The Multi-State Process, or MSP, is the name PacifiCorp gave to a series of meetings between PacifiCorp and staff personnel from the regulatory commissions in states where the Company operates.

Q. Please briefly describe the MSP.

A. The MSP involved joint discussions regarding appropriate inter-jurisdictional allocation methodologies for the Company. A goal was to reach a consensus among the states as to an appropriate cost allocation methodology. The MSP began in 2002 and ended in July 2003, when no consensus was reached among the participants as to the appropriate allocation mechanism for all states.

Q. Did the Commission require discussions in addition to the MSP?

A. Yes. In its Order No. 06 in Docket No. UE-032065, the Commission accepted the Settlement Agreement's condition that discussions in Washington be initiated that were aimed at developing an agreed-upon methodology for inter-jurisdictional allocations.

Q. Did these discussions pursuant to the Commission's Order in Docket No. UE-032065, result in any consensus regarding inter-jurisdictional cost allocations?

A. No. However, the discussions did result in a Status Report prepared by the Company that provides a brief overview, from the Company's perspective, of the Multi-State Process (MSP), the orders on allocation issues in the other states, and recommendations for future action.

Q. What are Staff's perspectives on the overall Multi-State Process and the various jurisdictional filings leading up to this proceeding?

A. From a Staff perspective, the entire MSP and jurisdictional filing process can be summarized by a few observations:

1. No consensus was reached by the participants as to an appropriate cost allocation method;
2. Much of the Protocol and the Revised Protocol were designed to address the needs and goals of the Company's two largest jurisdictions (Oregon and Utah);
3. The MSP used results-based analysis to evaluate allocation issues. Under this analysis, a proposal was deemed "acceptable" based on minimizing the revenue requirement effects across states, without direct consideration of cost causation principles;
4. The Protocol and Revised Protocol proposals are essentially variations of the "rolled-in" methodology advocated by Utah as a method to spread to all PacifiCorp states the costs of significant new resources, with some adjustments for embedded hydro resources and other items;
5. The commission orders on cost allocation methodology in the Company's two largest jurisdictions, Oregon and Utah, resulted in major conditions, including revenue requirement caps based on a full "roll-in" method (Utah) and a directive that PacifiCorp develop

another non-“rolled-in” based method as a tool for ongoing comparisons (Oregon). In addition, Idaho imposed a four-year rate cap based on a full “roll-in” method;

6. The Company failed to act on the suggestions of Commission Staff or other interested parties regarding alternative cost allocations methods. Instead, the Company chose to file the Revised Protocol proposal in this general rate case.

Q. What allocation principle was important to Staff during the MSP?

A. The principle of cost causation.

Q. If a cost allocation method allocates costs and benefits based on principles of cost causation, might that result in some states being responsible for significantly more costs and benefits than other states?

A. Very definitely. For example, Staff recognizes that under some future resource acquisition scenarios, greater costs will be allocated to Washington, such as hydro re-licensing, and that Washington should be willing to take the risk and accept the outcome from a principled position on those issues.

By the same token, states with high load growth, such as Utah, which causes PacifiCorp to incur the costs of new generating resources, should be willing to take the responsibility for paying the cost of that growth.

E. Decisions on Allocation Methods by Commissions in Other PacifiCorp States

Q. What is the status of the Revised Protocol in the other states PacifiCorp serves?

A. The utility commissions of Oregon, Utah, Idaho and Wyoming have issued decisions accepting or approving the Revised Protocol, but many have imposed significant conditions. The California commission has not yet issued a decision on the Revised Protocol.

Q. Is ratification of the Revised Protocol by the Commission necessary for its use by PacifiCorp in other states?

A. No. By its terms, use of the Revised Protocol is only conditioned upon the final ratification, without deletion or material change, by Oregon, Utah, Wyoming, and Idaho. *Exhibit No. ___ (DLT-2) at 14, Section XIII.D.* The Revised Protocol also provides that: "The Company will continue to bear the risk of inconsistent allocation methods among the states." *Id. at 15, last sentence.*

Q. Is it reasonable for the Commission to consider how other states have dealt with the Revised Protocol?

A. Yes. However, the Commission's primary concern should be to adopt a cost allocation method under which Washington customers only pay rates that are fair, just and reasonable.

For example, assume each state adopted a consistent "rolled-in" cost allocation methodology, whereby the rates in each state would reflect a share of each resource the utility acquired. If the utility acquired a specific resource to serve customers in one state, the "rolled-in" method would not be fair to the other states that did not cause that resource to be acquired.

Q. Does PacifiCorp suggest that the other states in which it serves have reached substantial agreement regarding an inter-jurisdictional cost allocation methodology?

A. Yes. PacifiCorp witness Mr. Furman testifies that the commissions in the states of Idaho, Oregon, Utah and Wyoming, have adopted the Revised

Protocol. He also testifies these states comprise 90% of the Company's retail revenues. *Exhibit No. ___T (DNF-1T) at 27, lines 9-13.*

Q. Does Mr. Furman identify any conditions imposed by those commissions that adopted the Revised Protocol?

A. No.

Q. Did any of those state commissions impose conditions on their acceptance of the Revised Protocol?

A. Yes. The commissions in Idaho, Oregon, and Utah have issued orders adopting the Revised Protocol with conditions apparently designed to "protect" customers from unacceptable results from that methodology. The Wyoming Commission approved the Revised Protocol without significant conditions.

Q. What conditions did the Idaho Public Utilities Commission impose?

A. The Idaho PUC approved a settlement that contained "rate mitigation measures," apparently consisting of PacifiCorp's promise that "until March 31, 2009, the Company's use of the Revised Protocol will not result in rates in Idaho that exceed 101.67 per cent of the amount that would result from use of the Rolled-In method." The Idaho PUC observed that according to PacifiCorp, this gave Idaho customers the benefits of resolution of MSP issues, but "insulated [them] from any major near-term rate impacts associated with it."[4]

Q. What conditions did the Oregon Public Utilities Commission impose?

A. The Oregon PUC ordered PacifiCorp to file a "fully functional Hybrid Method no later than December 1, 2005" as an option for the commission to consider.[5] The commission agreed that the Hybrid Model "should not be abandoned." *Order at 12.*

The commission also stated it wished to use the Hybrid Model as well as the Modified Accord, as comparators to the Revised Protocol in the future, and ordered PacifiCorp to file its annual reports and general rate case filings under all three methods. *Order at 13, ¶ 3.*

Finally, the commission stated it would "like the [MSP] Standing Committee to study variations of the Hybrid Method as a means to eliminate cost shifting." *Order at 12.*

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[4] *Re Investigation of Inter-Jurisdictional Issues Affecting PacifiCorp, d/b/a Utah Power & Light Company,* Case No. PAC-E-02-3, Order No. 29708 (Idaho PSC, February 28, 2005) at 6-7.

[5] *Re PacifiCorp Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol,* in Docket UM 1050, Order No. 05-021 (Oregon PUC, January 12, 2005) at 13, ¶ 2.

Q. What conditions did the Utah Public Service Commission impose?

A. The Utah PSC approved a settlement stipulation that called for various rate mitigation measures designed to limit the impact of the Revised Protocol compared to a full "rolled-in" method.[6] For example, the commission imposed a "Rate Mitigation Cap" that can restrict the Company's revenue requirements based on the results of a full "rolled-In" allocation method. The commission also stated that the full "rolled-in" allocation method "remains a valid benchmark to judge the reasonableness of future rates in Utah and [we] will require the Company to continue to file Rolled-In rates." *Order at 40.*

Q. Do other states benefit from a "rolled-in" method, compared to a method that allocates costs based on cost causation?

A. Yes. For example, Utah clearly benefits from a system-wide, "rolling-in" of the costs of new resources, which results in allocation to all states the costs of new resources that PacifiCorp acquired to serve Utah.

Oregon benefits from the Revised Protocol's treatment of the Company's Mid-Columbia hydro contracts and the treatment of Direct

[6] *Re Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket No. 02-035-04, Report and Order (Utah PSC, December 14, 2004) at 8, ¶¶ 1-3.

Access programs. I discuss the Mid-Columbia contracts issue in detail later in my testimony. Under the Direct Access treatment, Oregon is the sole beneficiary of credits that PacifiCorp may obtain through the sale of "freed-up" resources; resources that if rolled back into the allocation pool would provide benefits to other states.

Q. Has the Company made projections of the cost to PacifiCorp of the rate cap mechanisms currently in place in Idaho and Utah?

A. Yes. The Company's Confidential Response to ICNU Data Request No. 2.133 is included as my Exhibit No. ___ (APB-4C). This response shows there are significant near-term costs to the Company in accepting the rate cap mechanisms as part of the settlements in Idaho and Utah.

IV. PACIFICORP'S REVISED PROTOCOL METHOD FOR ALLOCATING INTER-JURISDICTIONAL COSTS

A. Description of PacifiCorp's Revised Protocol Method

Q. What allocation method does PacifiCorp propose in this case?

A. PacifiCorp proposes a method it calls the "Revised Protocol" because it is revised somewhat from the inter-jurisdictional allocation method called the

"Protocol," which the Company proposed in its last general rate case, Docket No. UE-032065.

Q. Is this the first Commission docket in which the Company has proposed the Revised Protocol?

A. No. PacifiCorp first introduced the Revised Protocol as part of its rebuttal testimony in that same docket. However, Staff was not able to fully analyze the Revised Protocol in that case, given the procedural schedule.

Q. Are the Company's "Protocol" and "Revised Protocol" methods substantially similar?

A. Yes. For example, in both methods, the Company assigns the costs of distribution facilities and certain state-mandated programs to the state that caused the Company to incur those costs. In both methods, the majority of other costs are allocated on a "rolled-in" basis, using different allocation factors for different kinds of costs.

However, there are differences in the treatment of hydro generating facilities and Mid-Columbia contracts, as well as the treatment of Qualifying Facilities. For example, the Revised Protocol "rolls-in" the benefits of the Company's Mid-Columbia contracts to both the former Pacific Power states

(Washington, Idaho, Montana and Oregon) and the former Utah Power states (Utah and Wyoming). The Protocol allocated those contracts to the former Pacific Power states only.

Q. Where does the Company provide and describe the Revised Protocol?

A. The text of the Revised Protocol is Mr. Taylor's Exhibit No. ___ (DLT-2). Mr. Taylor also describes the Revised Protocol in detail in his testimony, Exhibit No. ___T (DLT-1T).

Q. Do you describe all the details of the Revised Protocol in your testimony?

A. No. As I indicated earlier, Company witness Mr. Taylor describes the Revised Protocol in great detail in his testimony, Exhibit No. ___T (DLT-1T). I will not repeat that description.

My testimony focuses on the issues that concern Staff, namely, how the Revised Protocol's fundamental "rolled-in" allocation method does not reflect cost causation principles.

While the Commission should reject the Revised Protocol on that basis alone, I also address other, more specific problems with the Revised Protocol. These problems include the inappropriate manner in which the Revised

Protocol allocates the costs of existing and newly acquired resources and purchase power agreements.

B. Critique of the Company's Support for the Revised Protocol

Q. Please summarize the primary support PacifiCorp offers for adopting the Protocol in this proceeding.

A. The primary support PacifiCorp offers for the Revised Protocol consists of results-based analyses. PacifiCorp offers future revenue requirements studies, studies comparing Revised Protocol results to results of other methods, and studies comparing the sensitivity of the Revised Protocol to different types of risks.

More generally, PacifiCorp offers the testimony of Mr. Furman who says the Revised Protocol is equitable for customers in all states and for shareholders. He goes on to state that the Revised protocol is workable, responsive, and encourages continued operation of PacifiCorp's system as an integrated whole. He also claims that commissions together <u>must</u> set rates using allocation methods that "add to 100 percent" in order for the Company to have a reasonable opportunity to earn its authorized rate of return. *Exhibit No. ___T (DNF-1T) at 28, lines 15-17.*

Q. Does the Revised Protocol itself acknowledge that "results" rather than cost causation will determine whether that method is sustainable?

A. Yes. The Revised Protocol states: "A party's initial support or acceptance of the Protocol will not bind or be used against any party in the event that unforeseen or changed circumstances cause that party to conclude that the Protocol no longer produces just and reasonable <u>results</u>." *(Emphasis added). Exhibit No. ___ (DLT-2) at 14, lines 9-13.*

Q. During the MSP, what was the primary method of evaluating the various allocation proposals that ultimately led the Company to propose the Revised Protocol?

A. Beginning in 2002, and continuing in this proceeding, the Company has relied primarily upon future estimated revenue requirement impact studies to support the Revised Protocol. Mr. Duvall concedes that the revenue impact studies PacifiCorp carried out as part of the 2002 MSP "laid the foundation" for both the Protocol and Revised Protocol. *Exhibit No. ___T (GND-1T) at 9, lines 15-16.* He also describes how the same type of revenue impact studies were used to evaluate two allocation methods initially favored by various MSP participants - the Dynamic (or "rolled-in") allocation method and the Hybrid (or control area-based) allocation method. *Id. at 11-14.*

Q. What is the general nature of these future revenue requirement studies?

A. Generally, these studies evaluate the impact on revenue requirements in each state due to changes in allocation methodologies. The studies use 15 years of prospective results of operations as generated by the Company's Revenue Forecasting Model.

Q. What future revenue requirement studies does PacifiCorp provide in this case?

A. PacifiCorp provides a future revenue requirements study in Mr. Taylor's Exhibit No. ___ (DLT-5). In that exhibit, PacifiCorp estimates the impact of the Revised Protocol on future State revenue requirements. The Company concludes that "the revenue requirement impacts of adopting the Revised Protocol are within an <u>acceptable range</u>." *(Emphasis added). Exhibit No. ___T (DLT-1T) at 38, line 4.*

In Exhibit No. ___ (DLT-6), PacifiCorp compares Washington's revenue requirement under the Revised Protocol proposed in this case, with the revenue requirement under the Modified Accord methodology. The

Company uses this comparison to support a claim that Washington ratepayers are better off under the Revised Protocol.

Finally, Mr. Duvall provides support of the Revised Protocol based on past MSP analyses and load growth considerations. *Exhibit No. __T_ (GND-1T) at 8 through 24.* Mr. Duval provides revenue requirement impact studies in this proceeding in his Exhibit No. ___ (GND-3).

Q. If PacifiCorp's opinion is correct that the Revised Protocol produces estimated revenue requirements results in an "acceptable range," is that a good reason for choosing that method?

A. Not necessarily. If the cost allocation methodology is theoretically sound in that it correctly reflects cost causation, and it is straightforward and efficient to administer, then the results should be followed, regardless whether the results are deemed "acceptable" by some measure, in someone's opinion. If the cost allocation method is sound, it should not need to be changed, or be subject to conditions, caps or other qualifiers to produce rates that are fair, just, and reasonable.

Indeed, the fact that three states have required significant conditions before they will accept the Revised Protocol is evidence that the Revised

Protocol is not theoretically sound, it is not straightforward, and it is not efficient to administer.

Q. Are there any other problems with PacifiCorp's use of future revenue requirements studies to justify the Revised Protocol?

A. Yes. These studies present estimated future revenue requirements, which may or may not prove to be accurate, and they are based on a number of pricing and other assumptions which may also drive the results.

Moreover, while a commission should be informed about possible revenue requirements impacts of a cost allocation methodology, that is secondary to the primary goal of a cost allocation methodology: to allocate costs fairly, based on cost causation.

Staff continues to be concerned that other participants to the MSP, including the Company, have focused on a results-based, scenario analysis in evaluating, and ultimately choosing among the various cost allocation proposals, without first assuring that the cost allocation method properly reflects cost causation in the first place.

In other words, the primary emphasis of PacifiCorp's analyses is how each state's future revenue requirements might be affected by the various allocation methods given various scenarios and assumptions, rather than on how the methodology best reflects cost causation principles by recovering costs from those customers causing the costs.

Q. Can you give an example how the cost causation principle should be primary, and the results secondary?

A. Yes. Assume a utility operates in three states: States A, B and C. State A has high load growth and States B and C have low load growth. The load growth in State A causes the utility to build new power plants to serve State A. Assume the cost of the new power plants was significantly higher than the cost reflected in current rates.

If cost causation principles are the focus, the utility would allocate the cost of the new plants to State A. One consequence will be that the rates in State A should go up, perhaps significantly. The focus of regulation in State A would then be on how to accommodate that result through other efficiencies, demand management, and so forth.

Q. What happens in that example if revenue requirements is the focus, rather than cost causation?

A. If the focus is on revenue requirements impacts, the utility would search for an allocation method that "smoothes" the rate increases in State A, by shifting some costs to States B and C which, under a cost causation-based methodology, would not be borne by those states. That allocation method would be justified on the basis of relative rate impacts, not cost causation principles.

It is Staff's position in this case that cost causation principles should drive the selection of the cost allocation method, not future revenue requirements analysis, and a company's view as to what revenue requirements impacts are in an "acceptable range."

Q. In the MSP, did PacifiCorp evaluate the Revised Protocol by comparing it to other methods?

A. Yes. Earlier in the MSP, the so-called "standards" of comparison were a full "rolled-in" study and a study based on earlier attempts at a consensus method. The Company claimed that by comparing the results of the Protocol to the results generated by these other methods, each state could assess the revenue impact that different changes would have on the state.

Q. Are these comparisons meaningful?

A. No. Since the Pacific Power and Utah Power merger, the Commission has not adopted either the "rolled-in" allocation methodology, or any other method for purposes of determining rates, outside of a settlement agreement. Consequently, PacifiCorp is using these two unapproved methods to evaluate yet a third unapproved method: the Revised Protocol. That is not a sound approach for evaluating a cost allocation method.

Q. You also mentioned that PacifiCorp was relying on risk comparison studies. Please describe these studies.

A. Mr. Duval provides a risk analysis in his Exhibit No. ___ (GND-4). In that analysis, he compares future risks between the Hybrid and Dynamic proposals based on a number of scenarios and sensitivities. He then 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 No. ___T (DNT-1T) at 14.*

In these risk analyses, the Company considered scenarios including losses of load, responses to 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. How should the Commission use these Company risk analyses?

The Commission should give these risk analyses no weight. While the analyses discussed by Mr. Duvall may be interesting from an academic viewpoint, inter-jurisdictional cost allocations should be based on a proper 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.

In other words, a particular method's sensitivity under various "what if" scenarios should not form the basis to favor one allocation methodology over another. Rather, cost causation should be the focus. Cost causation is not the focus of PacifiCorp's revenue or risk analyses.

Q. Should the Commission also give no weight to the revenue requirement studies offered by PacifiCorp?

A. Not necessarily. However, the Commission's selection among interstate cost allocation methods should not be based on which one might minimize future revenue requirements. The Commission's choice should be based on which method accurately reflects cost causation principles, *i.e.*, which method fairly identifies the costs PacifiCorp has prudently incurred to serve Washington customers.

Staff is ready and willing to recommend that Washington customers pay rates that reflect the risks associated with PacifiCorp's Washington operations. However, Staff cannot recommend that costs or risks caused by other jurisdictions be shifted to Washington, or that Washington ratepayers should bear costs the Company cannot demonstrate as being caused by Washington operations, simply because in the Company's opinion, its studies show a "modest" or "acceptable" impact.

Q. What conclusions are appropriate to draw based on the Company's support for the Revised Protocol?

A. The focus of the Company's support for the Revised Protocol is the palatability of its results, not whether the method accurately reflects cost causation. This offers the Commission no assurance that Washington ratepayers are properly paying their fair share of the Company's costs.

C. The Revised Protocol Method Compared to How PacifiCorp Operates its System

Q. How is the manner in which PacifiCorp operates its system relevant to determining the appropriate cost allocation method?

A. The manner in which the utility's costs are allocated should be consistent with the manner in which the utility operates the system. How the utility operates its system is an excellent indicator of how that utility incurs costs and how to assign those costs. The validity of the Revised Protocol depends in large part on whether the Company's system is in fact operated as an integrated whole, in a manner sufficient to justify the system-wide, "rolling-in" of costs. As I explain below, the facts demonstrate that the Company's system is not operated in a sufficiently integrated manner to warrant the Revised Protocols allocation methods.

Q. How is this section of your testimony organized?

A. First, I show how PacifiCorp's testimony defends the Revised Protocol based on assertions about how the Company operates its system. Second, I provide the details surrounding the actual physical constraints on the Company's system. Finally, I explain why the manner in which PacifiCorp operates its system does not support the Revised Protocol methodology.

