Q. Please state your name, business address and position with PacifiCorp ("the Company.")

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah Street, Suite 300, Portland, Oregon 97232. I am employed by PacifiCorp as Managing Director, Planning and Major Projects.

Qualifications

Q. Please summarize your education and business experience.

A. I received a degree from University of Washington in Mathematics in 1976 and an MBA from University of Portland in 1979. I was employed by Pacific Power in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. Since my return to Portland, I have been involved in direct access issues in Oregon and have been responsible for directing the analytical effort for the Multi-State Process ("MSP").

Q. Have you previously testified in state regulatory proceedings?

A. Yes. I have testified in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming on net power costs, customer class cost of service, avoided costs and direct access. I also sponsored testimony in the Company's Structural Realignment Proposal ("SRP") and MSP applications.

Purpose

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony addresses inter-jurisdictional cost allocation, the allocation of power cost variances under the Company's proposed Power Cost Adjustment Mechanism ("PCAM"), and the prudence for Washington ratemaking purposes of the Company's resource acquisitions of Craig, Hayden, Cholla 4, Foote Creek, West Valley, Gadsby and Currant Creek generating units.

With regard to inter-jurisdictional allocation, my direct testimony first provides background information on PacifiCorp's system operations and associated modeling tools. Next, my direct testimony describes the "Dynamic" and "Hybrid" proposals and summarizes key analytical findings with respect to them. Finally, my direct testimony provides further explanation of certain provisions of the PacifiCorp Inter-Jurisdictional Cost Allocation Protocol ("Revised Protocol") sponsored by Mr. Taylor that relate to system operations.

In the portion of my testimony supporting the Company's PCAM proposal, I describe how net power cost variances are allocated to Washington under the PCAM, consistent with the Revised Protocol.

Finally, in addressing the prudence for Washington ratemaking purposes of the Company's resource acquisitions, I demonstrate that each of these resources are used and useful in providing service to the Company's Washington customers and should be included in the Company's Washington rate base consistent with the allocation of the costs of these resources under the Revised Protocol.

In the interest of clarity and consistency, when I use a capitalized term in my testimony, and do not otherwise define it, I intend the term to have the same meaning as provided for in Appendix A to the Revised Protocol. Appendix A is included as part of Mr. Taylor's Exhibit No.__(DLT-2).

Inter-Jurisdictional Cost Allocation

The PacifiCorp System

Q. What is the relevance of PacifiCorp's system operations to inter-jurisdictional cost allocation issues?

A. Most MSP participants expressed the view that cost allocations should reflect principles of cost causation. This is a relatively easy principle to follow for the assignment of distribution costs associated with local delivery of power to individual customers, but becomes more complex when it comes to transmission and generation costs. The local distribution costs in any State are dependent only on the customers in that State. Transmission and Generation costs, however, are costs incurred to produce and move bulk power to the local points of distribution across PacifiCorp's entire system. The Company has 1.5 million customers spread across six States covering over 135,000 square miles. The Company's supply portfolio consists of 8,200 megawatts of generating capacity from over 70 generating facilities located across eight states as well as many wholesale purchased power contracts with other utilities. The Company owns 15,000 miles of transmission lines, has over 125 points of interconnection with other utilities and has many wheeling contracts that in combination are used to transport the power produced at the various facilities to the loads across the system. The Company is limited by transmission constraints and operates its system on an integrated basis with two control areas. 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.

Q. Please describe how PacifiCorp operates its power system.

A. The Company dispatches its power system to minimize total Company costs on a six-state integrated basis. While the operation is separated into two control areas, it is dispatched as a single system from a central location. The Eastern Control Area includes the Idaho, Utah and Wyoming loads and includes generating resources such as Hunter, Huntington, Naughton, Gadsby, West Valley, Currant Creek, Dave Johnston, Cholla and Wyodak. The Western Control Area includes the California, Oregon and Washington loads and includes generating resources such as the Hydro-Electric Resources, Hermiston, Colstrip, and Jim Bridger as well as the Bonneville Peak Purchase contract and the Mid-Columbia Hydro Contracts.