1. PacifiCorp defends the Revised Protocol based on assertions of how the Company operates its system

Q. Has the Company defended the Revised Protocol based on assertions regarding how the Company operates its system?

A. Yes. For example, Mr. Duvall provides a description of the Company's system as background to his support for the Revised Protocol's system-wide, "rolled-in" cost allocation methodology. He states: "Depending upon the load requirements, resource availability, and market prices in each control area, the Company is able to transfer power from east to west or west to east to minimize total system costs in each hour." *Exhibit No. ___T (GND-1T) at 6, lines 5-7.*

Mr. Duvall acknowledges that PacifiCorp is "limited by transmission constraints and operates its system on an integrated basis with two control areas." However, he goes on to claim: "In the real world of PacifiCorp's six-state integrated system, cost allocation issues for generation and transmission costs are far more complicated than distribution costs and potentially contentious because the system has some attributes of a single system serving six states and some attributes of two separate systems serving different regions." *Exhibit No. ___T (GND-1T) at 3, line 20 to 4, line 3.*

Mr. Duvall offers the following conclusion:

> At a more general level, 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 if that is the least-cost, least-risk option for the total system and for PacifiCorp's Washington customers*.

(Emphasis added). Exhibit No. ___T (GND-1T) at 7, lines 12-17.

Q. Do these statements by Mr. Duval accurately reflect how PacifiCorp operates its system?

A. No. This testimony, if accepted without critical analysis, might lead one to conclude that most of PacifiCorp's new resources are capable of serving customers system-wide, and that for the most part, PacifiCorp plans and operates its system on a total system basis.

However, as I explain below, PacifiCorp cannot operate on a total system due to significant constraints on the Company's ability to transfer power between the Eastern and Western Control Areas.

Not only does PacifiCorp not operate on a total system basis, but as I explain in a later section, PacifiCorp does not plan on a total system basis, either. Rather, PacifiCorp's has targeted many of its new resources to the high growth areas located in the Eastern Control Area, primarily Utah.

Q. Are the Company's Eastern and Western Control Areas interconnected?

A. Yes, they are interconnected. However, the critical issue is whether the extent of interconnection justifies a cost allocation method that "rolls-in" all of the Company's resources, and then allocates them to all states.

For example, practically speaking, the entire Western United States is electrically "interconnected" through many control areas. However, that does not mean the Commission should accept a "rolled-in" allocation to Washington of the cost of resources built to serve the City of Phoenix, for example.

Even when evaluating the costs of a single company such as PacifiCorp, it is imperative that the nature of the interconnections between the two control areas, along with the actual planning and acquisition criteria related to those, be considered when assigning costs to the various jurisdictions for ratemaking purposes.

Q. Please summarize why it is critical for the Commission to examine the manner in which PacifiCorp actually operates its system.

A. Simply put, if PacifiCorp does not operate its system in a manner consistent with the assumptions of the Revised Protocol, the Revised Protocol lacks a rational basis.

Staff will show that under the Revised Protocol, Washington is being assigned the costs of PacifiCorp resources that serve loads in areas such as Utah's Wasatch Front, but transmission constraints prevent that power from being used in Washington. At the same time, due to the dynamic allocation feature of the Revised protocol, Utah is being assigned a greater portion of cheaper Western resources as its load grows at a more rapid pace in comparison to the other states.

This is ample reason for rejecting the Revised Protocol.

2. *The ability of PacifiCorp to transfer power between its Eastern and Western Control Areas*

Q. Can PacifiCorp transfer power between its Eastern and Western Control Areas?

A. Yes, the Company has some limited transfer capability between control areas.

Q. Has PacifiCorp provided an exhibit that helps explain the nature of the interconnection and transfer capabilities between the control areas?

A. Yes. Mr. Duvall's Exhibit No. ___ (GND-2) provides a transmission topology map which PacifiCorp uses for its modeling efforts. While this map represents the PacifiCorp system for purposes of modeling, not actual operations, it confirms that PacifiCorp's ability to transfer power between control areas is significantly constrained.

The diagonal dotted line on that exhibit shows the boundary of the Company's East and West control areas. The circles or "bubbles" show the various resources the Company has. The arrows emanating from each bubble show where power can be transferred, and the amount and nature of the power that can be transferred.

Q. How does the Company describe the transfer capability between the Company's East and West control areas?

A. In his direct testimony, Mr. Duvall describes the maximum transfer capability between the various "bubbles" used in the Company's power supply model. He claims that the maximum transfer capability from West to East is 1,171 megawatts, and from East to West, the maximum transfer capability is 546 megawatts. *Exhibit No. ___T (GND-1T) at 5, lines 17-22*.

Q. Does PacifiCorp's description provide an accurate understanding of the nature of the Company's transfer capabilities between control areas?

A. No. The numbers offered by PacifiCorp do not tell the whole story.

Q. Please explain the proper context for understanding the maximum transfer capability figures provided by Mr. Duvall.

A. Exhibit No. ___ (GND-2) shows 350 megawatts of East to West transfer capability on the transmission path from "Wyoming" to "Jim Bridger." However, that 350 megawatts is labeled "LLH," which means 350 megawatts is available only during "low load hours." Consequently, there are only 174 megawatts available during other periods (104 MW from East Main to Jim Bridger plus 70 MW from Amps Colstrip to West Main). This is a significant reduction from the total 546 megawatts claimed by Mr. Duvall.

The exhibit also shows that the Jim Bridger generating plant is a dedicated "Westside" resource. The Jim Bridger generating plant is a base load resource. The "Jim Bridger" to "West Main" transmission path is essentially devoted to transferring the electricity generated each day by the Jim Bridger generating plant to the Western Control Area. Accordingly, when Jim Bridger is generating near its capacity, that path is fully utilized, and as a consequence, that path is not available for transferring power East to West when Jim Bridger is functioning normally.

For East to West transfer capability, that leaves only the 70 megawatts from "Amps Colstrip" to "West Main." Mr. Duvall also identifies 100 megawatts of spinning reserve capacity and 100 megawatts of non-spinning reserve capacity on the system. However, those amounts are reserved for West to East transfers, not East to West transfers.

Q. Can the Company use the "Jim Bridger" to "IPC transmission" to "West Main" transmission path to transfer power from East to West when Jim Bridger is experiencing an outage?

A. Yes. However, that does not represent East to West transfer capacity the Company can count on and plan for. As PacifiCorp admits in its 2004 IRP: "Any additional generation to bring new resources into the PacifiCorp system from Idaho will require expansion of the transmission system." *PacifiCorp's 2004 Integrated Resource Plan, Exhibit No. ___ (APB-5) at 99.*

Q. How does PacifiCorp's West to East transfer capability compare to the limited East to West transfer capability you just described?

A. It appears that the Company's West to East transfer capability is less constrained than East to West. According to Mr. Duvall, PacifiCorp has 1,171 megawatts of West to East transfer capability. *Exhibit No. ___T (GND-1T) at 5, lines 21-22.* However, as shown on his Exhibit No. ___ (GND-2), 400 megawatts (281 winter megawatts) of that capacity is from Jim Bridger to Wyoming, and 441 megawatts is "day ahead" firm transmission. This is not the kind of capability that would support long-term delivery of an acquired resource. Furthermore, as I explain later, according the Company's IRPs, the Company's transfer capability from Idaho into "East Main" (called the Utah "bubble") is constrained.

3. The way PacifiCorp operates its Control Areas does not support the "Rolled-In" Revised Protocol Method for allocating resources

Q. Do the transmission constraints you just described justify the Revised Protocol's "rolled-in" allocation methodology for allocating resources?

A. No. As I just explained, there are significant constraints on the Company's ability to transfer power between its control areas. The Revised Protocol's underlying assumption is that most of PacifiCorp's resources are available to serve customers in all states. That assumption is defeated because PacifiCorp has significant transmission constraints that prevent it from operating its system that way, even though PacifiCorp does dispatch its resources from a single, central physical location.

Q. What is your response to Mr. Duvall's testimony that the Company dispatches its system to minimize its total costs, and it dispatches from a central location?

A. That testimony misses the point. As I testified earlier, the presence of an interconnected system, by itself, does not justify a system-wide, "rolled-in" cost allocation methodology. The transmission constraints of the Company are "real world." They affect the Company from a resource planning basis and the actual RFP, bidding, and acquisition process, which are all "real world" activities carried out by the Company.

Simply put, the fact that the Company's system is integrated to some degree and operated from a single location, is not sufficient support for the system-wide, "rolled-in" cost allocation methodology of the Revised Protocol.

What is important is whether resources in the Eastern Control Area can be used to serve Washington loads on a firm basis. If so, Washington ratepayers should share in the cost of those resources, if they are needed. If not, Washington ratepayers should not share in the cost of those resources. The facts show those Eastern Control Area resources have limited ability to serve Washington loads on a firm basis due to significant transmission constraints.

Q. How do you respond to Mr. Duvall's general 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 if that is the least-cost, least-risk option for the total system and for PacifiCorp's Washington customers." ***Exhibit No. ___T (GND-1T) at 7*****?**

A. Mr. Duvall's statement is misleading. As I explain in detail later, the Company has just completed acquiring, or is in the process of acquiring, over 1,400 megawatts of resources with a total cost of over $800 million, specifically because it could NOT move power from the West to the East.

Indeed, if Mr. Duvall's testimony is correct, PacifiCorp needs to demonstrate that these new resources it has acquired can serve Washington, and on a least cost basis, before the costs of those resources are allocated to Washington. The Company offers no such demonstration in its testimony or exhibits.

Q. What is the key issue regarding the nature of the interconnections between PacifiCorp's Western and Eastern Control Areas?

A. Again, the key issue is not *whether* there are any interconnections between the Western and Eastern Control Areas, but rather the *degree* to which PacifiCorp can actually transfer power between those control areas.

If the Company had no significant transmission constraints between its Eastern and Western Control Areas, that might support a system-wide, or "rolled-in" allocation method such as the Revised Protocol. However, at the present time, meaningful transfer capabilities are significantly less than what the Company identifies as "maximum" capabilities, particularly East to West. The level of system integration PacifiCorp enjoys by these limited transfer capabilities simply does not support the system-wide, "rolled-in" Revised Protocol's treatment of either PacifiCorp's new or previously-acquired resources.

Q. Has the Company estimated the amount and direction of net transfers between the Eastern and Western Control Areas?

A. Yes. Exhibit No. ___ (APB-6) contains the cover sheet from the Company's Response to Public Counsel Data Request No. 96. Public Counsel asked the Company to provide any studies that could be used to estimate the amount, direction, and/or timing of net power flows between PacifiCorp's Eastern and Western Control Areas when the Company's recently-acquired resources and purchase power contracts are operating.

In any event, the Company also responded by providing the generated hourly transfers between control area for the test period from its GRID model. The data over the 8760 hours of the test year shows modeled transfers from East to West and from West to East. The overall result is a net transfer, *West to East*, equal to an annual average of only around 175 megawatts.

Q. Is that response surprising?

A. No. It appears consistent with the constraints on PacifiCorp's transfer capacity between control areas I discussed earlier. The data also does not, in Staff view, support the system-wide, "rolling-in" treatment for resource costs, particularly new Eastside resources, that is the fundamental premise of the Revised Protocol.

Q. Does this mean that any benefits that are derived from actual transfers between control areas should not be recognized?

A. No. Although the Company's transfer capability between control areas does not support the system-wide, "rolled-in" treatment of resource costs under the Company's proposed Revised Protocol, there are other ways to capture any benefits and costs of transfers between the Western and Eastern Control Areas that may exist, enabling the Company to operate its system as it does now.

Q. Has the Company identified any operational benefits to Washington from the Company's two control areas?

A. Only in general terms. For example, Mr. Duvall claims that Washington customers benefit in numerous ways from both East and West resources. He discusses the benefits of "peak diversity" at a very general level, and claims that under-utilized resources in one control area can be used to serve customers in the other control area, to make additional wholesale sales, or to displace higher cost generation. Mr. Duvall claims that this "peak diversity" has allowed the Company to defer resource acquisitions that otherwise might have been acquired. He then goes on to say that the Company's integrated system allows Eastern Control Area resources to serve the Western Control Area during poor hydro conditions and forced or planned outages. *Exhibit No. ___T (GND-1T) at 39.*

Q. Does Staff agree with these Company representations?

A. No. Again, Mr. Duvall's testimony ignores the real, limited nature of the interconnections between the two control areas. As I explained earlier, the issue is not whether *some* benefits exist based on PacifiCorp's limited power transfer capabilities between control areas. The issue is whether *the extent of these benefits* warrants the Revised Protocol's system-wide, "rolled-in" approach to cost allocations, versus some other method of recognizing whatever benefits of interconnection may exist.

It continues to trouble Staff that PacifiCorp continues to support the Revised Protocol through broad statements such as those of Mr. Duvall. Put another way: If the benefits he describes truly exist, why has the Company failed to provide a demonstration of such benefits in any forum where the Company has evaluated its needs to acquire significant new resources?

Note also that Mr. Duval's claims are carefully conditioned by phrases like: "as long as these Eastern Resources are not being fully utilized." This is a significant qualification, because the Company is rapidly acquiring resources to serve the Eastern side of its system, at a time when few or no resources are needed in the West.

Q. Has the Company claimed any operational benefits to Washington or the Western Control Area from its more recent acquisitions of the Gadsby, West Valley, and Currant Creek projects?

A. Yes. Mr. Duvall provides examples of how these resources could provide operational benefits to the Western Control Area. *Exhibit No. ___T (GND-1T) at 43.* However, these benefits for the most part require transfer capability between control areas, or the ability to displace Western Control Area resources that were previously claimed as being used for Eastern loads. The Company has provided no quantification of the so-called "displaced resource" benefits from these significant new resources.

Moreover, as I explain later, PacifiCorp acquired these resources to meet increased load growth in Utah, not to "free up" resources to meet the needs of the Western Control Area use. Indeed, the Western Control Area's resource needs are minimal in the near term, while the Eastern Control Area's needs remain, significant.

Even assuming a Western resource need and that the Company's claims of displacement benefits were valid, the Company has provided no demonstration that the acquisition of an East side resource and subsequent system-wide, "rolled-in" allocation of those costs was the least cost for serving Washington's needs.

Q. Has the Company provided any additional evidence that the energy from these recently acquired resources is used by customers in Washington?

A. No. The Company has provided only very broad and nebulous responses to questions requesting such evidence. Exhibit No. ___ (APB-7) contains the Company's Responses to ICNU Data Request Nos. 7.5(i) and 7.6. Those requests asked the Company to provide evidence that power generated at the Currant Creek, Gadsby Peakers, and West Valley units is actually used by customers in Washington.

The Company's response was simply that power generated by these plants:

> …is used by retail customers in Washington in the sense that all generation on-line at a particular time supports all loads throughout the Western Interconnection. This has been evidenced many times during events of any generation outage temporarily causing decreases in system frequency throughout the Western Interconnection …

Q. Is the Company's response helpful?

A. No. These data requests presented the Company another clear opportunity to provide a specific, credible demonstration that the Company's actual system operations supported the Revised Protocol's system-wide, "rolling-in" of costs. Instead, the Company provided only over-broad statements that avoid addressing the real issues. Indeed, as I mentioned earlier, the entire

Western United States is electrically "interconnected" through control areas. The Company's responses to ICNU could justify the costs associated with hundreds of generating plants across the entire Western Interconnection being allocated to Washington.

D. The Revised Protocol Method Compared to How PacifiCorp Plans its System Acquisitions

Q. Does the manner in which PacifiCorp plans for system acquisitions affect the Commission's analysis of the appropriate cost allocation method?

A. Yes. As I mentioned earlier, the Revised Protocol results in costs associated with Eastern Control Area resources being allocated to Washington and the other states in the Western Control Area. This approach might have some merit if, during the Company's planning process for these Eastern Control Area resources, PacifiCorp identified and quantified the benefits these resources provided to Washington and other states in the West, as well as the costs.

However, as I explain below, PacifiCorp did not identify such benefits in its resource planning process that led the Company to acquire these resources. In short, the Company's "rolled-in" Revised Protocol method is not supported by the Company's planning documents.

Q. How is this section of your testimony organized?

A. First, I explain the IRP and RFP processes the Company engages in when it acquires new resources. Second, I describe how the Company's planning documents supporting its acquisition of Eastern Control Area resources did not consider benefits of these resources to the Western Control Area, in general, or Washington in particular. Finally, I explain how the manner in which PacifiCorp actually plans its resource acquisitions does not support the Revised Protocol methodology.

1. The IRP/RFP processes, and how they are relevant to the cost allocation issue

Q. Please explain the acronyms "IRP" and "RFP."

A. "IRP" stands for "Integrated Resource Plan," and it is sometimes called a "least cost plan." "RFP" stands for "Request for Proposals," and it represents the initial stage in the Company's acquisition of new resources.

Integrated Resource Plans, or IRPs, are a key part of the process used by utilities such as PacifiCorp when they are acquiring new resources. IRPs are required by the rules of most commissions. For example, under WAC 480-100-238, the Commission requires electric utilities to file a "least cost plan," in which the utility forecasts the future demand for electricity for its system, and analyzes the least cost mix of resources that will meet the current and future needs of the utility and its customers.

An RFP is the document in which the utility solicits bids for new resources. As such, it is a key part of a competitive bidding process by which utilities such as PacifiCorp acquire new resources. This process is also required by the rules of most commissions. For example, under Chapter 480-107 WAC the Commission prescribes how an electric utility is to solicit, evaluate and act on bids by suppliers of new electric resources.

Q. Has PacifiCorp filed IRPs and RFPs in this state in the past?

A. Yes. I will describe many of these filings in this section of my testimony.

Q. How are PacifiCorp's IRPs and RFPs relevant to the cost allocation issues in this case?

A. These documents provide the critical evidence necessary to determine cost causation, *i.e.,* they provide the reasons why the Company is adding a resource, and how that resource was acquired. PacifiCorp's IRPs and the RFPs, including the Company's evaluations of the bidding pursuant to an RFP, are examples of where "the rubber meets the road." These processes are real processes, undertaken by the Company. They show how the Company views its system, and why it is acquiring resources.

As I explain later, the Company's own IRP, RFPs, and bid evaluations do not support the Company's claims of a jointly planned and operated system that might support the Revised Protocol.

2. *The conflict between the Revised Protocol and the IRPs filed by PacifiCorp*

Q. Is there consistency between the Revised Protocol and the Company's actions during the IRP process?

A. No.

Q. Please describe the nature of this inconsistency.

A. The Revised Protocol's "rolling-in" methodology allocates to all states the costs of the resources the Company acquired to serve the Eastern Control Area. This is inconsistent with the Company's recognition in its IRPs that the Company operates in two separate control areas that have significantly different resource needs.

In other words, how PacifiCorp plans to add costs (*i.e.*, resources) to its system is inconsistent with the manner in which the Company's Revised

Protocol allocates those same costs. Recently, the Company's planning process clearly shows that the demands of the Eastern Control Area caused the Company to acquire significant new resources whose costs are now being allocated to Washington under the Revised Protocol. This is clear confirmation that the Revised Protocol violates cost causation principles.

Q. Can you provide an example of a PacifiCorp IRP in which the Company has recognized the significantly different characteristics of its two control areas?

A. Yes. One example is PacifiCorp's 2003 IRP. I provide an excerpt of that IRP in my Exhibit No. ___ (APB-8). On page 33 of its 2003 IRP, the Company states: "These two control areas have very different resource and transmission issues, which results in a different balance in loads and resources for each side of the system."

PacifiCorp goes on to consider the different characteristics of the two control areas throughout the 2003 IRP, including the Company's identification of separate, specific Westside and Eastside resource needs in the final Action Plan on page 153. The reality of two different control areas is particularly evident in the Company's discussion of the different transmission characteristics of the West and East.

Q. Did PacifiCorp update its 2003 IRP?

A. Yes. On October 29, 2003, the Company filed an update to its 2003 IRP, and incorporated several changes. An excerpt from the Company's 2003 Update is in my Exhibit No. ___ (APB-9).

Q. Despite the changes the Company made to its 2003 IRP, did the Company continue to recognize the different needs of its two control areas?

A. Yes. In the Executive Summary on page 1 of the 2003 Update, the Company states: "PacifiCorp has also conducted further detailed model validation against actual system operations data and has improved the synchronization of short-term operations and planning with long-term planning efforts." *Exhibit No. ___ (APB-9) at page 1, 4th ¶.*

Essentially, the updated information caused the Company to revise its load-resource balance estimates, and gave the Company an enhanced way of representing this balance by location. For example, in the Executive Summary of the 2003 IRP Update, PacifiCorp goes on to say that: "In light of this new information, PacifiCorp is able to conclude that resource requirements in the Eastern control area are accelerated and in the Western control area are somewhat delayed," as compared to earlier least cost, least risk portfolios. *Id., last ¶.*

In addition, PacifiCorp states that its "ongoing request for proposal (RFP) process is expected to provide additional information regarding resource availability, costs, and timelines to help fill the accelerated Eastern control area short position." *Id.*

Each of these statements confirms that the Company treats the needs of its two control areas separately.

Q. What is appropriate to conclude from these statements by PacifiCorp in the 2003 IRP Update?

A. The Company clearly plans for its two control areas separately. The Company does not plan its system as an integrated whole. A "rolled-in" allocation method like the Revised Protocol is not justified under these circumstances.

Q. Are there any more specific changes to the planning process that were outlined in PacifiCorp's 2003 Update to its 2003 IRP that confirm those conclusions?

A. Yes. In its 2003 Update, PacifiCorp made relevant changes to its 2003 IRP in three areas – load forecasts, model topology, and how short positions were to be evaluated. Each of these changes reflects substantial differences between the Company's two control areas.

Q. What changes did PacifiCorp make to its load forecasts in its 2003 Update to its 2003 IRP?

A. PacifiCorp's updated long-term growth rates reflected the latest forecasts by the Company. According to the Company: "There has been a shift in the forecast such as 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)." *Exhibit No. ___ (APB-9) at page 4, 5th ¶.*

Indeed, the Company's forecasted total load growth rate for Washington declined from 2 percent to 1.8 percent, while the total load growth rate for Utah increased from 3 percent to 3.5 percent. PacifiCorp's forecasted summer peak demand for Washington increased from 1.8 percent to 3 percent, while Utah's summer peak demand forecast changed almost two-fold: from 2.7 percent to 5.1 percent. *Id. at pages 4 & 5, Tables 2.1 & 2.2.* PacifiCorp explained that Washington's lower sales growth was due to an assumed slower population growth. PacifiCorp explained that Washington's increase in peak growth was the result of increased household size and air conditioner load. *Id. at 6, 6th ¶.*

Q. What is significant about the model topology changes PacifiCorp made in its 2003 Update?

A. PacifiCorp modified its IRP model topology in part to "better represent transmission constraints and the access to markets available on the system." *Exhibit No. ___ (APB-9) at page 9, last ¶ to page 10.* PacifiCorp's "Updated IRP Topology" shown in Figure 2.1 on page 10 clearly shows that the Eastern and Western Control Areas have separate load centers and there is limited transmission capability between them.

Q. What changes did PacifiCorp make to its evaluation of short positions in the 2003 Update?

A. PacifiCorp's 2003 Update changed the method by which PacifiCorp evaluates its load/resource balance positions.

The 2003 Update breaks the Company's system into two "tiers," based on transmission constraints. According to page 12 of the 2003 Update: "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)." *Exhibit No. ___ (APB-9) at page 12, 4th ¶.*

For planning purposes, PacifiCorp defines a Tier 1 position as having the risk of insufficient resource capacity within a transmission constrained area. PacifiCorp includes the Utah Bubble (loads, resources, contracts in Southeast Idaho, Utah, and Southwest Wyoming) in Tier 1. *Id., 5th and 6th ¶¶.*

PacifiCorp defines a Tier 2 position as when the Company has insufficient resources in an unconstrained area. PacifiCorp includes the Western Control Area as Tier 2. *Id. at page 14, 3rd ¶.*

Q. How do these changes to load forecasts, IRP model topology, and evaluation of load/resource balance positions affect the analysis of what is a proper inter-jurisdictional cost allocation method?

A. These changes further document the differences between PacifiCorp's two control areas that PacifiCorp plans separately for them. For example, the Company's updated forecasts prove that load growth in PacifiCorp's system is not uniform: Utah is the primary contributor to the need for PacifiCorp to acquire new resources.

The Company's updated model topology adds further proof that there is limited firm transfer capability between the Company's two control areas.

Finally, PacifiCorp's updated analysis in which the Company evaluates its load and resource balance positions on a "Tier 1 and Tier 2" basis also confirms the significant differences in control areas. As PacifiCorp concludes:

> Planning efforts for Tier 1 risks are best managed by 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. 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.

2003 Update, Exhibit No. ___ (APB-9), at page 14, 2nd ¶ (emphasis added).

PacifiCorp's planning for "targeted, geographically specific physical solutions" confirms that a "rolled-in" approach to allocating resource costs is not appropriate for PacifiCorp.

Q. Are there other statements by PacifiCorp in the 2003 IRP Update that show why a system-wide, "rolled-in" cost allocation methodology is not appropriate for Washington?

A. Yes. PacifiCorp goes on to state at page 15 of the 2003 Update:

> The FY2005 position 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 the 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. However, the high level of transfers is limited to select hours.

Id. at 15, 4th ¶. Here, PacifiCorp is making the straightforward statement that the Western Control Area, which includes Washington, is "resource sufficient," and even has resources sufficient to "maximize transfers" of power to the Eastern Control Area, though only during "select hours," due to transmission constraints.

These statements by PacifiCorp are inconsistent with a cost allocation methodology such as the Revised Protocol, that allocates the costs of Eastern Control Area resources on a system-wide, "rolled-in" basis to states located in the Western Control Area, such as Washington.

In fact, these statements by PacifiCorp should have been sufficient for the Company to have abandoned the Revised Protocol at that time.

Q. Did PacifiCorp file any other updates to its 2003 IRP?

A. Yes. In October 2004, the Company filed a 2004 Update in which it again adjusted several of its assumptions from the 2003 Update, including load growth forecasts. I include an excerpt from the 2004 Update in my Exhibit No. ___ (APB-10).

Q. What did the Company's 2004 Update show?

A. The Company's forecast of Washington's total energy growth decreased slightly, from 2 percent to 1.7 percent, as did the forecast of total energy growth for Utah: from 3.9 percent to 3.7 percent. *Exhibit No. ___ (APB-10) at 5 (comparing figures in "Mar-03" and "Feb-04" columns).*

The Company's summer coincident peak growth forecast decreased slightly, although the growth rate of Utah remained well above that of the other states, *e.g.*, 4.5 percent for Utah, compared to 2.3 percent for Washington. *Id. at 6.*

The bottom line of PacifiCorp's 2004 Update is reflected in the Company's renewed conclusion that the Western Control Area was capacity sufficient until 2012, and energy deficient only in the off-peak period, until the expiration of a BPA Exchange contract. At the same time, the Company concluded that the Eastern Control Area would be capacity deficient beginning in 2006, and energy deficient off-peak for 10 years, with no additions and on-peak starting the summer of 2008. *Id. at 20.*

Q. What conclusions are appropriate to draw from these conclusions by PacifiCorp in the 2004 Update?

A. PacifiCorp operates in two control areas with substantially different prospective resource requirements. This does not support the system-wide, "rolled-in" approach for allocating resource costs.

This is particularly true when the resource needs of the two control areas are so different. In other words, customers located in a control area that is capacity sufficient (Western Control Area) should not pay for any additional capacity, let alone additional capacity PacifiCorp needs to serve customers in another control area (Eastern Control Area).

In this situation, the Company could best serve the Western Control Area by simply purchasing off-peak energy when and if it is needed. The Company can best meet the needs of the Eastern Control Area by acquiring much more expensive capacity and energy resources.

The bottom line is that the Revised Protocol is not appropriate because it results in the allocation to Washington and the Western Control Area a portion of the cost of new resources the Company is acquiring to serve the Eastern Control Area.

Q. Did the Company file a 2004 Integrated Resource Plan?

A. Yes. In January 2005, the Company filed its 2004 IRP. The Commission assigned the matter Docket No. UE-050095. This is the latest IRP PacifiCorp has filed in this state. I include excerpts from PacifiCorp's 2004 IRP in my Exhibit No. ___ (APB-5).

Q. In its 2004 IRP, does PacifiCorp continue to show higher growth in the Eastern Control Area compared to Washington and the Western Control Area?

A. Yes. PacifiCorp forecasts an average annual peak load growth rate of 3.8 percent in the Eastern Control Area, over two and one-half times the 1.5 percent growth rate in the Western Control Area. *Exhibit No. ___ (APB-5) at page 44, 3rd ¶.* The Company's 2004 IRP also contains some interesting historical and forecast load information.

Q. What does PacifiCorp's 2004 IRP show for historical and forecasted load growth in Washington compared to Utah?

A. From 1991 through 2003, Utah's average annual growth rate for load was two and one-half times the rate in Washington: 3.5 percent for Utah versus 1.4 percent for Washington. *Id., Table 3.1, 1991-2003 forecast.* PacifiCorp now forecasts Utah's average load to grow at an annual rate three and one-half times that of Washington: 3.5 percent for Utah compared to 1.0 percent for Washington. *Id., Table 3.1, 2006-2015 forecast.*

Peak load growth is even more divergent between the two states. From 1991-2003, Washington's annual peak load growth rate was just under 0.5 percent (.47 percent), while Utah's was 6.22 percent. PacifiCorp forecasts a peak load growth for Washington of 1.8 percent, while Utah peak load growth is forecast to be 4.58 percent. *Id., Table 3.2, 2006-2015 forecast.*

Q. What is the significance to this case of these disparate load growth data from PacifiCorp's 2004 IRP, comparing Washington to Utah and the Eastern Control Area to the Western Control Area?

A. First, this data is further confirmation that the Western Control Area and the Eastern Control Area present very different demands for new resources, both in type of resource and quantity of resources. Load growth is high in the Eastern Control Area, particularly in Utah, and this creates a higher demand for new resources than in the Western Control Area, and particularly in Washington. These divergent ranges of growth do not support the system-wide, "rolled-in" allocation method that is featured in the Revised Protocol.

Second, this data shows again how the Company clearly takes into consideration in its planning process the different load growth rates of the two control areas of its system.

Finally, as I discussed earlier, the resources that meet the needs of the Eastern Control Area are not the same as the resources needed for the Western Control Area. Even if PacifiCorp enjoyed no transmission constraints between the East and West, Washington, for example, should still not be allocated a portion of the capacity costs of the Company's new Eastern Control Area resources, because Washington did not cause the Company to acquire that new capacity, and the Company has identified no benefits to Washington from that capacity.

Q. Did PacifiCorp also change its modeling topology in its 2004 IRP?

A. Yes. PacifiCorp's latest System Topology is shown and discussed on pages 54 and 55 of the 2004 IRP, in my Exhibit No. ___ (APB-5). This again confirms the limited transfer capability between the Eastern and Western Control Areas. For example, PacifiCorp shows the transmission path from "Borah" in the Western Control Area to the Eastern Control Area to be in one direction only: from West to East. In other words, the states in the Western

Control Area, such as Washington, cannot receive power from the Eastern Control Area via this transmission path.

Note also the "Jim Bridger" to "Borah" path is primarily dedicated to the transfer of the Jim Bridger plant energy into the Western Control Area.

Q. What load and resource balance positions does PacifiCorp show in its 2004 IRP?

The Company analyzes load-resource balance for the Western Control Area separately from the Eastern Control Area. For example, The Company explains future changes in Western Control Area positions by assuming losses of Western resources, namely the TransAlta Contract and the BPA Peaking Contract. *Exhibit No. ___ (APB-5) at 56 and 57.* The Company explains changes in Eastern Control Area positions by identifying the additions of resources located in the Eastern Control Area (Lake Side and West Valley Lease). *Id. at page 58.*

Q. What is the significance of these data for this case?

A. This refutes PacifiCorp's claim that it PacifiCorp plans on a system-wide basis. There is a real difference between the Eastern Control Area and the Western Control Area, as demonstrated by different load growth forecasts, load and resource balance positions. Ultimately, the resource needs of the two control areas are very different. Consequently, a system-wide, "rolled-in" allocation method such as the Revised Protocol is not justified in these circumstances.

3. *PacifiCorp's Requests for Proposals and the Competitive Bidding Process for New Resource Acquisitions*

Q. Please describe the competitive bidding process by which PacifiCorp acquires new resources.

A. Like the IRP process, the RFP competitive bidding process is particularly important when a utility is acquiring a large amount of resources. The Company follows a three step process: 1) the Company issues the Request for Proposals, or RFP; 2) the Company evaluates the bids; and 3) the Company acquires appropriate resources, if any are offered.

Like the IRPs, each of these stages reflects a true "rubber-meets-the-road" test of what the Company's resource needs are, and how the Company evaluates and meets those resources needs.

Q. Has PacifiCorp acquired a large amount of resources in the past few years?

A. Yes. Since 2000, PacifiCorp has acquired almost 1400 megaWatts of new generating facilities, and it has entered into significant new QF and other purchase power agreements almost entirely in the Eastside of the Company's system.

Q. Did the Company file an RFP in Washington during that period?

A. Except for a targeted renewable resource solicitation, no. However, on August 14, 2003, after discussions with Staff, the Company filed avoided cost data and a statement that it did not intend to issue a Commission approved RFP in Washington. On September 25, 2003, the Company filed a draft RFP, which included the following language:

> Consistent with PacifiCorp's January 2003 Integrated Resource Plan, PacifiCorp has identified a resource block of zero megawatts for this Request for Proposals ("RFP"). Although PacifiCorp is currently seeking to acquire certain types of resources through specifically-tailored solicitations, it does not propose to issue a Commission-approved RFP in Washington as a means of securing additional resources.

Q. What happened to that filing?

A. The Commission issued an order suspending that filing. The Commission assigned the matter Docket No. UE-031311. On January 2, 2004, PacifiCorp filed a Request for Waiver of the RFP filing requirement. A settlement was reached by the parties and approved by the Commission, which resolved all issues, including the waiver request.

Under the settlement, the Company revised the draft RFP language to clarify that it was the RFP's intent to support the Commission's ongoing assessment of the cost and availability of resources to PacifiCorp. In addition, the Company agreed to file with the Commission copies of each RFP issued by the Company in other states, plus a document summarizing the process and results of those RFPs.

Q. Why are these Company actions relevant to the allocation methodology issues in this case?

A. As I described earlier, PacifiCorp's proposed Revised Protocol allocates to Washington a portion of all the resources recently acquired by the Company. Yet the Company has not made a single demonstration that these resources were needed in Washington, or were capable of providing benefits to Washington. At the same time, the Company was reluctant to provide an RFP process in Washington that would be a tool for the Company to evaluate and compare least cost resource options for serving the state.

The Company's segregated approach to resource acquisitions, further evidences by its reluctance to file RFPs in this state, clearly support Staff's position that the resources PacifiCorp has been acquiring are not truly system-wide resources. Therefore, a system-wide, "rolled-in" cost allocation methodology such as the Revised Protocol is inappropriate for determining Washington rates.

Q. Has PacifiCorp filed copies of its most recent draft RFP in compliance with the settlement in Docket No. UE-031311?

A. Yes. In June 2005, the Company filed the draft of its 2009 RFP. This RFP calls for up to 525 MW of supply side resources to be delivered within the Eastern Control Area by the summer of 2009. However, it appears that the Company's new load and resource forecasts, and other changes in assumptions have eliminated the need for the 2009 RFP, and it has been delayed by the Company.

Q. How is this 2009 IRP filing relevant to allocation methodologies?

A. The Company's actual filing of a draft RFP for Eastern Control Area resources in Washington is a good step in following the acquisition process. However, it confirms Staff's position that the Company's substantial need for resources is in the Eastern Control Area. The Company does not "jointly" plan for its system as a whole. Accordingly, a system-wide, "rolled-in "cost allocation methodology for resources such as the Revised Protocol is not appropriate.

Q. In this case, what documents did you review regarding the competitive bidding process for resources recently acquired by the Company and included for recovery in this proceeding?

A. I reviewed the direct testimony of PacifiCorp witness Mr. Tallman, in which he discusses the Company's recent acquisition of projects including the West Valley Lease, and the Gadsby and Currant Creek projects. *Exhibit No. ___T (MRT-1T) at 2-24*. I also reviewed his exhibits, which contain various PacifiCorp RFPs and bid evaluations. *Exhibit Nos. ___ (MRT-2) - ___ (MRT-13C).*

I also reviewed PacifiCorp's most recent resource acquisition activities under the competitive bidding, or RFP process. In addition, I reviewed the most recent actions of the Company in regard to overall resource acquisition policy here at the Commission.

Q. How are these Company competitive bidding documents relevant to the cost allocation issues in this case?

A. These were documents under which PacifiCorp acquired significant new resources. Under the Revised Protocol, the cost of these new resources are "rolled-in" on a system-wide basis and allocated to all jurisdictions, including Washington.

Consequently, this was another opportunity for PacifiCorp to document whether the resource needs of Washington or the Western Control Area were causing the Company to acquire these new resources. If so, that could support a "rolled-in" method of allocation, such as the Revised Protocol.

Q. Do the Company's RFPs support the concept of a system-wide, "rolled-in" allocation of new resource costs such as PacifiCorp is proposing under the Revised Protocol?

A. No. The RFPs and the testimony of Mr. Tallman support just the opposite. In addition, the reluctance of the Company to even file an RFP in Washington, as required under the Commission's least cost planning rules, means that the "rolling-in" of costs would be carried out without a demonstration by the Company that these new Eastern Control Area resources are cost effective for Washington, based on a detailed evaluation of available alternatives via a Westside solicitation.

Even if there were no transmission constraints, Washington should not "automatically" pick up costs of Eastern Control Area resources in which no Western Control Area alternatives have been analyzed. However, this conclusion becomes even more compelling because transmission constraints make it uncertain whether PacifiCorp can even deliver power from these new resources to the Western Control Area.

a. The West Valley Lease

Q. What is the West Valley Lease?

A. The West Valley Lease is a lease under which PacifiCorp acquired the output of a 200 MW gas-fired turbine generating station. The lease is for a period of 15 years, ending December 31, 2017. The generating station is located in West Valley, Utah, near Salt Lake City.

Q. Is the Company, through the Revised Protocol, requesting recovery of the costs associated with the West Valley Lease in this proceeding?

A. Yes. Under the Revised Protocol, the West Valley Lease costs are "rolled-in" on a system-wide basis and a portion of the costs of that project are allocated to Washington. Specifically, the Revised Protocol allocates approximately $1.4 million of the total $16.5 million annual lease costs of the project to

Washington rate base, and approximately 8.3 percent of the project's total annual operating and fuel expenses.

Q. Did PacifiCorp acquire the West Valley Lease through the RFP process?

A. Yes. PacifiCorp acquired the West Valley Lease under its 2001 RFP. PacifiCorp's 2001 RFP is Mr. Tallman's Exhibit No. ___ (MRT-3).

Q. Please describe some relevant features of PacifiCorp's 2001 RFP that resulted in the West Valley Lease acquisition.

A. In the 2001 RFP, PacifiCorp was seeking to acquire power that could be delivered to the Company's Eastern Control Area. *Exhibit No. ___ (MRT-3) at 4.* The RFP specifically excluded resources delivered to Borah, Brady, or Kinport, unless the power was physically located in, or capable of delivery directly to, the Company's Southeast Idaho electrical system (at a voltage below 230kv), which is also located in PacifiCorp's Eastern Control Area. *Exhibit No. ___ (MRT-3) at 5.*

Q. Please explain the 2001 RFP process, and how PacifiCorp used that process to acquire the West Valley Lease.

A. The process is described by PacifiCorp in Mr. Tallman's direct testimony, Exhibit No. ___T (MRT-1T). At page 3, lines 8-13, Mr. Tallman confirms that the West Valley lease was acquired to address a continued imbalance in the Company's Eastern Control Area between summer peak load requirements and the resources to meet that load. He concludes that PacifiCorp needed a resource "to allow it to meet seasonal East-side peak demand."

At pages 3-6 of his testimony, Mr. Tallman goes on to describe PacifiCorp's process for acquiring the lease, and on page 3, lines 19-20, he reiterates: "The Company's goal was to secure cost effective resources to meet its East-side capacity requirements."

In other words, Washington and the Western Control Area were not causing the Company acquire the West Valley Lease.

Q. Does PacifiCorp claim any benefits to Washington or the Western Control Area from the West Valley Lease?

A. No. In his testimony at pages 7-9, Mr. Tallman discusses the many benefits of the lease to the Eastern Control Area. He also uses the term "system benefits," but that is limited to his claims of resource diversity, increased voltage support and reliability, and reducing the risks of market prices, each of which is oriented toward the Eastern Control Area.

Q. Did PacifiCorp's Board of Directors approve the West Valley Lease acquisition?

A. Yes. The Board Meeting notes are Mr. Tallman's Exhibit No. ___ (MRT-6C). The Company's Board of Directors approved the lease in March 2002.

Q. Is there anything in the Board Meeting notes that indicate the Board considered any benefits of the West Valley Lease to Washington or the Western Control Area?

A. No.

Q. Has PacifiCorp taken any further evaluation of the West Valley Lease subsequent to the Board's approval in March 2002?

A. Yes. Subsequent to entering into the West Valley Lease, the Company has considered the possibility of terminating that lease. PacifiCorp issued another RFP with a goal to replace the West Valley Lease power. However, to date, the West Valley Lease remains a resource of PacifiCorp.

Q. Did that subsequent RFP PacifiCorp issued contain any discussion or analysis of possible benefits to Washington or the Western Control Area?