Q. What are the primary responsibilities of a control area operator?

A. Each control area operator is responsible for ensuring that reliable service is provided to the control area loads in accordance with the National Electricity Reliability Council ("NERC") Minimum Operating Reliability Code. This is accomplished by making sure that adequate spinning and non-spinning reserves are available for unplanned generator outages and that adequate regulating margins are available to ensure that the system frequency remains steady as loads increase and decrease on an instantaneous, real-time basis.

Q. Why does PacifiCorp operate two control areas instead of one?

A. It would not be practical for the Company to operate as a single control area because of the limited transmission rights between its Western and Eastern Control Areas. While it may be technically feasible to do so, it would require the Company to go through a NERC control area certification process that would require consultation with neighboring control area operators. In addition, the Company would continue to operate its system in the same manner as it does today even if certified as a single control area.

Q. How does PacifiCorp model the transfer capability between its two control areas?

A. Exhibit No.___(GND-2) shows the transmission topology used in the Generation and Regulation Initiatives Decision Tools ("GRID") model. The "bubbles" labeled "4C," "APS transmission," "Cholla," "Colorado," "East Main," "Glen Canyon - Pinnacle Peak," "PV," "SP15," "Tri-State multi-point" and "Wyoming" are in the Eastern Control Area, while those labeled "Amps Colstrip," "BPA Multi-point," "COB," "Jim Bridger," "IPC transmission," "Mid Columbia," "West Main," and "Yakima WW" are in the Western Control Area. The maximum transfer capability modeled from the east to the west is 546 megawatts. This consists of 350 megawatts from Wyoming to Jim Bridger, 104 megawatts from East Main to Jim Bridger, and 92 megawatts from East Main to Amps Colstrip. The maximum transfer capability modeled from the west to the east is 1,171 megawatts. This consists of 400 megawatts from Jim Bridger to Wyoming, 254 megawatts firm and 441 megawatts day-ahead firm from IPC transmission to

East Main, and 76 megawatts from Amps Colstrip to East Main. In addition, 100 megawatts of transfer capability is reserved from west to east for non-spinning reserves and 100 megawatts is reserved from west to east for spinning reserves.

Q. How does the Company use its transfer capability between control areas?

A. 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.

Q. Does the Company use day ahead firm transmission to augment the integration of its control areas?

A. Yes. The Company is able to purchase day ahead firm transmission on an "as, if and when needed" basis to enhance system integration. Historically, this has represented about 441 average megawatts of transfer capability in excess of the Company's firm transmission rights. This allows the Company to use Resources in one control area to help meet the loads in the other control area.

Q. Does the Company expect to maintain two control areas in the event it participates in a Regional Transmission Organization ("RTO")?

A. No. An RTO would consolidate control areas in order to provide for system operation efficiencies, reliability benefits, improved planning and decision-making on system expansion and to provide "one stop shopping" for transmission services. The Company's Eastern and Western Control Areas, along with those of several other utilities, are expected to be consolidated into the same control area upon participation in an RTO.

Q. Can a Resource added in one control area provide benefits to customers located in the other control area?

A. Yes. The Company's control areas are not entirely separate, so power can be transferred directly from resources in one control area to the other control area. Even if power is not transferred directly, there are several ways that resources added in one control area can provide benefits to customers located in the other control area. This will be described later in my testimony in the section titled "Prudence of Resource Acquisitions." The degree to which resources in one control area can impact the other control area is shown in the analyses of the impacts of load loss, discussed later in my testimony in the sub-section titled "2003 MSP Analyses."

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 control area if that is the least-cost, least-risk option for the total system and for PacifiCorp's Washington customers.

Net Power Costs

Q. What are Net Power Costs?

A. Net Power Costs are the sum of: (a) the Company's variable generation costs (mostly fuel), (b) costs under purchased power contracts, and (c) wheeling costs, less (d) revenues received under power sales contracts.

Q. How does the Company compute Net Power Costs?

A. The Company computes Net Power Costs using the GRID model. This model was developed by PacifiCorp to simulate the hourly operations of its power and transmission system. GRID calculations reflect all of the Company's generating facilities and power contracts based upon their individual attributes. Operation of the Company's system is limited by transmission constraints. These constraints are also reflected in GRID. The Company has used the GRID model as the basis for computing Net Power Costs in rate cases filed since December 2001. The GRID model is more realistic than previous models of Net Power Costs because it simulates system operation on an hourly basis, substantially reflecting the way the system is actually operated.