A. No.

Q. Did PacifiCorp file with the Commission the RFPs that resulted in the acquisition of the West Valley Lease, and then the possible termination of that lease?

A. No.

Q. Has PacifiCorp provided any evidence that the power from the West Valley Lease can be delivered into the Western Control Area?

A. No.

b. The Gadsby Peaker Project

Q. What is the Gadsby Peaker Project?

A. The Gadsby Peaker Project is comprised of three 40 MW gas turbine generators. The Gadsby Peaker Project is located in Salt Lake City, Utah.

Q. Is the Company, through the Revised Protocol, requesting recovery of the costs associated with the Gadsby Peaker Project in this proceeding?

A. Yes. Under the Revised Protocol, the Gadsby Peaker Project costs are "rolled-in" on a system-wide basis and a portion of the costs of that project are allocated to Washington. Specifically, the Revised Protocol allocates approximately $6 million of the total $75 million project to Washington rate base, and approximately 8.3 percent of the project's total annual operating and fuel expenses.

Q. Did PacifiCorp acquire the Gadsby Peaker Project through the RFP process?

A. No, although it is acceptable under Washington rules for a utility to acquire a resource outside the RFP process, so long as the Company makes a prudence showing. On pages 17-20 of his direct testimony, Mr. Tallman discusses how the costs of the Gadsby Peaker Project compared to those resources acquired through the 2001 RFP. He concludes that the project "compared very favorably with the resources acquired through the RFP." *Exhibit No. ___T (MRT-1T) at 17, lines 20-21.*

Q. Did Washington or the Western Control Area cause PacifiCorp to acquire the Gadsby Peaker Project?

A. No. As Mr. Tallman testifies, the project "represented a least-cost, new resource option that was consistent with the demand for summer peak capacity in PacifiCorp's East Control Area." *Exhibit No. ___T (MRT-1T) at 17, lines 11-13.*

The Gadsby Peaker Project provides for 120 MW of capacity utilizing simple-cycle, gas-fired turbines, which are typically used for peaking purposes. As the Company explains, the project also provides for short notice power capability in the Company's Eastern Control Area, when incremental generation costs are below market and during periods of load obligations when no remaining transmission import capability exists. *Exhibit No. ___T (MRT-1T) at 18, lines 12-16.*

Q. Did PacifiCorp's Board of Directors approve the acquisition of the Gadsby Peaker Project?

A. Yes. The Board Meeting notes are Mr. Tallman's Exhibit No. ___ (MRT-9C). The Company's Board of Directors approved the lease in October 2001.

Q. Is there anything in the Board Meeting notes that indicate the Board considered any specific benefits of the Gadsby Peaker Project to the Western Control Area?

A. No. As Mr. Tallman testifies, the Gadsby Peaker Project was presented to the Board as a flexible thermal resource for the Eastern Control Area. *Exhibit No. ___T (MRT-1T) at 20, lines 11-17.* [redacted]

[redacted]

Q. What conclusions are appropriate to draw from the evidence regarding why PacifiCorp acquired the Gadsby Peaker Project?

A The testimony and analysis presented by the Company in this proceeding, including the material that was presented to PacifiCorp's Board of Directors when the decision was made to acquire the project, clearly show that the Gadsby Peaker Project was not acquired to meet the needs of Washington or the Western Control Area, or to provide quantifiable benefits to the Westside sufficient to warrant the system-wide, "rolling-in" of related costs, as proposed by the Revised Protocol.

c. The Currant Creek Project

Q. What is the Currant Creek Project?

A. The Currant Creek Project is a $350 million project, consisting of two gas turbine generating units with a nominal capacity of 140 MW each. The two units are scheduled for completion in 2005. In early 2006, the units will be converted to a combined cycle combustion turbine, with a total capacity of 525 MW. The Currant Creek Project is located in Juab County, Utah, which is south and west of the City of Provo.

Q. Is the Company, through the Revised Protocol, requesting recovery of the costs associated with the Currant Creek Project in this proceeding?

A. Yes. Under the Revised Protocol, the Current Creek Project costs are "rolled-in" on a system-wide basis and a portion of the costs of that project are allocated to Washington. Specifically, the Revised Protocol allocates approximately $29.4 million of the total $347 million project to Washington rate base, and approximately 8.5 percent of the project's total annual operating and fuel expenses.

Q. Did PacifiCorp acquire the Currant Creek Project through the RFP process?

A. Yes. PacifiCorp acquired the Currant Creek Project under its 2003-A RFP, which is Mr. Tallman's Exhibit No. ___ (MRT-11).

Q. Please describe some relevant features of PacifiCorp's 2003-A RFP process that resulted in the Company acquiring the Currant Creek Project.

A. PacifiCorp's 2003-A RFP was similar to the other PacifiCorp RFPs I have discussed, in that the Company was not interested in receiving proposal for power delivered in the Western Control Area. This conclusion was summarized by PacifiCorp itself on page 3 of its 2003-A RFP, when the Company defined the scope of the RFP: "The scope of this solicitation … will be with respect to supply-side resources that are capable of delivery to PacifiCorp's network transmission system in PacifiCorp's East control area." *Exhibit No. ___ (MRT-11) at 3, 1st ¶.*

PacifiCorp did not change the scope of the RFP during the RFP process. I have reviewed the 2003-A RFP (Exhibit No. ___ (MRT-11), which includes PacifiCorp's bidding guidelines, and the independent consultant's report which evaluated the bids that were received in response to the RFP (Exhibit No. ___ (MRT-12). Nowhere did PacifiCorp consider the needs of Washington or the Western Control Area, or potential benefits to those areas. Likewise, there was no discussion or evaluation of the proposals regarding the ability of any project to serve the West.

Q. Did PacifiCorp identify any benefits of the Currant Creek Project to Washington or the Western Control Area in the materials provided to the Company's Board of Directors for decision on the project?

A. No. The materials presented to the Board are contained in Mr. Tallman's Exhibit No. ___ (MRT-13C). [redacted]

Q. Did PacifiCorp request construction authorization from the Utah Public Service Commission for the Currant Creek Project?

A. Yes. As I understand it, PacifiCorp needs to obtain a certificate of convenience and necessity for the Currant Creek Project from the Utah commission. The Utah commission assigned the matter Docket No. 04-035-30.

Q. Did you review the testimony the Company filed in support of its request in that docket?

A. Yes.

Q. What did you find?

A. As in the documents from the RFP process, PacifiCorp's Utah testimony focused exclusively on the benefits of the Currant Creek Project in meeting the needs of the Company's Eastern Control Area. In its testimony in that docket, the Company made no mention of specific benefits for the Western Control Area or for Washington. PacifiCorp made many, many references to the needs of Utah, especially along Utah's Wasatch Front. It is exclusively a part of the Company's Eastern Control Area.

Q. Please provide some examples from that Utah docket where PacifiCorp witnesses focused on the needs of the Eastern Control Area.

A. PacifiCorp witness Mr. Thurgood stated at page 9 of his prepared testimony in that docket: "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."

PacifiCorp witness Mr. Cassity, at page 4 of his prepared testimony, stated: "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. These 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."

Mr. Cassity also emphasized on page 8 of his Utah testimony:

> 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.

Q. Does your answer exhaust the examples from PacifiCorp's testimony in Utah Docket No. 04-035-30 where the Company defended the Currant Creek Project based on the need to serve Utah load?

A. No. I provided only a few of the many parts of PacifiCorp's Utah testimony in which the Company stated that the Currant Creek Project was critically needed to address the needs of the Eastern Control Area in general, and the Company's service area in Utah in particular. The Company also provided testimony in that docket describing the RFP and bid process, including the Company's recognition that Currant Creek was being acquired for the Eastern Control Area.

Q. In its Utah testimony, did the Company indicate that Currant Creek would meet the needs of Washington or the Western Control Area?

A. No. The Company provided no testimony addressing any needs of the West that could be met by Currant Creek. Nor did the Company mention any benefits to the Westside. Yet again, under the Revised Protocol being proposed by Company, the costs of this project are being allocated on a system-wide, "rolled-in" basis to all jurisdictions, including Washington. That is simply not appropriate.

Q. Did the Company file an RFP in Washington contemporaneously with the acquisition of the Currant Creek Project?

A. No. The Company did, however, file a request for waiver, so that it would not have to file an RFP in Washington for new resources. I discussed that waiver docket earlier.

d. The Lake Side Power Project and other Eastern Control Area power supply resources

Q. What is the Lake Side Power Project?

A. The Lake Side Power Project is another PacifiCorp gas-fired electric generating resource located in Utah. It is expected to produce 534 MW of power at a project cost of $330 million.

Q. Is cost recovery of the Lake Side Power Project at issue in this case?

A. No. The Company is not requesting the recovery of costs related to this acquisition in this proceeding. However, this project is another example of how PacifiCorp is planning to serve significant demands for electricity from its Eastern Control Area, without a showing that these projects provide substantial benefits to the Western Control Area, in general, or to Washington in particular.

Q. How would the Revised Protocol treat the Lake Side Power Project?

A. The Revised Protocol would treat this project as a system-wide, "rolled-in" resource, and would allocate the cost of the project to all jurisdictions, including Washington.

Q. Have you reviewed PacifiCorp's application and prepared testimony before the Utah commission for certificate of convenience and necessity?

A. Yes. The Utah commission has assigned the matter Docket No. 04-035-30.

Q. What did you find?

A. As with the Currant Creek Project, PacifiCorp is acquiring the Lake Side Power Project to specifically meet the needs of the Eastern Control Area. For example, PacifiCorp's application in Docket No. 04-035-30 states that: "Rising retail demand in the East portion of the system has been a principal factor contributing to an increasing gap between load and resources." PacifiCorp also states that if the Company is unable to proceed with the project, "…the Company and its customers would be exposed to the volatility in the wholesale power market, high transmission costs associated with delivering power to customers in Utah, and potential adverse impacts on service reliability."

The Company's testimony supporting the Application has many other references to the needs of the Eastern portion of the Company's system. For example, in his prepared testimony in that docket, Company witness Mr. Furman states: "Because of transmission constraints, the East portion of the system requires more in-state physical resources to fulfill the Company's obligation to serve load. These constraints limit imports from other electrical systems and create a need to buy or build additional capacity. More recent load forecasts indicate an even larger resource gap for the East than was projected in the 2003 RFP."

Q. What conclusions are appropriate to draw from PacifiCorp's justification for the Lake Side Power Project?

A. Like the West Valley Lease, Gadsby Peaker and Currant Creek, PacifiCorp's case for the Lake Side Project fails to address West side needs or how benefits of these resources may accrue to the West, sufficient to warrant the system-wide, "rolled-in" based allocation of the project costs.

Q. Did the Company's Utah Lake Side Application before the Utah commission identify other agreements that have been entered into specifically for Eastside needs?

A. Yes. In PacifiCorp's prepared testimony supporting the Lake Side Application, Company witness Mr. Tallman identifies several power supply the Company entered into specifically to serve the East portion of PacifiCorp system. These include several shorter term summer purchases, a significant 100mw purchase for 2006/2007, and a 100 MW long-term purchase from Deseret Generation and Transmission Cooperative. Deseret was a bidder in the earlier 2003-A RFP. However, PacifiCorp made the Deseret purchase outside that RFP process.

In addition, Mr. Tallman describes the possibility of a significant amount of Utah Qualifying Facilities (QF) power that may be available no later than June 2007.

Q. How would the Revised Protocol allocate the cost of these other agreements?

A. Under the Revised Protocol, the costs associated with each of these agreements would be allocated on a system-wide, "rolled-in" basis to all jurisdictions, including Washington.

e. Other Company acquisitions

Q. Has PacifiCorp issued any recent RFPs for Western Control Area power?

A. Yes. PacifiCorp issued RFP 2003-B in February 2004 for renewable resources. In that RFP, PacifiCorp sought a total of 1100 MW of new renewable resources over seven years.

Q. In that 2003-B RFP, did PacifiCorp treat Western Control Area renewable resources different from Eastern Control Area renewable resources?

A. Yes. In the Company's 2003-B RFP, PacifiCorp split the requested renewable generating resources into Westside and Eastside portions. In an earlier

Bidding Workshop, the Company spelled out the specific points of delivery for the Company's Western Control Area and the Eastern Control Area.

Q. What is the significance of this structure of the 2003-B RFP, and the separate delivery points for the Eastern and Western Control Areas?

A. This once again demonstrates that the Company evaluates resource acquisitions on a separate basis for Eastern and Western Control Areas.

4. Conclusions on PacifiCorp's use of the IRP and RFP processes

Q. Please summarize why Staff has provided such an exhaustive review of how PacifiCorp has used the IRP and RFP processes.

A. One of PacifiCorp's principal justifications for the Revised Protocol is the simple statement that the Company: "plans and operates its generation and transmission on a six-state integrated basis in a manner that minimizes costs to all its retail customers." *Direct Testimony of Mr. Duvall, Exhibit No. ___T (GND-1T), at 7.* The critical question is whether PacifiCorp's statement is consistent with the way the Company actually plans and acquires new resources.

In fact, the Company's IRPs, RFPs, and the documents generated by the Company during recent project acquisition processes indicates that PacifiCorp does not plan its system on an integrated basis. In fact, PacifiCorp acquired several major generating projects to meet the needs of its customers in the Eastern Control Area. In doing so, and PacifiCorp did not consider or quantify how those projects met needs, or provided significant benefits, to the Western Control Area in general, and Washington in particular. The Company made no analysis at all showing that these projects were least cost resources for the Western Control Area.

Accordingly, the Revised Protocol's system-wide, "rolled-in" treatment of new resources is not consistent with the manner in which the Company planned for, justified, and acquired these new resources.

Q. Mr. Furman, the Company's policy witness in this case, testifies that: "the decision to acquire several new generating resources in Utah helped to avoid millions of dollars in purchases and transmission costs, while providing dispatch flexibility and other benefits." ***Exhibit No. ___T (DNF-1T) at 31, lines 14-16.*** **Is that statement supported by the IRP and RFP and related Company documents that you reviewed?**

A. No. The Company's documents consistently show that the Company planned and justified these new projects based on the growing demand for power in the Eastern Control Area. Staff found no Company analysis that identified, let alone quantified, any "dispatch flexibility and other benefits" to Washington or the Western Control Area. In sum, PacifiCorp has failed to demonstrate that these projects were acquired to meet Washington's needs, or to provide quantifiable benefits to Washington customers sufficient to warrant the Revised Protocol's treatment of the costs of those resources.

F. Other Revised Protocol Issues

Q. What do you cover in this section of your testimony?

A. I have addressed the main issue on cost allocations: whether the basic underpinnings of the Revised Protocol are valid, given how the Company actually plans, operates, and acquires resources. In this section, I address Staff's concerns regarding specific elements of the Revised Protocol.

Q. What specific elements do you address?

A. I address the following elements: 1) How the Revised Protocol allocates Seasonal and System resources without any showing by PacifiCorp that the resource is needed or even able to serve Washington; 2) How the Revised Protocol fails to treat the Company's Mid-Columbia contracts appropriately; 3) How the Revised Protocol imposes significant administrative burdens in order to protect Washington ratepayers; and finally, 4) Why the Revised Protocol is not sustainable.

1. Seasonal and System Resources

Q. What are Seasonal and System Resources?

A. Seasonal Resources are the Company's single cycle combustion turbines, seasonal purchased power contracts, and Cholla Unit 4. System Resources are a "catch-all" category that contains all Company resources except Seasonal Resources, Regional Resources, state-specific resources, and certain Direct Access Purchases and Sales. *Revised Protocol, Exhibit No. ___ (DLT-2) at 20 and 21.*

Together, Seasonal and System Resources comprise the majority of the Company's resource costs.

Q. How does the Revised Protocol treat this majority of resource costs PacifiCorp incurs to provide electricity?

A. The Revised Protocol "rolls-in" Seasonal and System Resources and allocates a portion of these resources to all PacifiCorp states, including Washington.

Q. Is that treatment appropriate?

A. No. The Revised Protocol fails to consider whether a particular Seasonal or System Resource can actually serve each of the jurisdictions that are allocated the costs. Nor does the Revised Protocol consider whether a Seasonal or System Resource was acquired, or will be acquired, to serve specific loads in a specific state or control area.

This is a clear example of how the Revised Protocol fails to consider cost causation.

Q. Are there any other problems with how the Revised Protocol allocates Seasonal Resources and System Resources?

A. Yes. Under the Revised Protocol, the allocation of these resource costs to each state will change as the loads of each state change. For example, while a state with fast-growing loads relative to other states would be assigned a share of new resources acquired to meet its needs, it would also be allocated a larger portion of existing lower cost resources, such as those located in another control area. The net result is that the Revised Protocol makes it difficult, if not impossible, to accurately relate the revenue requirement effects of actual load growth to the jurisdiction that is causing that load growth. Instead of paying for the costs it clearly causes (from resources specifically acquired to meet its needs), a fast growing state would get the benefit from shifting a portion of those costs to other states, and at the same time it would get the benefits of being allocated a larger share of lower cost resources in other jurisdictions; resources that may not even be able to serve that load.

Q. How should Seasonal and System Resources be allocated?

A. These resources should be allocated based on application of cost causation principles. The Company should consider what states caused the Company to acquire these resources, including what states get the benefit of these resources, and how the Company operates the resource to provide those benefits. The Revised Protocol considers none of these factors.

2. Mid-Columbia Contracts

Q. How does the Revised Protocol allocate PacifiCorp's costs associated with the Company's Mid-Columbia hydro contracts?

A. First, the Revised Protocol allocates to Oregon all or large portions of the benefits of certain of the Mid-Columbia contracts. The remainder is allocated system-wide to all states.

Specifically, Oregon is assigned 100 percent of the energy from the Company's Priest Rapids Power Sales Agreement, as well as almost 77 percent of the energy from the Company's Wanapum Dam Power Sales Agreement. In addition, Oregon is allocated its system-wide share of energy from the Rocky Reach and Wells dams. *Revised Protocol, 2nd page of Appendix F, "Percent" side,"Oregon" lines, Exhibit No. ___ (DLT-2) at 71.*

The Eastern Control Area states of Idaho, Utah, and Wyoming are allocated a significant portion of the remaining benefits of these contracts, with Utah receiving over 40 percent of the energy from both Rocky Reach and Wells contracts. Washington's allocation is limited to the 23 percent remaining portion of the Wanapum energy, and its system-wide share, approximately 8.65 percent, of Rocky Reach and Wells. *Id., "Washington" lines.*

Under the Revised Protocol, this allocation scheme also applies to any replacement contracts related to the Priest Rapids and Wanapum projects.

Q. Is this an appropriate treatment for allocating the Mid-Columbia contract benefits?

A. Absolutely not. Throughout the MSP process, Washington has steadfastly maintained that the costs and benefits of both the Northwest Hydro system and the Mid-Columbia contracts should remain within the bounds of the former Pacific Power & Light jurisdictions.

Indeed, in the original Protocol, which the Company filed in its 2003 Washington General Rate Case, Docket No. UE-032065, the Company treated both its owned-Hydro resources in the West and its Mid-Columbia contracts (including replacement contracts) as an endowment to the former Pacific Power & Light states, including Washington. This treatment reflected the positions of the parties to that point.

The Revised Protocol's different treatment of these resources was established only after Washington's participation in the MSP ended and the states of Utah and Oregon continued discussions with PacifiCorp.

Q. Did Staff inform the MSP participants that the Revised Protocol's treatment of Mid-Columbia contracts was unacceptable?

A. Yes. At various times since the Revised Protocol was fully developed and presented, Staff has expressed its concerns regarding the treatment of these resources.

Q. What explanation has PacifiCorp given to explain why Oregon gets 100% of the PacifiCorp's entitlement to power from the Priest Rapids Project, and 75% of the Wanapum Project?

A. According to a memo prepared by counsel for PacifiCorp and provided to MSP participants, PacifiCorp apparently relies on language in the recently expired Priest Rapids Power Sales Agreement which states that PacifiCorp's purchases from the Priest Rapids dam were being made: "solely from the gross revenues of [PacifiCorp's] light and power system, for the benefit of consumers in the State of Oregon." The language in the Wanapum agreement is similar, except that consumers in Washington were included in the above statement.

Q. Is PacifiCorp's position reasonable?

A. No. The contract language at issue was addressing the responsibility of the project owner to make a reasonable portion of the output available for sale to neighboring states. The language in the Priest Rapids contract did not state that Oregon was the "sole" beneficiary. The language was to satisfy legislation approving construction and operation of the projects requiring that power be offered to neighboring states. That requirement could be satisfied without 100 percent of the power going to Oregon.

Q. On an operational basis, did PacifiCorp treat the power from the Priest Rapids and Wanapum Projects consistent with how the Revised Protocol allocates the benefits?