<u>2002 MSP Analyses</u>

Q. Please describe the MSP analytical process during 2002.

A. Beginning in March 2002, the Company organized a Modeling Workgroup of MSP participants. The group received briefings on analytical methods and issues. The Company made available copies of the GRID model, together with computers capable of running it, to key groups in each State. Members of the workgroup were invited to suggest analytical studies that could be run either by the Company or by other participants.

The analytical workgroup met either by phone or in person 28 times during 2002. The workgroup discussed studies to be run, specific analytical issues, and the results of completed studies.

Q. What studies were considered by the workgroup?

A. The Company compiled a list of 56 studies which were proposed for consideration by the workgroup. Each study was intended to help evaluate the impact on revenue requirements in each State of specific changes in allocation methodology. As I indicated previously, the GRID model computes Net Power Costs on a total system basis. In order to calculate individual State impacts, the results of each GRID study were used as input into the Revenue Forecasting Model ("RFM"). Most studies were run for the 15-year period beginning with fiscal year 2004. The input data used in the first studies was updated four times to incorporate more recent information. The final set of data largely incorporates the results of the Company's 2003 Integrated Resource Plan along with hydro relicensing and clean air costs. Some studies were proposed, but not completed, either because the sponsor withdrew the request or replaced a requested study with another.

The 2002 studies identified and evaluated many issues and laid the foundation for development of the Protocol and the Revised Protocol. Studies MSP-1 (Rolled-In) and MSP-2 (Modified Accord) became the standards of comparison and were updated as the input data were updated. These studies allowed each MSP participant to assess the revenue requirement impact that different changes would have on their individual State. Studies MSP-8 through MSP-15 began the evaluation of directly assigning Resources to individual States and therefore introducing the concept of interchange and transfer pricing. This concept was eventually refined in Study MSP-47, which produced revenue requirement results using the Hybrid Proposal, which I describe later in my testimony. Studies MSP-16 and MSP-17 analyzed situs assignment of simple cycle and Hydro-Electric Resources, respectively. Studies MSP-31, MSP-33, and MSP-35 evaluated the inclusion of a hydro endowment in a dynamic framework. These studies also introduced the concept of monthly weighting of costs for Resources principally acquired for use during a particular season of the year. Both of these concepts were incorporated in the Revised Protocol. In addition, hourly allocation factors were examined in this series of studies along with the appropriateness of the situs assignment of Demand Side Management costs and the need for a wholesale jurisdiction. The use of hourly allocation factors did not prove to provide sufficient benefit over the use of monthly factors to take on the added complexity of working with hourly data. The studies on Demand Side Management resulted in validating that the current situs assignment method was still appropriate. Studies MSP-44 through MSP-52 examined the separation of States either physically or on an accounting basis. Studies MSP-47 (Hybrid), MSP-50 (Control Area Stand Alone) and MSP-51 (Divisional Stand Alone) were presented at the July 2003 MSP meeting.

<u>The Dynamic and Hybrid Proposals</u>

Q. The last MSP meeting of 2002 occurred in December. What were the results of that meeting?

A. The group identified two possible allocation methods: the Dynamic Proposal and the Hybrid Proposal. Under both methods, the Company would continue to operate its system on an integrated basis. Both methods were seen as "accounting solutions" that would pertain only to ratemaking. Nonetheless, the two methods represented quite different approaches. The Dynamic Proposal generally allocated a proportionate slice of all system-wide costs and revenues to each State, while the Hybrid Proposal assigned costs and revenues by control area with hourly accounting for transfers between control areas. Neither of these methods commanded a consensus of participants. Participants agreed that the Company should further analyze and develop the two proposals in consultation with other participants. The conclusions were to be presented at a future MSP meeting.

Following the meeting, the Company conferred with MSP participants and performed the requested analyses. The results were discussed at the MSP meeting in July 2003.