A. No. While the Revised Protocol assigns to Oregon 100 percent of the Priest Rapids Project and 75 percent of the Wanapum Project, PacifiCorp supplies no dedicated transmission line to carry that amount of power from either the Priest Rapids Project or the Wanapum Project to Oregon. Instead, that energy is integrated into the Company's Western Control Area. Within that control area, neither the Company, nor Oregon, "color-code" the electrons from these dams.

Q. What are some of the logical consequences of a 100 percent allocation of the output of the Priest Rapids Project to Oregon?

A. If the Company wishes to assign to Oregon 100 percent or a large majority of the benefits from these projects, it should assign the costs of all transmission necessary to get that power to Oregon, including the cost of the significant transmission resources necessary to transfer the power to PacifiCorp's Southern Oregon service territory.

Q. Does the Revised Protocol assign to Oregon those transmission costs?

A. No.

Q. Assuming PacifiCorp's interpretation of the Priest Rapids contract is correct, are there other reasons why the Revised Protocol's treatment of the Priest Rapids energy is not appropriate?

A. Yes. The Priest Rapids contract which PacifiCorp allocated 100% to Oregon expired in October 2005. The new contract does not contain the language that PacifiCorp relied on for that treatment. Consequently, even if the language from the prior Priest Rapids contract justified a 100% assignment of the energy from that project to Oregon, that language is no longer operative.

In other words, PacifiCorp's prior justification for allocating 100 percent of PacifiCorp's share of the Priest Rapids project to Oregon no longer applies, assuming it ever applied.

Q. How should the cost of the Company's Mid-Columbia contracts and replacement contracts be allocated?

A. These resources should be allocated to the states in the Western Control Area only. The delivery point of energy associated with these contracts remains in the Western Control Area. While there are no contractual or other legal constraints that limit the benefits from these projects to the Pacific Northwest, the manner in which these projects are actually operated, plus the transmission constraints I previously discussed, means these are Western Control Area resources. The Company itself has determined many times over, that power from the West cannot be reliably counted on to serve the growing demands of the Easter Control Area.

In other words, the entire Western Control Area has historically benefited, and benefits now, from the energy from both the Company owned hydro-electric generation and all of the Mid-Columbia contracts. At the same time, the entire region, including the Company's Western Control Area customers, carries the other burdens of these projects. The benefits of the Company's Western hydro-electric generation and energy from the Mid-Columbia contracts should remain with the former Pacific Light & Power customers, and allocated among the states based on the relative loads of those states.

3. *Administrative burdens*

Q. Please describe the administrative burdens the Revised Protocol places on the Commission.

A. The Revised Protocol is a rather complex allocation method that will be difficult to administer. There are several elements in the Revised Protocol that require either significant ongoing participation, or a level of monitoring and analysis by Staff, in order to protect Washington ratepayers from potential actions in other jurisdictions.

Q. Can you give some examples?

A. Yes. In regards to ongoing participation, the Revised Protocol sets up a MSP "Standing Committee," whose purpose is to discuss and monitor emerging inter-jurisdictional issues. In addition, separate workgroups can be formed to address specific issues that either have been raised or will be raised in the future. *Revised Protocol, Exhibit No. ___ (DLT-2) at 13.*

For example, in addition to the Standing Committee, there have been workgroups addressing load growth issues and the development of a working Hybrid (or control area based) model. All of these efforts require significant Commission resources.

Q. What other Revised Protocol elements place administrative burdens on the Commission?

A. The Revised Protocol requires the Commission to resolve several issues related to: 1) The acquisition and assignment of new resources; 2) Special Contracts; 3) QF Contracts; 4) Portfolio Standards; and 5) The treatment of Direct Access Programs.

Q. What administrative concerns are there related to the acquisition and assignment of new resources?

A. The Revised Protocol States that the Company shall plan and acquire new Resources on a system-wide, least cost, least risk basis and that prudently incurred investments in Resources will be reflected in rates consistent with the laws and regulations in each state. *Exhibit No. ___ (DLT-2) at 1.2*

Leaving behind Staff's point that the Company does not plan or acquire resources on a system-wide basis, as I discussed earlier, under the system-wide, "rolled-in" methodology of the Revised Protocol, Washington is assigned a portion of costs of each new resource PacifiCorp acquires. This requires Staff to evaluate the prudence of significant resources that the Company does not acquire to meet Washington's needs for power.

For example, in the case of the recently-acquired West Valley, Gadsby Peaker, Current Creek, and Lake Side resources, the Company's resource acquisition processes did not involve Washington at all. The Company acquired these resources specifically to meet Eastern Control Area needs.

The Revised Protocol appears to place the burden on Staff and other parties to demonstrate, in a litigated rate case, that a resource should not be allocated to Washington, rather than the Company carrying the burden of demonstrating the prudence for purposes of Washington's electric service.

Q. Turning to Special Contracts, please first describe how the Revised Protocol treats Special Contracts?

A. Under the Revised Protocol, Company revenues from Special Contracts are assigned to the state where a special contract customer is located, and the loads of the special contract customer are included as part of that state's load when determining allocation factors. *Exhibit No. ___ (DLT-2) at 9.* Any revenue shortfalls for special contract customers are then the responsibility of each state.

However, special contracts with ancillary services are treated differently. Generally, discounts from tariffs prices or payments to the customer as a result of the contracts somehow providing ancillary services, will be "rolled-in," equivalent to a System Resource. *Id. at 64.*

Q. What administrative burden does the Revised Protocol create by this treatment of special contracts with ancillary services?

A. This treatment leaves this Commission with the task of evaluating the terms and conditions of each special contract in each other jurisdiction, in order to insure that appropriate costs are assigned to Washington under the revised Protocol. Again, the valuation of a contracts attributes may be different for one state than another. It also appears that the commission in each state will have the burden to analyze each contract for prudence. In addition, the Revised Protocol has no procedure for resolving disagreements on this issue.

Q. What are "QF" contracts, and how are they treated under the Revised Protocol?

A. A "QF" refers to a Qualifying Facility, which is a term defined under the Public Utility Regulatory Policies Act of 1978 (PURPA). Under PURPA, the states determine how the utility's acquisition of QFs is administered.

The Revised Protocol includes QF contracts as "State Resources," and it allocates state-specific QF contract costs differently, depending on whether the QF contract is entered into, renewed or extended before May 21, 2004 ("Existing QF Contracts"), or after that date ("New QF Contracts").

"Existing" QF Contract costs are first allocated on a system-wide basis and then adjusted using a procedure that compares the state specific QF costs to the embedded costs of the Company's system, in order to determine an Embedded Cost Differential Adjustment. The amount of the adjustment is assigned to the state where the QF is located. "New" QF Contract costs are simply "rolled-in" on a system-wide basis, with any costs that are determined to exceed that which the Company would otherwise have incurred, being assigned on a situs basis. However, the Revised Protocol does not detail when and by whom that determination will be made. *Exhibit No. ___ (DLT-2) at 6-7 and at 18 and 20.*

Q. What is the administrative burden imposed by the Revised Protocol's treatment of QF contracts?

A. Staff will need to review Qualifying Facilities contracts applicable to other states in order to insure that cost shifting does not occur as the result of specific state policies regarding QFs. In addition, for Washington there may be timing issues on what constitutes an "Existing" or "New" QF contracts for purposes of treating the costs under the Revised Protocol.

Q. What are "Portfolio Standards" under the Revised Protocol?

A. Portfolio Standards are typically legislated requirements for specific types of resources that a utility must acquire. An example of a portfolio standard is a state requirement that PacifiCorp have 3 percent of its power consisting of renewable energy resources.

Q. How does the Revised Protocol treat PacifiCorp's costs of complying with state portfolio standards?

A. The Revised Protocol includes this item in the category of "State Resources." For costs related to any portfolio standards that may be imposed by individual state legislation, the costs of meeting that standard are assigned to that state, but only to the extent the cost exceeded what PacifiCorp would otherwise have incurred in acquiring "Comparable Resources," which itself is a defined term. Again it is not clear when and by whom such evaluations are made. *Exhibit No. ___ (DLT-2) at 6 and at 17.*

Q. What is the administrative burden imposed by this treatment?

A. Portfolio requirements may be different across the PacifiCorp's states, and they may not represent least cost options available to the Company. If the costs PacifiCorp incurs to meet such standards are simply "rolled-in" to all jurisdictions, there is a potential for cost-shifting to occur.

To prevent cost-shifting, each commission would have to evaluate the effect on PacifiCorp's resource costs resulting from portfolio standards imposed by each state, and then evaluate whether any resultant costs exceed the costs the Company would otherwise have incurred. This is an extremely complex undertaking. And if, for example, Washington Staff could not make that showing, all of the costs would be assigned on a "rolled-in" basis.

Q. What are "Direct Access Programs" and how are they treated under the Revised Protocol?

A. Direct Access Programs are programs that permit retail customers to purchase electricity directly from a supplier other than PacifiCorp. *Revised Protocol, Exhibit No. ___ DLT-2) at 18.*

The Revised Protocol contains language on when and how the loads affected by direct access are to be treated for allocating existing and new resources. The most interesting feature related to direct access is the ability of the state with direct access customers to unilaterally determine for its ratemaking purposes the value or cost resulting from the departure of load. It appears that some transition charge or credit representing the gain or loss of the sale of a "Freed-Up" resource will be distributed to those customers on a situs basis only in that state choosing direct access. *Id. at 11*

The Revised Protocol also states that it is up to the state implementing direct access programs to propose such an allocation scheme that is "no-harm" to the other states. *Id.*

Q. What is the administrative burden imposed by this treatment?

A. This leaves the commissions of each state that does not have a Direct Access Programs with the responsibility of having to analyze, on a continuing basis, the effect of actions (determining gains or losses) of another commission to insure that the claimed benefits of the Revised Protocol are maintained.

In addition, it is questionable whether this principle of situs allocation of "Freed-Up" resource benefits is consistent with the Protocol's over-riding "rolled-in" element. The situs assignment of certain resource benefits only seems appropriate and consistent if the resource cost were originally assigned on a situs basis and not on some "rolled-in" basis. This inconsistency, coupled with the need to monitor the actions of another commission, create a significant administrative burden.

4. *Sustainability*

Q. Are there other specific elements of the Revised Protocol that concern Staff?

A. Yes. Staff has is a significant concern that the Revised Protocol is not sustainable.

Q. Does the Revised Protocol contain provisions that address sustainability?

A. Yes. The Revised Protocol refers to the role of the MSP Standing Committee, which is formed to consider such possible amendments to the Revised Protocol that would be equitable to the Company and customers in all states. Amendments are approved only if each of the commissions who had previously ratified the Revised Protocol ratifies the amendment. *Exhibit No. ___ (DLT-2) at 13.*

Q. Is the Revised Protocol sustainable?

A. I doubt it. Based on Washington's participation in the MSP, a review of testimony and orders in the various jurisdictions, and a continuing review of Revised Protocol related documents, there is nothing that leads me to conclude that the Revised Protocol will be sustainable in the long-term.

Moreover, any allocation method such as the Revised Protocol, which is not based on cost causation principles, will not produce fair results over time, and therefore it will not be sustainable.

Q. Does the Revised Protocol itself indicate the method is not likely to be sustainable?

A. Yes. As I indicated earlier, according to the Revised Protocol: "A party's initial support or acceptance of the Protocol will not bind or be used against any party in the event that unforeseen or changed circumstances cause that party to conclude that the Protocol no longer produces just and reasonable results." *(Emphasis added). Exhibit No. ___ (DLT-2) at 14, lines 9-13.* Accordingly, it is possible for a state to later "opt out" of the Revised Protocol if it is not satisfied with the results.

Q. Is ratification of the Revised Protocol by Washington necessary for its use by Oregon, Utah, Wyoming, and Idaho?

A. No. The Revised Protocol states that: "The Company will continue to bear the risk of inconsistent allocation methods among the states."

However, the use of the Revised Protocol by Oregon, Utah, Wyoming and Idaho is conditioned upon the final ratification, without deletion or alteration of material form, by those states. As I understand it, if one of those states opts out, the other states need not follow the Revised Protocol.

As I described earlier in my testimony, the Utah, Oregon and Idaho commissions imposed caps and other conditions in their orders adopting the Revised Protocol. There is a very real possibility that one or more of these states may decide not to follow the Revised Protocol.

Historically, Utah has already unilaterally adopted allocation methods for purposes of setting rates, which was counter to the approaches being explored by the states and PacifiCorp in joint allocation efforts at that time. In addition, the Utah commission, even in its order in Docket No. 02-035-04 accepting the Revised Protocol, has clearly signaled its intent to use a fully "rolled-in" approach in judging the reasonableness of rates – "We find that the principle-based Rolled-In allocation method and current cost-causation, previously approved by this Commission, remains a valid benchmark to judge the reasonableness of future rates in Utah and will require the Company to continue to file Rollin-In results."[7]

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[7] *Re Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket No. 02-035-04, Report and Order (Utah PSC, December 14, 2004) at 40.

The Oregon Commission's interest in developing and exploring the Hybrid approach also brings into question the sustainability of the Revised Protocol.

G. Revised Protocol Workgroups

Q. What allocation issues continue to be examined under the Revised Protocol?

A. The Revised Protocol created two separate workgroups that continue to examine allocation issues. The Load Growth Workgroup has been charged with evaluating load growth-related issues. The Hybrid Workgroup is working to develop a Hybrid allocation methodology pursuant to the order of the Oregon commission accepting use of the Revised Protocol.

Staff has been monitoring these workgroups via meeting summaries, and other material provided by the Company since these workgroups were created.

1. Load Growth Workgroup

Q. Please describe the efforts of the Load Growth Workgroup.

A. The Load Growth Workgroup is evaluating issues such as cost-shifting due to load growth mechanisms to address such cost shifting.

Q. What have been the results of the Load Growth Workgroup's efforts?

A. The Load Growth Workgroup's efforts have focused on various structural mechanisms to remedy load growth related cost shifts. The participants have recognized certain shortfalls of the Revised Protocol that have concerned Staff from the beginning of the Multi-State Process.

For example, in a position paper submitted to the Workgroup by Mr. Compton, one of the Utah participants, states:

> There seems to be an operating MSP consensus that slow-growing states ought not to have their allocated costs elevated owing to the costs that PacifiCorp incurs to accommodate other states' (particularly Utah's) faster rates of growth. Hence the task to develop some "structural protection mechanism" that would insure against slow-growth states – and/or the PacifiCorp shareholders for that matter – bearing an unreasonable share of the incremental costs caused by growth.

The paper goes on to describe several of the mechanisms the Workgroup group is examining, including: 1) The use of the Hybrid (control area based) model instead of the "rolled-in" based Revised Protocol; 2) The direct assignment (or "tiering") of resources; 3) The assignment of costs above the average embedded costs to fast growing states; and 4) Direct allocation adjustments using “transfer payments” to offset the over/under payment of costs.

The MSP Standing Committee has subsequently ordered the Load Growth Workgroup to continue efforts to define and develop a viable “embedded cost differential” based method as a structural protection mechanism. The Company, in its “Load Growth Report” (October 20, 2005) claims that the current studies show that the Revised Protocol protects the slow growing states from potential costs shifts associated with a faster growing states load growth. However, that Report also points out that the Revised Protocol requires that a structural protection mechanism be developed if future studies indicated that such a mechanism is warranted. In addition, the “studies” the Company refers to in the Load Growth Report are the same results-oriented revenue requirement forecast analyses I discussed earlier in my testimony.

Finally, it appears that there is some disagreement between the Company and some of the Workgroup participants regarding the need for additional studies to determine whether or not the full benefits from hydro generation are properly being allocated. At the time this testimony is being prepared, the final conclusions and work product of the Load Growth Workgroup is uncertain.

Q. Does the Revised Protocol supported by the Company in this case include any structural protection mechanisms to address cost shifting due to load growth?

A. No.

Q. Should the Commission adopt the Revised Protocol based on the prospect of an acceptable outcome from the Load Growth Workgroup?

A. No. Even though a structural protection mechanism is not contained in the version of the Revised Protocol supported by the Company in this case, any structural protection mechanism is really only a "band-aid" aimed at addressing the symptoms of the problem, rather than a cure.

The better approach is to adopt a cost allocation model that is based on an appropriate relationship between cost causation and cost recovery.

2. *Hybrid Workgroup*

Q. Please describe the Hybrid Workgroup.

A. As I mentioned, the Hybrid Workgroup is a separate workgroup established as a result of an order by the Oregon Commission accepting use of the Revised Protocol.

Q. What have been the results of the Hybrid Workgroup's efforts?

A. No consensus Hybrid model has been developed. The Workgroup initially focused on the assignment of resources to the Eastern and Western Control Areas. Intra-control area equity issues also appear to be a major topic of interest of the Workgroup, along with the issue of pricing of energy transfers between control areas.

Q. Is the Hybrid Workgroup a viable workgroup at present?

A. The answer is not clear. Recently, PacifiCorp advised the Hybrid Workgroup participants that further refinement of the Hybrid Method in response to the Oregon commission order would be carried out by the Company and the Oregon participants only. The Company therefore disbanded the Hybrid Workgroup, although some participants appear to question the Company's actions.

Q. Is Staff encouraged by the Hybrid Workgroup's efforts?

A. No. Although the Hybrid model better represents the way the Company plans and operates its system, Staff has many concerns regarding the efforts of this workgroup. For example, the primary evaluation tool used by the Hybrid Workgroup continues to the results-oriented revenue impact studies, which compares future estimated revenue requirements under the Hybrid Model with results using several other allocation methods, none which have been accepted by this Commission.

In other words, each element of the Hybrid methodology appears to be evaluated not on how it reflects cost causation, but rather on it impacts revenue requirements, using other methods as standards of comparison.

This is reflected in concerns expressed by some participants that it is "troubling" that the Hybrid models being examined do not follow the results of the Revised Protocol methodology. In fact, the Company has gone so far as to present information that compares "Base Case Hybrid" with "Base Case Revised Protocol," coupled with some mechanisms to bring East and West Hybrid differences closer to Revised Protocol.

This is ample evidence that the focus of the Hybrid model analysis is not on cost causation principles, but the palatability of results, using the Revised Protocol as the standard of comparison. As I have testified, that is not an acceptable approach.

Q. Have any of the Hybrid Workgroup participants also expressed any concerns about this results-oriented approach?

A. Yes. According to page 2 of the July 18, 2005 Hybrid Workshop Meeting Summary, which PacifiCorp provided to Staff:

> Concern was expressed that the potential adjustments suggested, in order to bring each control area (and individual state) closer to Revised Protocol results, were becoming ad-hoc adjustments driven by the results (to make the dollars work) and that it might be difficult to keep track of all the adjustments.

Q. Is that a valid concern?

A. Yes. The Hybrid Model should be evaluated on whether it best matches cost causation and how PacifiCorp plans and operates its system, not on how it compares to the Revised Protocol.

Q. Are there other instances of workgroup participants expressing concern about how the Hybrid Model is being developed in the Workgroup?

A. Yes. My Exhibit No. ___ (APB-11) contains a recent letter to the Company from the Industrial Customers of Northwest Utilities (ICNU) that outlines its concerns regarding statements and positions described in workgroup meeting summaries. In the second paragraph of that letter, ICNU compares the “new” Hybrid Model being developed in the Workgroup to the original hybrid model efforts:

> ICNU’s representatives have never agreed to the revisions to the original Hybrid methodology because the lacked substantial evidence

> supporting the changes to resource allocation. From our perspective, these changes were proposed and supported as part of a misguided attempt to turn the Hybrid methodology into something similar to the Revised protocol. For example, the changes in resource allocation in the Hybrid methodology have been results oriented and adopted to produce a result that is as close as possible to the Revised Protocol and Rolled-in methodologies.

ICNU goes on to provide several examples of questionable resource allocations under the latest Hybrid Model.

Q. Should the Commission adopt the Revised Protocol based on the prospect of an acceptable model being developed in the Hybrid Workgroup?

A. No.

H. Recommendation

Q. What is Staff's recommendation regarding the use of the Company's Revised Protocol proposal for purposes of determining Washington rates?

A. Staff recommends the Commission reject the Revised Protocol as the basis for inter-jurisdictional cost allocations for purposes of determining Washington rates.

Q. Are caps or other conditions the long-term answer for addressing the shortcomings of the Revised Protocol PacifiCorp filed in this docket?

A. No. Caps or conditions are not a long-term solution for addressing the shortcomings of the Revised Protocol. A long-term cost allocation system that meets basic principles of cost causation should not need caps or other conditions. The fact that three other states have adopted the Revised Protocol only by conditioning that approval with caps or other conditions, confirms that the Revised Protocol does not reflect these principles.

However, specific conditions or adjustments may be appropriate in order to utilize elements of the Revised Protocol as a transitional solution to the inter-jurisdictional cost allocation problem.