Q. Please summarize the Dynamic Proposal.

A. The core Dynamic Proposal is the "rolled-in" allocation method. Under this method, all States would pay shares of the Company's costs that are based upon the State's shares of total system demand, energy, and other factors. Cost shares would change over time as States grow at different rates and the characteristics of their loads change. Net Power Costs would be allocated based upon each State's requirement for system capacity and energy. Costs of generation Resources would be classified as 75 percent Demand/25 percent Energy-Related and allocated based upon the 12 CP Factor in the same manner proposed for System Resources under the Revised Protocol as described by Mr. Taylor. Under the Dynamic Proposal, the allocation of Resource costs would be the same for all generation, existing and new, regardless of location.

Q. What were the principal concerns raised by MSP participants regarding the Dynamic Proposal?

A. Some participants, primarily from Oregon and Washington, expressed concerns that using the Dynamic Proposal would cause customers in their States to pay additional costs associated with New Resources acquired to serve rapidly growing loads in Utah. Participants, again primarily from Oregon and Washington, expressed a belief that their States were entitled to a greater share of the benefits of the Company's Hydro-Electric Resources than would be provided under the Dynamic Proposal. There was also evidence that the Dynamic Proposal would not accommodate differing State policies and perspectives regarding the types of New Resources to be developed. The Company was also concerned that the Dynamic Proposal would not be sufficiently durable to resolve allocation issues during the years to come because of differing State policies and perspectives such as those related to New Resources additions and Direct Access Programs.

Q. Please summarize the Hybrid Proposal.

A. The Hybrid Proposal would separate PacifiCorp's system, for purposes of cost allocation, into two regions. Loads in the states of Oregon, Washington and California would be associated with the West Region. Loads in the states of Idaho, Utah and Wyoming area would be associated with the East Region. Generating Resources and Wholesale Contracts would be assigned based on present control area location. The overwhelming majority of Hydro-Electric Resources are located in the Western Control Area and would be assigned to the West Region. New Resources would be assigned to a particular region based upon location and would be substantively reviewed only by commissions in the affected region. Although the Company would continue to operate its system on an integrated basis, customers in the two regions would be deemed to be served from different Resource pools. Consequently, for ratemaking purposes, one region may be deemed to be "short" (having fewer Resources than needed to serve load) in an hour during which the other region is "long." To deal with this issue, the Hybrid Proposal includes an "interchange accounting" method which would compensate a "long" region if its Resources were deemed to have been relied upon by the other region.

Q. What were the principal concerns raised by MSP participants regarding the Hybrid Proposal?

A. Many parties expressed concerns and disagreements regarding the initial assignment of Resources to the regions. Even proponents of the Hybrid Proposal could not agree on an appropriate initial Resource assignment. Some parties advocated assignment of some Resources in ways that were inconsistent with the control area approach, based upon claims of historic "ownership." Some participants, primarily from Utah, expressed concerns that the Hybrid Proposal would lead the Company away from integrated least-cost system planning. They expressed concerns that the Hybrid Proposal would increase risks because it reduces the diversity of fuel types used to serve each region. They also expressed concerns that the interchange accounting method would complicate the regulatory process and become unworkable.

2003 MSP Analyses

Q. What were the results of the Company's analysis of the Hybrid and Dynamic Proposals?

A. The impact of the Hybrid Proposal on overall revenue requirements is shown in Exhibit No.___(GND-3). The overall impact is quite modest. On a present value basis, all States see small increases in revenue requirements as the existing allocation "hole" is closed. Each State's costs increase by less than one percent. All States see increases in some years and decreases in others.

Q. Did the Company analyze the risks associated with the Hybrid Proposal?

A. Yes. The Company's risk analyses are described in Exhibit No.___(GND-4). 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. The analyses considered 10 scenarios. The scenarios included two that studied the impact of temporary, unexpected losses of load: one in the East Region and one in the West. Four of the scenarios studied risks associated with Resources. Of these, one scenario altered assumptions regarding New Resource additions in response to changes in load forecasts since the development of the Company's 2002 Integrated Resource Plan. Two of the Resource scenarios looked at the impacts of low and high water conditions combined with high and low market prices, respectively. The fourth considered the loss, for one year, of a major coal-fired generating Resource in the Eastern Control Area. This last scenario also assumed that natural gas and market prices were high at the time of the loss.

The remaining four analyses studied risks associated with market prices. Of these, two assumed that wholesale market price trends (both natural gas and electric) were higher or lower than expected. Another looked at the impact of a year in which market prices in the West Region were higher, relative to the East Region, than were assumed in the base analysis. The last risk scenario studied the reverse of this situation, with East market prices rising relative to the West.

Q. What did the Company conclude from its analyses of generation risks?

A. The generation sensitivity studies show greater risk under the Hybrid Proposal than under the Dynamic Proposal. High water conditions, for example, reduce costs for the Company as a whole. Under the Dynamic Proposal, these cost reductions are shared equally among all States. Under the Hybrid Proposal, cost reductions are experienced only by States in the West Region. Patterns associated with generation loss in the East Region were even more striking. While the Dynamic Proposal results in similar cost increases for all States, the Hybrid Proposal leads to much greater cost increases in the East Region – nearly three times as great when measured against the Dynamic Proposal on a dollars-per-megawatt-hour basis. The Hybrid Proposal actually leads to cost decreases in the West Region, due to increased revenue from off-system sales and interchange accounting.

Q. What did the Company conclude from its analysis of market price risks?

A. Studies of market price risk also showed greater risks under the Hybrid Proposal than under the Dynamic Proposal. Low market prices decrease costs for the Company as a whole. This was true in eight of the 10 years that the Company analyzed. The opposite is true under high market prices. Net Power Costs increase with higher market prices when the Company buys more from the market than it sells. The only two years this was not true, 2008 and 2009, followed the addition of two low incremental cost resources on the system, creating a short-term surplus of power which resulted in lower power costs for the Company when market prices increased. Under the Dynamic Proposal, these cost increases and decreases are shared among the States in proportion to their retail loads. Under the Hybrid Proposal, States in the West Region experience a cost increase when total system costs decreased and received a cost decrease when total system costs increased. This pattern reflects the differences in the initial assignment of Resources as well as different load and Resource balances in each control area over the 10-year study time frame. The Western Control Area receives benefits under high market prices since it is generally surplus in relationship to the Eastern Control Area in the Hybrid analyses and therefore receives more revenue credit from system balancing sales and interchange accounting.

Q. How does the Revised Protocol correspond to the "Dynamic" and Hybrid" Proposals described above?

A. The Revised Protocol contains elements of both the Dynamic and Hybrid Proposals as well as some new concepts. No further work was done on either the Dynamic or Hybrid Proposals since the July 2003 meeting and neither proposal was ever completed as the Company focused its efforts on the Protocol and subsequently the Revised Protocol. In March 2005, the Company, along with other interested parties, began to address issues associated with the Hybrid

Proposal in response to the Oregon Commission's Order on MSP, Order No. 05-021 in Docket UM 1050. In that Order, the Oregon Commission adopted the Revised Protocol, and further required the Company to develop a Hybrid Method by December 1, 2005 that can be used as a comparator to the Revised Protocol for reporting purposes only.

<u>Consequences of Load Growth</u>

Q. One of the concerns expressed during the MSP is that not all States are growing at the same rate. Is this the case?

A. Yes. Exhibit No.___(GND-5) shows the change in both energy consumption and contribution to system peak over the last 10 years. As can be seen, Utah's load growth has been significantly higher than that of the other States. The Company's current load forecast expects this trend to continue.

Q. You testified that the Revised Protocol allocates costs dynamically and all States share in the cost of New Resources. Does this provision cause slow-growing States to subsidize fast-growing States?

A. Not to a material degree. At the time of its 2003 MSP filings, the Company reached this conclusion based on three analyses: an analysis of a specific New Resource addition, an examination of the impact of the Hybrid and Dynamic Proposals, and the analysis of load risks conducted on the Hybrid and Dynamic Proposals. These studies indicate that the Dynamic Proposal limits, to a surprising degree, the impacts of load growth across states. On balance, an allocation under the Dynamic Proposal limits the impacts of faster Utah load growth as well as the Hybrid Proposal.

Q. Please describe the Company's specific analysis of the impact of Utah load growth under the Dynamic Proposal.

A. In this study, Utah's loads were increased an additional 200 megawatts above the MSP forecast starting in 2010. Concurrently, a 200 megawatt combined-cycle gas plant was assumed to be added to meet the additional load. Exhibit No.___(GND-6) shows the revenue requirement impacts of these two changes. Utah is allocated 94 percent of the total revenue requirement increase. The other States experience some impact, but the impact is minimal.