Accordingly, Staff is recommending an "Amended Revised Protocol," with certain allocation related power supply adjustments, as a compromise solution to addressing Staff's most immediate concerns, at the same time allowing for the future development of a more robust, long-term solution.

V. ALTERNATIVE COST ALLOCATION MODELS

Q. Before describing the details of Staff's proposed allocation method, please describe the other alternative cost allocation methods Staff considered.

A. Staff considered several cost allocation models that could be used for purposes of determining Washington rates. These alternatives ranged from relatively simple models, to more complex models that would require additional effort to fully develop. For purposes of this discussion, I will label these alternatives: 1) The Full Requirements Contract Model; 2) The Resource Portfolio Model; and 3) The Simplified Control Area Model. Any of these models, if properly designed, would reasonably allow the Company to recover the costs it actually incurs to serve Washington.

I review the principle features of each of these models because they remain viable long-term options for determining PacifiCorp's costs to serve Washington.

A. Full Requirements Contract Model

Q. Please describe the principle features of a Full Requirements Contract Model.

A. A Full Requirements Contract Model could contain some features in common with the Revised Protocol. The primary difference would be that power costs would be assigned based on a "theoretical" full requirements contract.

Overall, the Full Requirements Contract Model would have the following features:

1. Distribution costs would be assigned to Washington on a situs, or directly allocated basis. This is the same as the Revised Protocol.
2. Transmission costs would be assigned to Washington based on the actual transmission facilities identified as being necessary to serve Washington customers.
3. Administrative and General Costs would be assigned to Washington on a combination of factors, recognizing that the recovery of Washington's fair share of power supply related fixed costs are captured through a "full requirements contract" rather the traditional "return of rate base" method.
4. Power Supply Costs would be determined for Washington based on the cost of a "theoretical" full requirements contract. The "contract" rate could be determined in a number of ways, representing an agreed upon number of resources identified as being necessary to serve

Washington. Both the fixed and variable costs of those resources would be recovered through the contract rate. This model in some ways reflects the Company's Structural Re-alignment Proposal previously submitted to this Commission, and which I described earlier.

Q. What are the advantages of the Full Requirements Contract Model?

A. The determination of the costs to serve Washington would be relatively simple to develop, efficient to administer. In addition, a simplified power cost adjustment mechanism could easily be implemented in conjunction with this model, to track changes in agreed-upon contract parameters, including the effects of variable water conditions.

Q. What are the disadvantages of this model?

A. If the determination of the requirements contract costs is limited to a few easily-identified resources, there could be increased risk for both the customer and the Company. This model does not take into consideration all of the benefits or risks of wholesale market transactions, either sales or purchases, entered into by the Company. The potential benefits of secondary sales for a largely hydro-based Western Control Area system may be difficult to capture as well. However, this model, coupled with a properly designed power cost adjustment mechanism, should be able to address most of these concerns.

Q. Has Staff developed a working version of this model?

A. No. Staff has identified a number of Western Control Area resources which could form the basis of a "theoretical" full requirements contract. However, the development of such a proposal is best carried out with the participation and cooperation of the Company.

B. Resource Portfolio Model

Q. Please describe the principle features of a Resource Portfolio Model.

A. A Resource Portfolio Model is an extension of the Full Requirements Contract Model I just described. As more and more resources are added in order to capture additional potential benefits of the Western Control Area system, it becomes apparent that a more inclusive model may be appropriate for developing costs to serve Washington.

Overall, the Resource Portfolio Model has the following features:

1. The assignment of Distribution, Transmission, and Administrative and General costs would be in the same manner as the Full Requirements Contract Model.

2. The Power Supply component of Washington's costs would be determined by calculating the weighted costs of a number of resources identified as serving Washington. The beginning basis would be resources located in the Western Control Area, although other Company resources could be added if the Company could show they were necessary and able to meet Washington's needs.

Both the fixed and variable costs of the resources in the portfolio would be considered to determine a total resource "rate" for each resource, given accepted assumptions regarding average generation and fuel costs. Major wholesale contracts and short-term energy transactions could be included in the portfolio mix.

The total "Resource Portfolio" rate for purposes of determining Washington's power supply costs would be calculated by weighting the portfolio mix. A beginning point for the weighting exercise could be a factor that relates the percentage of Washington load within the Western Control Area to the generation of each resource or contract in the portfolio.

Q. What are the advantages of the Resource Portfolio Model?

A. The assignment of power supply related costs based on a portfolio of resources would allow for the efficient determination of generation-related costs to serve Washington ratepayers. Resources can be added, or subtracted, to accommodate the prudent acquisition of resources acquired to serve Washington.

Also, the fixed and variable costs of resources can be updated. The weighting of the portfolio's resource mix can be changed to accommodate changes in operating characteristics of generating assets or changes in contract terms.

Costs for resources outside the Company's Western Control Area can be included in a portfolio mix if it can be demonstrated that the capacity and/or energy is needed, at least cost, and can be delivered on a firm basis. Non-firm transactions can also be accommodated on a similar basis.

This "portfolio" approach to developing assigned power costs is also fully compatible with the Company's present IRP and RFP processes. In addition, as with the Full Requirements Contract Model, an efficient and easily administered power cost adjustment mechanism could be developed to address variations in certain elements of the resource portfolio.

Q. What are the disadvantages of the Resource Portfolio Model?

A. As the portfolio mix gets more and more extensive, the limits of a relatively "static" approach of looking at net resource costs to capture all of the system benefits becomes more apparent. A resource portfolio approach alone would not capture the dynamic benefits of excess capacity and energy sales resulting from resources in a timely manner. For a hydro-based system, or a system with significant excess capacity, this could be a significant benefit that may not be captured using this model.

However, a properly designed power cost adjustment mechanism may be able to capture many of these benefits, in addition to variations in costs.

Q. Has Staff developed a working version of this model?

A. No. Staff has identified a number of Western Control Area resources which could form the basis for a portfolio of resources serving Washington. However, again, the development of such a proposal is best carried out with the participation and cooperation of the Company.

C. Simplified Control Area Model

Q. Please describe the principle features of the Simplified Control Area Model.

A. The Distribution, Transmission and A&G costs would be determined in the same manner as the other methods I described.

As to power supply costs, the Simplified Control Area Model resembles the "Hybrid" model that has been a topic of discussion throughout most of the Multi-State Process, and now in the Revised Protocol workgroups. However, Staff's concept of the Simplified Control Area Model would not contain many of the features that have evolved through the MSP and the workgroups.

For example, unlike the Hybrid models currently being evaluated in the Hybrid workgroup, Staff's Simplified Control Area Model would not assign resources in a manner that is inconsistent with the way the Company operates its resources in its two control areas. Instead, it would relate the allocation of costs to the manner in which the Company's resources are planned, acquired, and operated.

A Simplified Control Area Model is the next logical progression from a Resource Portfolio Model for purposes of capturing the net benefits from

PacifiCorp's operation of Western Control Area resources. However, unlike the more static portfolio-based models, the Simplified Control Area Model would be based on how the Company actually dispatches its Westside resources to meets its loads within the Western Control Area.

Such a dispatch-based model can capture system benefits over the long-term, including those costs and benefits that flow in each direction between the control areas of the Company.

The Simplified Control Area Model would more readily follow the traditional rate base return plus net power supply expense method of determining total allocated power supply costs for purposes of developing rates.

Q. What are the advantages of a Simplified Control Area Model?

A. The Simplified Control Area Model holds the most promise for having a workable model that actually represents the manner in which the Company's system is planned, acquired, and operated. Without carve-outs or conditions, the Simplified Control Area Model would best follow cost causation principles and represent PacifiCorp's system on a forward-looking basis. A power cost adjustment mechanism could also be implemented that focuses on the variability of Western Control Area costs, rather than unrelated costs in another control area.

Q. What are the disadvantages of a Simplified Control Area Model?

A. From Staff's perspective, the Simplified Control Area Model has the fewest disadvantages. This model is a forward-looking allocation model based on how PacifiCorp plans, acquires resources, and operates its system. On the other hand, the Simplified Control Area Model would most likely require the most administrative effort, from development of the model itself to the review of the model elements in a rate case.

Q. Has Staff developed a working version of this model?

A. No. Although Staff has acquired the modeling tool and an initial data base in order to start development of such a model. However, creating an operating model will require significant additional time and resources. Staff needs policy guidance from the Commission before starting down this path. In addition, as a practical matter, and as with the other models I have described, a more robust tool can be best developed with the participation and cooperation of the Company.

Q. Should some form of the Hybrid model that has been developed in the MSP be used as the basis for a Simplified Control Area Model?

A. No. A new, separate model needs to be developed. The various Hybrid models that have been developed in the MSP contain too many elements that are not cost-based, but have been adopted to appease various parties, or to match results with the results of the Revised Protocol.

In addition, the MSP Hybrid models are based on the Company's GRID model, which is a power supply model PacifiCorp has developed and maintained. The GRID model is not transparent, and Staff also has concerns regarding the ability of GRID to dynamically represent the Western energy markets, which is a requirement when attempting to accurately capture the benefits of resources.

The better path is to use a more transparent and publicly available model as the basis for developing a Simplified Control Area Model for Washington.

VI. STAFF'S RECOMMENDED COST ALLOCATION METHOD

Q. Of the three methods you just described, which one does Staff recommend the Commission adopt for PacifiCorp for purposes of inter-jurisdictional cost allocations?

A. Staff recommends the Commission support the future use of a Simplified Control Area Model for purposes of determining rates in Washington. The Commission should order PacifiCorp to participate with Staff and other interested Washington parties to develop this model. Alternatively, if the Company objects to the development of another allocation model, the Commission could order PacifiCorp to file its future Washington rate cases based on one of the more basic, easier to administer models discussed above.

In the meantime, Staff is prepared to recommend a compromise for this case only.

A. Staff's Amended Revised Protocol

Q. What inter-jurisdictional cost allocation methodology is Staff recommending for purposes of this proceeding?

A. For purposes of this proceeding only, Staff recommends the Commission accept Staff's Revenue Requirements for Washington based on the transitional use of the Revised Protocol, with the adjustments outlined below. I have called this version of the model, Staff's "Amended Revised Protocol."

Staff also recommends the Commission accept the allocation certain Eastside resources and transmission-related costs based on the Amended Revised Protocol's methodology for purposes of this proceeding only, subject to complete review in a subsequent proceeding in order to be consistent with the Simplified Control Area Model or other allocation model not based on the system-wide, "rolling-in" of costs.

Q. Please summarize the changes the Commission should make to the Revised Protocol for purposes of this case.

A. Staff recommends five changes:

1. Adjustment 8.15, **New Eastside Resource Allocation.** The Revised Protocol should be adjusted to exclude all or part of PacifiCorp's costs associated with several large generating resources PacifiCorp recently acquired for purposes of serving Utah loads, not Washington loads.

2. Adjustment 5.5, **Mid-Columbia Contract Allocation.** The Revised Protocol's treatment of Mid-Columbia Purchased Power Contracts should be changed to reflect an appropriate Washington share of costs and benefits from these resources.

3. Adjustment 5.6, **Seasonal Contract Allocation.** The Revised Protocol should be adjusted to remove the costs associated with several Seasonal Contracts the Company acquired to serve Utah loads, not Washington loads.

4. Adjustment 5.7, **QF Contracts Allocation.** The Revised Protocol's treatment of certain "new" Qualifying Facility (QF) contract costs should be changed.

5. **A&G Allocator Adjustment.** Staff provides a more appropriate allocation factor for Administrative and General costs than used in the Revised Protocol. Staff Witness Mr. Tom Schooley is responsible for developing this factor and calculating the resulting adjustment.

Q. Do these adjustments resolve all of the problems with the Revised Protocol?

A. No. Admittedly, these adjustments reflect a "compromise" that allows the use of a form of the Revised Protocol for purposes of this proceeding. Staff's use of the remaining elements of the Revised Protocol, including the allocation of costs associated with the remaining Eastern Control Area resources and Transmission related costs, is for purposes of this proceeding only, as a transition to an appropriate allocation methodology.

Q. Does your list of adjustments address all power supply issues?

A. No. Other Power Supply Expense issues will be discussed later in my testimony.

Q. How do these adjustments affect the Washington Revenue Requirement?

A. The overall effect of these adjustments reduces Revenue Requirements by $12,951,000. The calculation of this figure is presented in the Testimony and Exhibits of Staff Witness Mr. Schooley.

1. Adjustment 8.15, New Eastside Resource Allocation

Q. What adjustment should be made to the Revised Protocol regarding the treatment of PacifiCorp's new Eastside resources?

A. The fixed costs associated with the Gadsby Project and the Current Creek Project should be removed from Washington's allocated share of Net Rate Base.

Washington's allocated share of Annual Depreciation Expense should be decreased to reflect the appropriate treatment of the Annual Depreciation Expense associated with the Washington rate base amounts for the Gadsby Project and the Current Creek Project.

Washington's allocated share of Purchase Power Expense should be decreased to reflect the appropriate treatment of the annual lease expense associated with the West Valley Lease.

Q. What is the basis for Staff's New Eastside Resource Allocation Adjustment?

A. Each of the components of these adjustments represents a compromise by Staff to address the greatest problem with the Revised Protocol: PacifiCorp's failure to justify the system-wide, "rolled-in" treatment of new resource costs, particularly those resources acquired to meet the needs of the Eastern Control Area, principally Utah.

Although this problem applies to virtually all Eastern Control Area resources, Staff's compromise approach to determining rates in this proceeding addresses those resources most recently acquired by PacifiCorp as a result of significant new growth in the Company's Utah jurisdiction. These resources include the Gadsby Peaker Project, the West Valley Lease, the Current Creek Project, and most recently, the Lakeside Project (which is not a subject in this proceeding, but will have a significant effect on future allocated costs).

In order to facilitate the determination of the compromise power supply costs for this proceeding, Staff's adjustment removes only the fixed costs (investment less accumulated depreciation) associated with the Gadsby Peaker Project and the Current Creek Project, as well as the fixed annual costs of the West Valley Lease. For purposes of this proceeding, the variable costs associated with these Eastside resources would continue to be allocated to Washington as normalized Net Power Supply Expense as proposed under the Revised Protocol.

Staff's recommendation is nothing more than a compromise position for this proceeding only that allows the Company to recover some costs associated with the new Eastside resources in Washington rates until an appropriate cost allocation model is developed that is not based on the system-wide, "rolling-in" of resource costs. Under such a model, Washington should not be allocated costs associated with these resources, absent a clear demonstration by PacifiCorp that the power is needed, deliverable, and least cost.

Q. Have you prepared an exhibit explaining the mechanics of the New Eastside Resource Allocation Adjustment?

A. Yes. My Exhibit No. ___ (APB-12) shows the calculation of the New Eastside Resource Adjustment. As shown on that exhibit, the adjustment first removes the Net Plant amounts for the new Eastside resources that the Company allocates to Washington under the Revised Protocol. The adjustment removes Washington allocated Net Plant amounts of $6,086,324 for the Gadsby Peaker Project and $29,403,019 for Currant Creek. The adjustment also removes Annual Depreciation Expense amounts allocated to Washington of $263,559 for the Gadsby Peaker Project, and $1,049,645 for the Current Creek Project. The adjustment then removes $1,363,015 associated with the annual West Valley Lease from Washington's share of Rent Expense – Other Generation.

The overall Revenue Requirement effect of the New Eastside Resource Allocation Adjustment is presented in the testimony and exhibits of Mr. Schooley.

2. *Adjustment 5.5, Mid-Columbia Contract Allocation*

Q. What adjustment should be made to the Revised Protocol regarding the allocation of PacifiCorp's Mid-Columbia Contracts?

A. Washington's allocated share of Mid-Columbia Contract Embedded Cost Differential Benefit should be increased to reflect the appropriate treatment of these contracts for Washington. This treatment is consistent with the way the Revised Protocol treats Company-Owned Hydro.

Q. What is the basis for Staff's recommended Mid-Columbia Contract Allocation Adjustment?

A. As I described in detail earlier, the Revised Protocol allocates to Oregon 100% of PacifiCorp's Priest River contract and 75% of the Wanapum contract. The remaining Mid-Columbia contracts are allocated system-wide. For the reasons I gave earlier, PacifiCorp's allocation method is unfair and it is based in part on language in a contract that has expired. The cost and benefits of these resources should be allocated to the states in the former Pacific Power & Light territory, in the same manner as the Westside Owned Hydro generation.

Q. Have you prepared an exhibit explaining the mechanics of the Mid-Columbia Contract Allocation Adjustment?

A. Yes. My Exhibit No. ___ (APB-13) shows the calculation of the Mid-Columbia Contract Allocation Adjustment. As shown on that exhibit, this adjustment reverses the Revised Protocol's allocation of the Embedded Cost Differential amount allocated by the Revised Protocol to each state using the MC Factor. Staff's adjustment replaces the MC Factor with the Divisional Generation – Pacific Factor, which is the same factor used in the Revised Protocol for the allocating the Company's Westside Owned Hydro.

This changes the allocation of the Embedded Cost Differential to Washington from approximately 12.5 percent to approximately 16.8 percent. This adjustment results in a Mid-C Contract Embedded Cost Differential allocated to Washington amount of $6,087,545, and reduces Washington's allocated share of Net Power Cost by $1,564,711, as compared to the Revised Protocol's methodology.

3. *Adjustment 5.6, Seasonal Contract Allocation*

Q. What adjustment should be made to the Revised Protocol regarding the allocation of Summer Peaking Contracts?

A. Washington's allocated share of Purchase Power Expense – Seasonal Contracts should be decreased to reflect the appropriate treatment of several new seasonal contracts that PacifiCorp acquired specifically to serve the Company's Eastern Control Area.

Q. What are the contracts that are involved in Staff's Seasonal Contract Allocation Adjustment, and how are they allocated under the Revised Protocol?

A. The Company has entered into several significant Seasonal Contracts that are included in its Net Power Cost Study, Exhibit No. ___ (PMW-3), Tab 5, at page 5.1.3. The delivery point for each of these contracts is the Company's Eastern Control Area, to meet the growing summer needs of Utah. The total annual cost of these contracts is approximately $31.2 million.

Under the Revised Protocol, the costs of these contracts are being allocated using the Seasonal System Generation Purchases Factor. This results in approximately 8.2 percent of the costs of these contracts being allocated to Washington, or $2,560,511.

Q. What is the basis for Staff's Seasonal Contract Allocation Adjustment?

A. The needs of Utah and the Eastern Control Area caused the Company to acquire these resources. The Company has provided no demonstration that Washington's seasonal requirements caused the Company to acquire these contracts, in whole or in part. Staff is unaware of any Company-issued Requests For Proposals that have addressed either the Company's need to meet summer peaking requirements of Washington (or the Western Control Area), or that would provide comparative avoided costs of meeting any summer peaking needs utilizing Westside resources.

Q. Have you prepared an exhibit explaining the Seasonal Contract Allocation Adjustment?

A. Yes. My Exhibit No. ___ (APB-14) shows the calculation of the Seasonal Contract Allocation Adjustment. The adjustment removes the costs associated with these contracts from Washington's allocated share of Net Power Expense under the Revised Protocol, which results in a reduction of Net Power Expense allocated to Washington of $2,560,511.

4. *Adjustment 5.7, QF Contract Allocation*

Q. What adjustment should be made to the Revised Protocol regarding the treatment of QF Contracts?

A. Washington's allocated share of Purchase Power Expense should be decreased to reflect the appropriate treatment of several Qualifying Facility contracts that were recently entered into by the Company.

Q. What QF contracts are involved in Staff's QF Contract Allocation Adjustment?

A. The QF contracts involves are the US Magnesium, Desert Power, Kennecott, and Tesoro QF contracts. Each facility is located in Utah.

Q. How does the Revised Protocol allocate these QF contracts?

A. The costs of these QF contracts are being treated as "New" QF contracts under the Revised Protocol. Accordingly, the Revised Protocol allocates QF costs on a system-wide basis. If it is somehow determined that the "new" QF costs exceed the costs the Company would have otherwise incurred in acquiring comparable resources to the state approving the contract, the difference is assigned situs. *Revised Protocol, Exhibit No. ___ (DLT-2) at 7.* No

Revised Protocol adjustment has been proposed by the Company related to these contracts.

Q. How does the Revised Protocol's treatment of "new" QF contracts compare to the treatment of other QF contracts?

A. The Revised Protocol calls other QF contracts "Existing" QF contracts. *See id. at 18 (definition of "Existing QF Contracts") and 20 (definition of "New QF Contracts").* For "Existing" QF contracts, the Revised Protocol applies an Embedded Cost Differential Adjustment that is assigned situs. For example, this adjustment results in a $1,226,477 assignment of "excess" costs to Washington related to a single existing "out-of-market" QF contract in this state.