Q. Why aren't more of the costs of the additional Resource passed on to other States?

A. While all States pick up their proportional share of the higher than system average costs of the New Resource, Utah – the faster growing State in this example – picks up a larger share of all other allocated costs. As a result of its now larger allocation factors, Utah picks up a larger share of the costs of the remaining generation Resources, a larger share of the system's transmission costs, a larger share of A&G expenses, and all other allocated costs.

Q. You indicated earlier that the Company conducted a risk analysis that studied the impact of a loss of load in each Control Area. What did the Company conclude from this analysis?

A. A one-year loss of load would allocate costs very similarly under the Hybrid Proposal and the Dynamic Proposal. The results are shown in Exhibit No.___(GND-4). As measured on a dollars per megawatt hour basis, a loss of load in one State increases costs in that State by an amount that is very similar between the two proposals. Interestingly, a loss of load in one State has almost no impact on costs in other States under either proposal.

Q. Would you expect this same pattern if loads increased?

A. Yes. Based on this study, I would expect an increase in loads in one State to reduce costs per megawatt hour in the affected State and have little effect on remaining States.

Q. Are there additional conclusions that can be drawn from this risk analysis?

A. Yes. The Company examined the response of individual generating resources predicted by GRID as a result of the loss of load. The results, presented in Exhibit No.___(GND-7), show clearly that the two control areas work together to meet changing loads. In response to load loss in the Eastern Control Area, Company generating resources reduced their output by 162 average megawatts. Of that reduction, nearly half (46 percent) occurred at Resources in the Western Control Area. A similar shared response occurs in response to load loss in the Western Control Area. The control areas are not totally isolated from one another. This implies two conclusions. First, there is no operational reason to assume that resources added in the Eastern Control Area have no benefit to the Western Control Area. Second, even the Hybrid Proposal would not be sufficient to entirely insulate a state in one control area from developments in another control area, because the operation of the system links the two.

Q. You stated above that at the time of the MSP 2003 filings, the Company had concluded that allocating the costs of New Resources dynamically among jurisdictions did not result in a "material" subsidy flowing from slower-growing States to faster growing States. Why did the Company continue to study the load growth issue after the 2003 filings of the original Protocol?

A. For two reasons. First, Oregon parties were not convinced that the analyses done before the Protocol filing were adequate to resolve the load growth issue. Second, the concept of "materiality" is somewhat subjective. Oregon parties pointed out that what appears to be a "small" cost shift, when expressed as a percentage of existing rates, can nonetheless translate into a significant impact when expressed in dollars. Because our Protocol filing did not resolve the load growth issue, parties in Oregon and Utah submitted a number of additional data requests which gave rise to a number of additional studies.

Q. Please describe the nature of these studies.

A. Most of the studies assumed either a one-time increase in Utah loads or a continuing pattern of higher Utah load growth which were matched with different types of Resource additions. Additional similar studies were done assuming higher Oregon load growth and corresponding Resource additions. Furthermore, two studies were done which attempted to quantify the cumulative impact of faster Utah load growth over a 14-year period. These studies (one performed in response to Oregon Public Utility Commission (OPUC) Staff Data Request 59/60, and the other performed subsequently in response to Committee of Consumer Services (CCS) Data Request 10.1), estimate and compare two different cost streams – one corresponding to low Utah load growth (equal to the average of the other States' projected load growth) and one corresponding to the higher rate of Utah load growth that is currently forecasted. For purposes of these studies, the difference between these cost streams is predictive of the impact on other States of the costs of Utah's additional relative load growth. The analysis performed in response to CCS Data Request 10.1 improved upon the OPUC studies by more closely matching New Resources to load growth. The improved study shows that the 14-year present value of cost shifts to Washington from Utah load growth is $22 million, or less than one percent of revenue requirements.

Q. What quantitative assumptions underlie these studies?

A. Major assumptions are as follows:

1. All studies use the Company's 2003 load forecast.

2. Additional Resources are layered on top of underlying load growth and planned IRP Resource additions.

3. All studies assume an underlying system peak Resource deficiency in the early years and the addition of Resources that closely match the Diversified Portfolio I from the Company's 2003 Integrated Resource Plan with two long-term purchased power contracts removed from the Western Control Area to reflect the lower loads forecast for the West in the Company's 2003 load forecast.

4. Most of the studies assume that future wholesale gas and electricity prices will follow the Company's forward price curves. Some of the studies were done with a high natural gas/electricity price assumption.

Q. Please summarize the results of these studies.

A. Under a rolled-in allocation method a faster-growing State supports both its allocated share of any New Resource additions and a larger share of the Company's existing costs. Correspondingly, slower growing States support their allocated share of the cost of the New Resource addition, but a smaller share of the Company's existing costs. In our studies, the sum of these two State revenue requirement impacts is compared to the total revenue requirement impact of the New Resource additions. If the total revenue requirement increase experienced by a faster-growing State is equal to or greater than the total revenue requirement impact of a Nw Resource, the faster growing State is deemed to be "supporting the cost of its load growth" and not causing a cost shift to slower growing States.

When considered from this perspective, our studies suggest that under the various approaches, a total system allocation method, as embodied in the Protocol and Revised Protocol, results in the growth State supporting between 86 percent and 127 percent of the cost of its load growth.

Q. Why do the percentages differ from study to study?

A. It appears that principal drivers of the study outcomes are:

1. The greater the rate of growth of one State compared to other States, the greater is the potential for cost shifts to slower growing States.

2. The higher the cost of New Resource additions compared to existing Resources, the greater is the potential for cost shifts to slower growing States.

3. The better New Resource additions are matched to load patterns through an effective IRP process, the lower is the potential for cost shifts to slower

States.

Q. Do these studies suggest that parties should ignore the potential for faster growing States shifting costs to slower growing States?

A. No. The studies indicate that there is a potential for some shifting of costs. As a general proposition, MSP participants seem to favor eliminating any potential cost shift, as long as that could be done in a relatively simple and understandable way without giving rise to other, undesirable unintended consequences.

Q. Are there other mitigating factors to consider?

A. Yes. When a State loses load unexpectedly, other States are allocated a greater share of the fixed and variable costs of all Resources. This helps to mitigate the impact on the remaining customers in the State that loses load who would otherwise bear a larger share of the fixed and variable costs.

In addition, the impact of Utah load growth is balanced by the expected Resource loss in western States. One of the underlying tenets of the Revised Protocol is that all States bear a rolled-in share of Resources that are acquired to replace Existing Resources. Existing Resources that will require replacement over the next several years include expiring long-term wholesale contracts (primarily on the West side of the system), plant retirements, and the lost generation from Hydro-Electric Resources and Mid-Columbia Contracts as a result of relicensing and contract renegotiation. For the States that are recipients of the “hydro endowment,” this means that other States are paying a share of the costs of replacing resources from which the hydro endowment States have benefited.

Q. Does the "embedded cost differential" method affect cost shifts?

A. Yes. It helps to mitigate them for Washington if New Resources cost more than existing ones, because the embedded cost of other Resources increases. The embedded cost differential (ECD) method compares Hydro-Electric Resource costs to the embedded cost of other Resources. If embedded costs grow due to load growth, the value of the hydro endowment increases in the Revised Protocol. In our studies that attempted to quantify the cumulative impact of faster Utah load growth over a 14-year period, the impact of the ECD is to reduce the impact of cost shifts to Washington customers due to load growth in Utah.

Q. Has an acceptable method of eliminating any potential for cost shifts from different rates of load growth been identified?

A. No. However, as described in the Revised Protocol, the Company and other parties have committed to further discussions and analysis of potential additional allocation mechanisms or structural changes that would better address the issue. A workgroup has begun work on this issue and the Company anticipates filing a report with the commissions, pursuant to Section IV E of the Revised Protocol, on October 20, 2005. Based upon the analysis completed to date, the Company has concluded that a rolled-in approach for the allocation of New Resource costs, as modified in the Revised Protocol, provides the best balance of reasonably assigning costs without unintended consequences.