This is significantly different from the Revised Protocol's treatment of "New" QF contracts. For example, the four recent Utah QF contracts I identified have a total annual cost of approximately $52.2 million. Each of these contracts has prices that exceed PacifiCorp's embedded costs. Nonetheless, PacifiCorp allocates these costs on a "rolled-in," system-wide basis, with no adjustment for "excess" costs. Consequently, Washington is allocated a share of the total costs of these contracts.

Q. Why does the Revised Protocol allocate to Washington and every other PacifiCorp state a share of these $52.2 million in "New" QF contracts from Utah, when any "Existing" QF contracts that are also priced above PacifiCorp's embedded costs are allocated to the state where the QF is located?

A. The answer is simple. The Revised Protocol's different treatment for "New" versus other QF contracts is based on the effective date of the contract. QF contracts entered into on or after May 21, 2004, are "New" QF contracts. *Exhibit No. ___ (DLT-2) at 18*. Because the effective dates of these Utah contracts are all after May 21, 2004, they are treated as "New" QF contracts and the costs are spread to all states.

Q. How does Staff's QF Contract Allocation Adjustment treat these QF contracts?

A. Staff's QF Contract Allocation Adjustment treats these contracts as "Existing" QF contracts, for purposes of this proceeding. As I mentioned, each of these contracts has prices that exceed PacifiCorp's embedded costs, which should result in the situs allocation of the "excess" of contract price over embedded costs, in the same manner as the Revised Protocol treats the Washington QF contract I previously described.

Q. Why is Staff's adjustment appropriate?

A. First, the treatment of QF contracts should not differ based on the date the contract was signed. Ideally, the situs treatment of QF contracts is the appropriate method to mitigate issues associated with the each state's administration of these contracts.

Second, from Washington's perspective, these contracts truly are "Existing QF Contracts" under the Revised Protocol because Washington has not yet accepted the Revised Protocol. The date of May 21, 2004, relates to the effective date of the Revised Protocol based on its acceptance by jurisdictions other than Washington.

Third, it is reasonable to treat these QF contracts as "Existing" QF contracts, and therefore applying an Embedded Cost Differential, because of the characteristics of the contracts themselves. A review of the Confidential Board presentation material submitted in the various Exhibits of Company witness Tallman, (Exhibit Nos. ___ (MRT-15C) and ___ (MRT-16C), clearly shows that these QF contracts have been acquired strategically for Utah.

Finally, it is interesting to note there is language within the power purchase agreement for one of these QF contracts that require Utah ratepayers to be responsible for any costs disallowed by another jurisdiction.

Exhibit No. ___ (MRT-16C) at 2. This also indicates that there should have been some consideration of "excess" under any allocation model.

Q. Have you prepared an exhibit explaining the mechanics of Staff's QF Contract Allocation Adjustment?

A. Yes. My Exhibit No. ___ (APB-15) shows the calculation of the QF Contract Allocation Adjustment. Staff's adjustment is aimed at treating the four "new" QF contracts the same as the existing contracts and only adjusts the costs allocated to Washington.

The average rate of the four Utah contracts is first compared to the embedded cost rate of all other generating resources. An embedded cost differential amount is then determined by applying the difference to the total generation from the QF contracts. To remove the effect of these excess cost QF contracts, the embedded cost differential amount is then credited back to Washington using the same factor as the costs were originally allocated.

This adjustment procedure only addresses a method for adjusting Washington's allocated share of the four contracts, and results in a $1,737,328 reduction in Net Power Expense for Washington.

5. A&G Allocator

Q. Please describe the A&G Allocator Adjustment.

A. This adjustment is based on Staff's analysis of the allocation factor PacifiCorp uses in the Revised Protocol to allocate Administrative and General Expenses. Mr. Schooley is responsible for this adjustment.

6. Other Potential Power Supply Adjustments

Q. Did Staff consider other power supply and transmission allocation related adjustments to the Revised Protocol?

A. Yes. Staff evaluated several other possible adjustments that would address our concerns related to the Revised Protocol's treatment of costs. These potential adjustments relate to such cost elements as: 1) The allocation of costs associated several new, large purchase power agreements PacifiCorp acquired to serve the Eastern Control Area, 2) The allocation of costs associated with significant new generating plant additions related to Eastside resources; and 3) The allocation of costs associated with those generating resources that have previously been addressed in a "Joint

Report," namely the Craig, Hayden, Cholla Unit 4, and Foote Creek Wind generating projects.

Q. Please describe the Company's new, large purchase power agreements.

A. In addition to addressing the acquisitions of the Gadsby Peaker Project, the West Valley Lease, Current Creek, and the various Utah new QF contracts, Mr. Tallman describes the Company's recent entering into of several other purchase power agreements. These include a long-term (20 year) agreement with Deseret Power Generation and Transmission for 100 MWs, separate agreements with Kennecott and US Magnesium for 163 MW of "generating credit," and 95 MW of non-spinning reserves, respectively. *Exhibit No. ___T (MRT-1T) at 27 -29.*

Q. Please explain Staff's concerns regarding these new, large purchase power agreements.

A. A review of the confidential Board presentation material contained in Exhibit Nos. ___ to ___ (MRT-17C, MRT-18C, and MRT-19C) shows that these resources were acquired to meet the needs of the Utah "Bubble." PacifiCorp has provided no demonstration that Washington loads caused the Company to acquire the power from these agreements or these resources are least cost for Washington, yet the Revised Protocol allocates to Washington a share of these projects.

However, in order to facilitate the determination of Washington rates for purposes of this proceeding, Staff proposes no adjustment related to the system-wide allocation of these contract costs. Staff expects that the long-term recovery of any related costs will be addressed in the development of the Simplified Control Area Model, or other allocation model the Commission supports that is not based on the system-wide, "rolling-in" of costs.

Q. Please describe the Company's significant new generating plant additions related to Eastside resources?

A. The Company has included several large pro forma rate base adjustments related to plant additions in both its East and West Control area. *See Exhibit No. ___ (PMW-3), Tab 8, pages 8.4 and 8.4.1.* For example, under the Revised Protocol, PacifiCorp is allocating to Washington a share of approximately $31 million in plant additions to the Huntington Generating Facility alone, as well as smaller additions to other Eastside resources. The issues are the same for these additions as with other Eastside resources, because they are all being allocated under the Revised Protocol on a system-wide, “rolled-in” basis.

Again, in order to facilitate the determination of Washington rates for purposes of this proceeding, Staff proposed no adjustment related to the system-wide allocation of these plant addition costs. Staff expects that the long-term recovery of any related costs will be addressed in the development of the Simplified Control Area Model, or other allocation model the Commission supports that is not based on the system-wide, “rolling-in” of costs.

Q. Please explain Staff’s concerns regarding the other Eastside resources?

A. The prudence of several Eastside resources has been an issue in the last two general rate cases, without resolution. These resources include the Craig, Hayden, Cholla Unit 4, and Foote Creek Wind generating projects. The well traveled “Joint Report” has been repeatedly cited by both the Company and Staff in support of various positions taken regarding the prudence of these resources. *Exhibit No. ___ (GND-8).*

According to the Joint Report, Staff has accepted the prudence of these resources from a system perspective. However, PacifiCorp has made no showing that these resources are prudent for use in determining Washington rates. Staff's testimony in this proceeding does not fully resolve the prudence issue related to these projects, either.

The development of a control area based allocation model, or other allocation model not based on the system-wide, "rolling-in" of costs, will resolve the need to determine the prudence of these resources. Until such models can be developed however, Staff's proposal is to develop Washington rates using the Revised Protocol, with the specific adjustments recommended above and summarized in my Exhibit No. ___ (APB-2). This includes the transitional compromise of including the costs associated with the Craig, Hayden, Cholla Unit 4, and Foote Creek Wind generating projects.

Nonetheless, Staff's proposal does fall short of recommending that these projects be accepted as being prudent for long-term recovery in Washington's rates. This is not a perfect solution, but it is better than putting Washington ratepayer permanently at risk for the recovery of these costs, pending Commission direction on the appropriate allocation methodology path.

Q. Is there an alternative solution to delaying the prudence issue regarding these projects?

A. Yes. An alternative solution, in the event the Company objects once again to the delay in a prudence decision, is to treat these resources similar to Staff's proposed treatment of the Gadsby Peaker Project, West Valley Lease, and Currant Creek Project. That is, either the fixed costs, or both the fixed and variable costs associated with these projects can be removed from Washington's allocated share of Net Plant (or rate base), Depreciation Expense, and Net Power Supply Expense. This treatment would result in a significant reduction in Washington's Revenue Requirement.

Q. Why does Staff recommend that the Company's operating expenses associated with the Gadsby Peaker Project, West Valley Lease, and Current Creek Project be included under the Staff's Amended Revised Protocol, yet the Staff adjusts out the resources PacifiCorp later acquired?

A. The most important factor is timing. As discussed earlier in my testimony, the recent needs of the Eastern Control Area caused PacifiCorp to acquire the Gadsby Peaker Project, West Valley Lease, and Currant Creek Project. These acquisitions occurred more recently, after the growing disparity in load growth between the Eastern and Western Control Areas was generally acknowledged; and after the Company's most recent IRP and RFP processes recognized diverging control area needs and transfer capabilities.

Staff's proposed treatment of these resources is a compromise pending the development of the appropriate long-term allocation model.

7. *Transmission-Related Allocation Adjustments*

Q. How does the Revised Protocol allocate PacifiCorp's transmission-related costs?

A. The Revised Protocol allocates costs associated with transmission assets and firm wheeling expenses to each state on a system-wide, rolled-in basis, as are non-firm wheeling expenses and revenues.

Q. How does Staff recommend the Commission address the issue of Transmission-related allocations under the Revised Protocol?

A. Staff recommends no adjustments to this Revised Protocol's transmission-related allocation methodology for purposes of this proceeding. Staff recommends the Commission only accept this position as a "place holder" pending further action on both the Regional Transmission Organization activities and the future development of a control area based allocation model, or other allocation model not based on the system-wide, "rolling-in" of costs.

Q. Are there outstanding issues in regard to the allocation of transmission-related assets and wheeling costs and revenues?

A. Yes. The Revised Protocol's system-wide, "rolled-in" allocation of these element results in the allocation of costs and benefits related to significant transmission assets that may have nothing to do with PacifiCorp serving Washington. At the same time, other States are in the same position.

For example, under the Revised Protocol, Washington picks up a share of PacifiCorp's costs to move power from the Desert Southwest and Four Corners of southern Utah to serve Utah, while Utah picks up a share of the costs to move energy from Western markets to serve Washington.

There is no relationship between what transmission assets are actually needed and used to serve Washington and what is ultimately allocated under the Revised Protocol. No flow based allocation methods have been examined, and no attempt has been made to tie cost allocations to the actual needs of States, or even control areas, for that matter.

The establishment of a working Regional Transmission Organization may clarify this relationship. In addition, Staff's proposal to use an Amended Revised Protocol methodology for this proceeding only, allows Staff to make further recommendations on the allocation of transmission related costs and benefits in the context of a control area based allocation model.

Q. Under cost causation principles, how might PacifiCorp's transmission-related costs be allocated?

A. An appropriate allocation of these costs should recognize the difference in service area characteristics. For example, Washington's load centers are relatively compact and near both generation and power markets. By contrast, much of Oregon's load is rural, spread out, and further away from generation. Significant amounts of PacifiCorp's transmission assets and wheeling costs are devoted solely to serving its Oregon load. With these characteristics, a "rolled-in" approach to overall transmission related costs may not be appropriate, even within the Western Control Area.

By not now accepting, for the long-term, the Revised Protocol's (or Staff's Amended Revised Protocol's) method for allocating transmission-related costs, the Commission would be free to consider other alternatives that would better reflect the way the Company's transmission system is planned, built, and utilized, as well as any ultimate outcomes from the RTO process.

B. Alternative to the Staff's Amended Revised Protocol

Q. If the Commission rejects both the Revised Protocol and the Staff's Amended Revised Protocol, what should the Commission do then?

A. If the Commission determines that PacifiCorp did not sustain its burden of proof in this case, the Commission could reject the tariffs, as filed. In doing so, the Commission should require the Company in subsequent rate cases to file tariffs based on revenue requirements using a cost allocation methodology <u>not</u> based on the system-wide, "rolling-in" of Company resources.

C. Other Power Supply Costs

Q. Is Staff proposing specific adjustments to the Company's Power Supply Cost in addition to the Staff's allocation-related adjustments you previously discussed?

A. No. A typical analysis of power supply costs in a general rate case would consist of a detailed review of each of the components making up the total power costs, both fixed and variable. This includes a review of resource characteristics, fuel prices, contract terms, levels of wholesale sales and purchases, and any other factors affecting net power supply.

This level of analysis was not carried out by Staff in this proceeding. The obvious emphasis by Staff in this proceeding has been on the inter-jurisdictional cost allocation issue. The resolution of allocation issues is fundamental to the analysis of Company costs, particularly power supply and transmission related costs. The appropriate allocation method sets the path, or context, in which these costs are evaluated. This is particularly important for those jurisdictions which have a relatively small proportion of the Company's overall load such as Washington. Early in this proceeding, Staff made the decision to focus its resources on allocation issues, in order to resolve these issues for the long-term and in the best interest of Washington.

Staff's allocation-related adjustments to power supply costs previously outlined results from the recommended transitional use of the Amended Revised Protocol in this proceeding only. This does not mean, however, that other specific adjustments to power supply costs proposed by other parties in this proceeding do not have merit. Staff will continue to analyze the Company's filing and support any adjustments proposed by others that are appropriate.

VII. OTHER POWER SUPPLY ISSUES

A. The Company's Power Cost Adjustment Mechanism ("PCAM") Proposal

Q. Please summarize the Company's PCAM proposal.

A. The Company is proposing a bookkeeping account which would track the difference between the levels of power costs authorized by the Commission and the "actual" level of power costs experienced by the Company. The Company would then file to recover, or refund, the account balance when a specified level is reached. The Company is proposing an earnings test to determine whether balances would actually be recovered or refunded.

One significant feature of the Company's proposal is that it tracks changes to virtually all net power supply components, including cost changes for fuel, wheeling, purchases power expenses and wholesale electricity and gas sales.

Q. Please summarize the support the Company offers for the PCAM.

A. The Company's support for its PCAM is spread among the testimonies of Mr. Furman, Mr. Widmer, Ms. Omohundro, and Mr. Duvall.

Mr. Furman details a number of benefits to the Company from implementing a PCAM, including reduced volatility for shareholders. *Exhibit No. ___T (DNF-1T) at 20-21.* Mr. Widmer provides a historical perspective of the Company's net power cost exposure and the details on how the amounts would be determined. *Exhibit No. ___T (MTW-1T) at 29-36.* Ms. Omohundro discusses how she believes the PCAM would benefit customers. *Exhibit No. ___T (CAO-1T) at 6-9.* Mr. Duvall describes how PCAM adjustments would be allocated to Washington under the Revised Protocol. *Exhibit No. ___T (GND-1T) at 27-29.*

Q. What are the problems with the Company's support for its PCAM proposal?

A. There are several problems. First, Mr. Widmer presents figures and tables designed to describe the Company's net power cost exposure. *See Exhibit No. ___T (MTW-1T) at 29 and Exhibit No. ___ (MTW-4).* However, the great majority the exposure relates to the Western Energy Crisis beginning in 2000; it does not relate to either "normal or more recent variations in power supply costs. Accordingly, the Company's reliance on Energy Crisis data clearly overstates the more relevant measure of the Company's exposure to net power cost variations.

Moreover, it is the volatility in costs that supports a PCAM, not the base level of power costs. While it is true the overall level of market prices has increased, the volatility in those prices has not stayed at Energy Crisis levels. Indeed, Mr. Widmer's Exhibit No. ___ (MTW-5) demonstrates that market price volatility has been relatively smooth since mid-2001, and does not reflect the volatility of the Energy Crisis years that provides much of the "exposure" claimed by the Company.

Moreover, other factors can contribute to the Company's net power cost exposure, which a power cost adjustment mechanism should not protect against. For example, while Mr. Widmer claims that the Company has been forced to: "bear a disproportionate share of net power costs incurred to serve retail customers," Exhibit No. ___T (PMW-1T) at 29, he neglects to address how the Company's participation in the wholesale market has exposed the Company to higher net power costs. The Company also fails to discuss how the unexpected load growth in Utah loads has exposed the Company to higher net power costs.

Even assuming the PCAM was otherwise justified, ratepayers should not be called upon to protect the Company from volatility caused by load growth in other jurisdictions or the Company's willing participation in potentially volatile wholesale markets.

Q. How should the Commission address the Company's claim that changes in power costs are not recovered in rates without a PCAM?

A. This claim is made by PacifiCorp through the testimony of Ms. Omohundro, who states: "At present, unanticipated changes in power costs are not generally recovered in rates since rates are based upon normal power costs and are not "trued up" to actual costs." *Exhibit No. ___T (CAO-1T) at 8.*

The Commission should reject this claim because it is misleading, and it reflects a general misunderstanding of the "normalization" process long used for ratemaking in Washington.

The "normalized" power supply amount determined in the Company's own case is not based on "normal" power costs in the sense Ms. Omohundro uses that term. Rather, the "normalized" power supply costs in rates represent a number of water year conditions, fuel price scenarios, and market price levels. This is an important distinction, because the "normalized" technique of determining net power costs has a built-in mechanism to capture most variations in power supply costs over the long-term.

Q. How does this "normalized" methodology bear on the issue of an appropriate PCAM?

A. A PCAM should only be designed to recover or refund significant, unexpected variations in power costs that clearly have not been included in the "normalization" process. A broader PCAM can be developed only if the traditional "normalization" process is not used.

Q. What is Staff's recommendation in regard to the Company's proposed PCAM?

A. Staff recommends the Commission reject the Company's proposed PCAM as filed. The implementation of the proposed PCAM is not in the best interest of Washington ratepayers in the context of either the Company's proposed Revised Protocol or Staff's Amended Revised Protocol costs allocation proposals.

Q. Why does Staff recommend the Commission reject the Company's proposed PCAM?

A. There are several basic reasons for rejecting the Company's PCAM proposal as filed. First and foremost is the fact that the Company's PCAM is based on the use of the Revised Protocol.

As explained by Mr. Duvall, the PCAM treats net power changes determined within the PCAM consistent with the various resource types identified in the Revised Protocol. *Exhibit No. ___T (GND-1T) at 27-29.* Outside of changes due to Hydro-Electric Resources, and Existing QF contracts, PCAM changes are allocated to the States on a system-wide. "rolled-in" basis. This results in Washington ratepayers being exposed to Eastern Control Area costs under the Company's proposed PCAM. As I testified earlier, this is simply not appropriate.

Q. If PacifiCorp's Revised Protocol and PCAM were approved, what sorts of power costs could Washington ratepayers be required to pay?

A. These costs can include: the effects of market price variations in the Desert Southwest and Four Corners market; increased gas prices for the Company's new large, gas-fired generating projects it acquired to serve the Utah bubble; coal price exposure for a significantly greater share of coal-fired generating resources; exposure to wholesale market transactions related to activities outside the Western Control Area; and even the immediate higher power costs to serve faster growing jurisdictions outside Washington, that may not be recovered in a timely manner through base rates.

Q. Would this add complexity to the process of evaluating how the PCAM works?

A. Very much so. Because the PCAM is so broad in scope, the shear number of Company resources, purchase and sales transactions, and wholesale market activities results in an almost insurmountable audit burden.

Q. Can you give examples of this complexity?

A. Yes. First, the Company's own example of how the PCAM would work highlights Staff's concern. *Exhibit No. ___ (MTW-7) at 1.* Taking the Company figures as they are, and ignoring the normal expected variations captured in the "normalization" process, this exhibit shows that only approximately $30.9 million of "excess" power costs (Company-owned Hydro-West) are clearly identified as Westside or Washington-related. *Id. at 1, line 16.*The Company categorizes the great majority of the cost variation, approximately $160.6 million, as "All Other." *Id., line 21.* This presents a significant audit challenge.

Another example relates to the Company's wholesale transactions. The Company is a major player in the wholesale markets throughout its entire system. The PCAM proposal contains no mechanisms for protecting Washington ratepayers from any speculative activities of the Company in the wholesale markets. Under the PCAM, the Company's long-term and short-term wholesale purchase and sales contracts are simply included in the mix of transactions used to determine actual costs. Staff anticipates the audit burden to protect Washington ratepayers will be significant.

Q. Is the PCAM's inclusion of power from Eastern Control Area resources a problem?

A. Yes. PacifiCorp's inclusion of Eastside resources in its PCAM presents real inequities. For example, the Westside benefits from a long-term, relatively fixed price gas supply contract for the Hermiston Generating Project. This contract was fundamental to the Commission's prudence determination of that project, because the Company was able to minimize its exposure to variable gas prices.

Under the PCAM and the Revised Protocol, Washington loses much of the benefit of this arrangement, because Washington becomes more exposed to the fuel prices related to the significant new Eastside resources the Company has acquired, such as the Gadsby Peaking Project, West Valley Lease, and Currant Creek Project, in addition to other new gas fired resources such as the Lake Side Project.

Q. Does the PCAM protect Washington ratepayers from the effects of load growth in other jurisdictions?

A. No. As stated earlier, the Company's proposed PCAM exposes Washington to the increased power supply costs resulting from load growth in other jurisdictions. The PCAM does not appear to match the inter-jurisdictional allocations used to determine base costs with the new load growth causing the increase in power costs. Rather, the PCAM effectively passes though increased power costs based on old allocations, which shifts new costs from faster growing states to slower growing States.

Q. Does the PCAM give the Company any incentives to minimize power costs subject to the PCAM?

A. No. In particular, the Company's PCAM contains no "deadbands." "Deadbands" help provide additional incentives to manage resources. They also provide an additional level of rate "smoothing" that has long been a fundamental feature in ratemaking. Finally, a "deadband" also provides a certain amount of "insurance" for new mechanisms that are developed to track a large number of costs.

Power cost adjustment mechanisms that are designed with the best intentions can contain unforeseen flaws. A "deadband" can protect both the Company and the ratepayers, allowing the mechanism to be adjusted to address such flaws.

Q. Are there any other problems with the PCAM proposed by PacifiCorp?

A. Yes. As I mentioned, the Company proposes an earnings test before the Company would recover any deferred power costs under the PCAM. An earnings test is inappropriate because it ties the recovery or refunds due to variations in net power costs to a wide variety of factors that may affect Company's earnings. A PCAM should be designed to send the price signal that variable power costs are increasing or decreasing. An earnings test can effectively mute that signal.

In addition, the administrative burden of evaluating the entire Company's operations as part of a power cost adjustment mechanism is not an efficient way to operate a mechanism of this type. A limited, focused, and efficient power cost adjustment mechanism would not require an earnings demonstration.

Q. Please summarize the basic elements of an appropriate power cost adjustment mechanism that might be adopted in the context of an allocation model that does not allocate power costs on a system-wide, "rolled-in" basis.

A. A mechanism would be developed that is limited, focused, and efficient to administer. Such a mechanism would only address the variability in costs not under the control of the Company and not being recovered in base rates. The mechanism should be balanced, that is, it would capture benefits as well as costs. The mechanism should provide incentives for the Company to continue to manage its resources in a prudent way. Finally, the mechanism would be adaptable, such that changes can be easily made to address issues that may arise after initial implementation.

Q. Does PacifiCorp's PCAM have any of these features?

A. No.

Q. Is Staff open to a future PCAM proposal that is consistent with its cost allocation model being advocated for the long-term?

A. Yes. A limited, focused, and simple to administer power cost adjustment mechanism can be developed consistent with a Simplified Control Area Model, or the other models discussed by Staff. A power cost adjustment mechanism is only appropriate when PacifiCorp's costs to serve Washington can be efficiently and reasonably tracked. Staff is willing to work with the Company to develop a power cost adjustment mechanism proposal that is consistent with the appropriate allocation model adopted for use in Washington.

B. Prudence of Resource Acquisitions

Q. Please summarize the issues in this proceeding in regard to the prudence of Company's resource acquisitions.

A. The Company is continuing to seek a determination of prudence and the recovery, in Washington rates, of costs associated with certain generating resources and other resources it has acquired since its last contested rate case in 1986.

The Settlement Agreement approved by the Commission in Docket No. UE-032065 accepted the prudence of the Hermiston and James River generating facilities (both Western Control Area resources) for purposes of serving Washington customers. The Settlement Agreement anticipated that the Company's additional Eastern Control resources, West Valley Lease, Gadsby Peaker Project, Craig, Hayden, Foote Creek, and Cholla, would be examined in the subsequent proceeding, if and when it is determined that the inter-jurisdictional cost allocation methodology requires their prudence to be evaluated for purposes of setting Washington rates.

In addition to these resources, there is also a prudence issue for another large resource located in the Company's Eastern Control Area and acquired for purposes of serving Utah needs – the Currant Creek Project, as well as a number of other acquisitions identified by Mr. Tallman in his testimony. These other Company acquisitions consist of several purchased power agreements with wind farms, two long-term purchase power agreements with Utah Qualifying Facilities, a long-term purchase power agreement with Deseret Generation and Transmission Cooperative, and two generation-related agreements.

Q. Please summarize the Company's general position regarding the prudence of resource acquisitions for the purposes of setting Washington rates.

A. The Company's position is that prudence for these acquisitions and/or agreements should be based only on a total Company basis, not on the basis of a single state, such as Washington. *See, e.g., Direct Testimony of Mr. Duvall, Exhibit No. ___T (GND-1T) at 32.*

Q. Is the Company's "Company-wide" prudence theory valid?

A. No.

Q. Can a resource be prudently acquired on a "Company-wide" basis and not be considered prudent for Washington operations?

A. Yes. For example, it may be perfectly prudent for a utility to acquire resources to meet the incremental requirements of one specific jurisdiction or control area. This does not mean that it is then necessarily appropriate to "roll-in" those costs and recover them, in whole or in part, from all other jurisdictions. Cost recovery should follow cost causation. It is not necessary for the Commission to decide the prudence of a resource whose allocation is questionable for purposes of setting Washington rates.

Another possible reason for a state to analyze prudence issues differently than another state is when the Company acquires a resource to meet specific economic development goals of one state. For example, one state may favor one generation type over another to meet load growth. From that state's perspective, it may be prudent (and perhaps required) that the utility acquire the favored type of resource. However, that resource may not meet the prudence standards of another state that does not favor that type of resource.

Finally, a utility may acquire a resource for purposes of expanding its wholesale market transactions. One state may accept recovery of such costs if it finds the utility was prudent to assume the risks inherent in such a purchase. Another state, however, may decide it is not prudent for the utility to assume those risks. Of course, a state making that decision should not reap any benefits the utility may realize from such a resource.

In sum, the Company needs to make an "affirmative showing" in which it demonstrates the prudence of the resource for Washington. That is what the Commission said in its Third Supplemental Order in Docket No. UE-991832, as the Company acknowledges on page 20 of Mr. Duvall's direct testimony, Exhibit No. ___T (GND-1T).

Q. What is an "affirmative showing" of prudence?

A. An "affirmative showing" is exactly that: the Company must show the resource is needed, and used and useful for purposes of serving Washington. The bottom line is that it is not appropriate to limiting the prudence analysis to a Company wide basis only.

Q. Is there other language from the Commission's Third Supplemental Order in Docket No. UE-991832 that supports Staff's position?

A. Yes. Interestingly, the same Order language that the Company attempts to use to support its "Company-wide" prudence theory, actually supports Staff's Position. *See Exhibit No. ___T (GND-1T) at 31.* In that Order, the Commission re-iterates language from a previous order that states: "As the

Company provides electric service to customers in six states, including Washington, the Company's "joint facilities" must be allocated to each of the states."

Simply put, a resource does not become a "joint facility" simply because it is acquired by the Company. Logically, in order to be considered a "joint facility," there must be some affirmative showing that the facility is needed and used and useful to each of the states. The Company should not presume that the facility costs should be allocated to everyone, simply because it was acquired.

Q. How should the Commission resolve the issue of whether the Staff's or Company's prudence analysis applies?

A. The Commission should reject the Company's claims of prudence based on a Company-wide, total system approach. The Commission should reaffirm that the "affirmative showing" necessary for the Company to demonstrate prudence includes a specific showing of need in this state, a specific showing that the resource can actually serve Washington customers (or that it provides quantifiable benefits in relation to costs), and a specific showing that the resource is the least cost option for Washington.

Q. Mr. Duvall states that judging prudence of new resources from a State-specific basis is a new and higher standard than has been required in the past and therefore not appropriate. ***Exhibit No. ___T (GND-1T) at 36.*** **Is he correct?**

A. No. The prudence analysis recommended by Staff is neither a "new" or a "higher" standard. Staff's emphasis on what the Company calls a "state-specific" showing is nothing more than a reaction to the Company's and other jurisdictions' attempts to force an unprincipled and inappropriate allocation method on Washington customers. Any such "state specific" emphasis is justified by the fact that PacifiCorp is seeking to include in rates millions of dollars of costs associated with resources it has acquired to serve the needs of its Eastern Control Area.

Continued transmission constraints across the Company's system, coupled with the Company's highly diverse load growth characteristics between control areas and differences in regulatory environments among the states, make it essential that the Company demonstrate that its acquisitions are prudent from a Washington perspective, before the Company can expect to recover these costs on a long-term basis or through a PCAM.

Indeed, one of the most troublesome factors for Staff in this case is the Company's continuing claim that no showing of any kind is needed under the Revised Protocol before millions of dollars of costs are allocated to Washington customers. *See, e.g., Direct Testimony of Mr. Duvall, Exhibit No. ___T (GND-1T) at 36.* Staff strongly disagrees with this viewpoint.

Strangely, the Company makes a similar claim that, because the Revised Protocol has been adopted in other jurisdictions, the resources have been found to be reasonable in cost, and necessary to serve customers, including those in Washington. *Id. at 37.* This claim obviously lacks merit. The fact that another state commission may have accepted the Revised Protocol does not dictate what this Commission can or cannot do, nor does it change the Company's obligation in this state to prove the prudence of its resource acquisitions.

Q. What are Staff's recommendations relating to the new resource acquisitions the subject of this proceeding?

A. Consistent with Staff's overall allocation proposal in this proceeding, Staff recommends that the Commission take no action regarding the prudence of the subject resource acquisitions and agreements at this time. When an allocation model is developed for Washington that is not based on a system-wide, "rolled-in" allocation of resource costs, many of the resources at issue will not be included, and the prudence issues for those resources will not be presented.

C. Hydro Deferral Petition

Q. Please provide a general description of the Company's Hydro Deferral Petition.

A. In March 2005, PacifiCorp filed a Petition for an Order Approving Deferral of Costs Related to Declining Hydro Generation (Petition or Hydro Deferral Petition). The Commission assigned the matter Docket No. UE-050412. By its Order No. 2, dated June 8, 2005, the Commission consolidated the Petition, Docket No. UE-050412, with the Rate Case, Docket No. UE-050684.

In the Petition, PacifiCorp seeks Commission approval for the Company to defer certain "excess" power costs in order to track and preserve them for later recovery from ratepayers. It is my understanding that a utility cannot recover costs it incurred in past periods without deferred accounting approval by the Commission.

The Petition is the Company's attempt to address a recent trend of low hydro generation due to drought conditions; conditions that resulted in the declaration of a statewide drought emergency by the Governor of Washington.

The Company's Petition requests that the deferral continue through the conclusion of this general rate proceeding, because the Company anticipates that the PCAM or some other mechanism will be adopted that addresses the variability in power costs due to hydro conditions. *Hydro Deferral Petition at 1-2.*

The Company has been providing monthly updates to its 2005 forecast of deferrals related to the Petition.

Q. What is the basis for the Company's request for deferred accounting authorization?

A. According to the Petition, the Company believes that the financial impact from the low hydro trend warrants the use of deferred accounting. The Company claims that the normalization method used to determine net power cost for purposes of rates, does not provide for sufficient recovery of costs when there is a trend of low hydro. *Hydro Deferral Petition at 4-5.* The Company also claims that the tracking of actual hydro generation costs would better match the costs and benefits of the actual hydro generation. *Id. at 5.*

The Company cites several examples where the Commission has permitted deferred accounting, as well as previous Staff testimony in which a mechanism to recover excess power costs from extreme water conditions was discussed. *Id. at 6.*

Q. How did Staff approach its analysis of the Company's Hydro Deferral Petition?

A. Staff analyzed three issues related to the Company's request: 1) The extent of the drought on water conditions and generation from Company owned or contracted hydro resources; 2) The Company's method of calculating excess power costs due to extreme hydro conditions; and 3) Whether those costs should be recoverable by the Company.

The Company's monthly updates have provided the basic data necessary to review the Company's actual and estimated monthly deferral amounts through year-end 2005.

Q. Is there evidence of highly adverse water conditions during 2004 and 2005?

A. Yes. The snow pack and water content was significantly less than normal in much of the Northwest this last winter, particularly in the central Cascades, where much of the Company-owned hydro generation is located.

Q. Have you prepared an exhibit that identifies the impact of the reduced snow pack and water content on PacifiCorp's hydro resources?

A. Yes. Pages 1 and 2 of my Exhibit No. ___ (APB-16) contain information regarding the relative snow pack and water contact for the winter of 2004/2005. Page 3 of the Exhibit contains the Company's latest available deferral estimate based on actual hydro generation through August, and the Company's forecasted amounts for the remainder of 2005. PacifiCorp shows the updated total company deferral estimate as $40,086,311 (including deferrals associated with Eastside hydro), with Washington's share at $6,100,768.

Page 4 of the Exhibit shows the percent of actual and forecast generation for Company-owned hydro resources located in the Western Control area, and the Mid-Columbia resources, compared to normalized hydro generation.

Page 4 of the Exhibit also shows the generation "deficit" is not as great as one might have expected, based on the end-of-winter snow pack and water content data. As the percentage lines show, the actual generation for Company-owned Western Control Area hydro resources ranged from a low 44 percent of normalized generation in March 2004, to a surprising 106 percent just two months later in May.

Mid-Columbia generation was even less affected by the drought. Generation from these facilities ranged from 75.07 percent of normalized in April 2005, to virtually normal amounts for August through October 2005.

Q. Did you analyze why the actual generation from the Company-owned hydro in the Western Control Area and the Company's Mid-Columbia Contracts did not differ from normalized amounts as much as could be expected, based on the snow pack and water content data?

A. No. However, based on my experience, I have found that actual generation from hydro projects in the Northwest can be significantly affected by factors such as the timing of the snow pack melt, the amount of storage available, the extent that "spill" can be captured for generation, and the amount and timing of Spring and Summer rains.

In addition, the generation from Mid-Columbia projects is greatly affected by the availability of storage in the upper Canadian Columbia River basin, as well as the snow pack in that region, which was not as deficient as in other areas further south. However, even given these factors, it is clear that generation from the Company's hydro resources was affected by the Northwest drought in 2005 to an extraordinary degree. This suggests that some form of deferred accounting consideration may be appropriate.

Q. Did you analyze the Company-owned hydro generation located in the Eastern Control Area?

A. No. Washington should not be directly affected by changes, favorable or unfavorable, related to the Company's hydro resources located in Eastern Control Area.

Q. How does the Company calculate the deferred costs?

A. The Company proposes to track the cost of generation from all Company-owned hydro facilities, plus the hydro from the Company's Mid-Columbia contracts. The Company-owned hydro includes hydro facilities located in both the Eastern Control Area and the Western Control Area.

The Company calculates the difference between those costs and the costs of the same generation that the Company asserts was included in rates from the Company's last general rate case. *Petition at 10.* The Company multiplies the total difference by a weighted replacement power price to estimate the additional cost or benefit from changes in water conditions for the period. Washington is then allocated its share of costs or benefits based on the different allocation factors used in the Revised Protocol. *Id.*

1. Adjustment 5.8, Hydro Deferral Recovery

Q. Is the Company's calculation of deferred power costs appropriate?

A. No. Staff recognizes that the Company's procedure is not rigorous and is meant to only estimate the costs or benefits related to hydro generation variations, prior to the development of a more rigorous power cost adjustment mechanism.

However, three changes to the Company's procedure should be made before any recovery of deferred costs are considered. These changes include: 1) the effects of Eastside hydro generation should be removed; 2) there must be some consideration for the variances in water conditions, and resulting hydro generation, which is already included in rates through the normalization process; and 3) the allocation of any costs or benefits should be consistent with the cost allocation methods proposed by Staff in this case.

Q. Have you prepared an exhibit that gives effect to these adjustments?

A. Yes. My Exhibit No. ___ (APB-17) shows the effect of these three adjustments. First, the Company's calculations associated with the Eastside hydro resources are removed (lines 1-9). Second, a 15% "band" is implemented for each of the remaining two resource categories (Company-owned West and Mid-Columbia) (lines 10-12). This band represents a simple estimate of the variations in hydro generation that are already included in determining rates using the normalization process. Third, the "band" is then subtracted from the difference between actual and normalized generation and that result is then multiplied by a weighted average replacement energy price (lines 13-22) to derive the "excess" costs to be potentially deferred. Finally, the potential deferred costs are allocated to Washington based on the allocation factors Staff recommends in this case (lines 26-28). The total Washington deferred hydro costs are $2,103,823 ("Total" column, line 28).

All other procedures used by the Company are the same as those used in my exhibit, including the Company's price weighting calculation and the Company's use of forecasted generation for the September through December period.

Q. Why is the "band" appropriate?

A. The "band" focuses the Company's recovery of "excess" costs or benefits only to those cost variations that are "extreme," and otherwise not included in the rate making process. This is consistent with Staff's proposed methodology from the Company's previous rate case, Docket No. UE-032065, which the Company cites on page 6 of its Petition.

In that previous rate case, Staff proposed a hydro normalization method which excluded "more extreme stream flow conditions." The Staff anticipated the Company would make a separate filing to establish a mechanism to recover the effects of the more extreme conditions, should they occur. Indeed, the Settlement Agreement approved by the Commission in Docket No. UE-032065 adopted such a hydro normalization adjustment. The adjustment was determined by using only those years with water conditions within one standard deviation, plus or minus, from the mean conditions. Thus, rates were developed using a narrower band of water year conditions.

Staff's plus or minus 15 percent generation variance "band" proposed here is conservative compared to the approximate two-thirds (plus or minus 33 percent) of variation in water conditions captured by the normalization process accepted by the Company in the Settlement Agreement.

Q. Is the plus or minus 15 percent "band" conservative in the Company's favor or the ratepayers' favor?

A. It is conservative in the Company's favor because it reflects the fact that actual generation does not exactly follow water year conditions, as discussed earlier in my testimony.

Q. What is Washington's share of the "excess" costs determined by using Staff's methodology for calculating potential deferrals related to declining hydro generation?

A. Washington's share of the "excess" costs using Staff's methodology amounts to $2,103,823 for the period March 2005 through December 2005. This figure is shown on line 28 of Exhibit No. ___ (APB-17).

Staff recognizes this amount includes several months of forecasted generation through 2005. If Staff applied its methodology to the generation that will actually occur in these months, the "excess" amount would no doubt change. However, for purposes of this proceeding, Staff recommends the amount be set based on the Company's September update to the actual and forecasted generation contained in my Exhibit No. ___ (APB-17). This not only recognizes that residual effects on generation from the 2004/2005 winter drought will likely continue at some level into the Fall of 2005, but also the fact that Staff's methodology, although fully supported, results in "excess" costs significantly lower than the Company's proposed methodology.

Q. Should the Commission allow the Company to recover the $2.1 million in deferred "excess" power costs?

A. Yes. The Commission should allow the recovery of this fixed, one-time amount due to extraordinary drought conditions. The Commission should not allow the Company to continue to defer costs past year-end 2005.

Q. How should the fixed, one-time amount be recovered in rates?

A. The one-time amount of $2,103,823 should be amortized over a three year period, with the appropriate carrying charges, beginning with the April 2006 rate year. Staff witness Mr. Schooley describes the revenue requirement effect of this adjustment.

Recognizing the fixed, one-time only nature of this specific amount and the three-year timeframe of the amortization, Staff recommends that the Commission order the Company to incrementally increase its expenditures associated with public purpose programs in Washington at a rate equal to the annual amortized amount of this adjustment beginning in April 2009, or such time that the amount is fully amortized, if the Company has not filed a new general rate case by that time.

Q. Why should the Commission not allow PacifiCorp to continue to defer so-called "excess" power costs as requested in its Petition?

A. First, the Company should not be allowed to defer future excess power costs until an appropriate power cost adjustment mechanism can be developed, consistent with a Commission-approved Washington allocation method, *i.e.*, an allocation method not based on a system-wide, "rolled-in" allocation of resource costs.

Second, the deferral of power costs should be allowed for extreme conditions only. The Company has provided no evidence that drought conditions will exist in the Northwest during the winter of 2005-06.

Third, the Company's power supply expense proposal in this proceeding does not use a narrower distribution of water conditions for determining normalized power supply costs. A deferral mechanism such as proposed by the Company should only be considered when the Company also uses a more limited water condition distribution to develop normalized base rates.

Finally, Staff's Amended Revised Protocol, as a matter of compromise in this proceeding only, already results in significant power costs related to existing Eastside resources being allocated to Washington. It would be inappropriate to further burden Washington ratepayers with additional costs due to variations in hydro generation, when they are also picking up the costs associated with Eastside resources.

Q. Does this complete your testimony?

A. Yes.