Revised Protocol Provisions

Development of the MC Factor

Q. Please describe the MC factor.

A. Appendix F to the Revised Protocol contains a description of the calculation of the MC factor as well as example calculations of the factor. Appendix F is included as part of Mr. Taylor's Exhibit No. ___(DLT-2). The MC factor is used in the Revised Protocol to allocate the Mid-Columbia Adjustment among the States.

Q. Why has the Company developed an MC factor?

A. The Company performed an extensive review of the Mid-Columbia Contracts at the request of the MSP participants. There are four contracts that were entered into in the 1950's and 1960's, and three contracts that were entered into in 2001. These latter three contracts are successor contracts to the two earlier contracts with Grant County which provide the Company a share of the output of the Priest Rapids and Wanapum dams. The Priest Rapids contract stated that the output was for the benefit of Oregon customers and the Wanapum contract stated that the output was for the benefit of Oregon and Washington customers. Based on this language, the MC factor is developed as though the Priest Rapids energy is assigned to Oregon and the Wanapum energy is assigned to Oregon and Washington as described in Appendix F. The energy from the three successor contracts is assigned to Oregon during the time subsequent to the expiration of the Priest Rapids contract and prior to the expiration of the Wanapum contract. After both contracts have expired, the energy from the successor contracts is split between Oregon and Washington as described in Appendix F. In the MC factor, the energy from the remaining two contracts, associated with the Rocky Reach and Wells projects, is spread system-wide as these two contracts do not have specific language identifying any particular State as the beneficiary of the output. The MC factor is then calculated by dividing the energy assigned and allocated to each State by the total energy from the Mid-Columbia Contracts. The Mid-Columbia Adjustment is then made based on an allocated share of the costs of all of the Mid-Columbia Contracts using the MC factor. This adjustment ensures that no one State is burdened if the costs under one of the Mid-Columbia Contracts diverge from the other contracts. This method ensures that all States are afforded a share of the costs and benefits of the Mid-Columbia Contracts, with Oregon and Washington receiving a larger share than would be the case if they were treated as System Resources.

Seasonal Resources

Q. Mr. Taylor's direct testimony indicates that the allocation factors for Seasonal Resources use monthly factors that are weighted by the monthly portion of the total annual energy generated by the Seasonal Resource. On what basis are these energy values determined?

A. Seasonal Resources are primarily acquired to meet the Company's retail load; however, the GRID model will run Seasonal Resources to make wholesale sales if it reduces the overall system Net Power Costs. To isolate the operation of Seasonal Resources for meeting retail loads, a separate GRID run is made in which no incremental hourly sales are made in the wholesale markets. The monthly and annual energy values are taken from this study and provided to Mr. Taylor for purposes of calculating allocation factors for Seasonal Resources.

Allocation of PCAM Net Power Cost Variances

Q. From a jurisdictional allocation perspective, what principal did the Company follow in designing the proposed PCAM?

A. The primary principal was to ensure that the inter-jurisdictional cost allocation for the PCAM be consistent with the allocations under the Revised Protocol.

Q. Is the allocation of costs under the proposed PCAM consistent with the Revised Protocol?

A. Yes. Under the Revised Protocol, all costs are generally allocated under a rolled-in approach, subject to four exceptions. The first exception, Seasonal Resources, use monthly-weighted allocation factors, rather than annual allocation factors. While this is a departure from the strict application of a rolled-in methodology, the costs of Seasonal Resources are still allocated on a system-wide basis. The other three exceptions result from the application of the ECD to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.

Q. What effect does the ECD have on cost allocation?

A. First, the ECD allocates the costs and benefits of the Hydro-Electric Resources to the former Pacific Power and Light jurisdictions. Second, as compared to rolled-in, the ECD allocates a higher percentage of the costs and benefits of the Mid-Columbia Contracts to Oregon and Washington. Finally, the ECD allocates the costs and benefits of Existing QF Contracts on a situs basis.

Q. How does this affect the proposed PCAM?

A. The proposed PCAM is designed to allocate changes in costs and benefits for these three components in a manner that is consistent with the initial allocation of the costs and benefits under the Revised Protocol.

Q. How is this done?

A. As testified by Mr. Widmer, the GRID model is used to isolate all net power cost changes from the baseline forecast.

Q. How are the net power cost changes associated with Existing QF Contracts determined?

A. The actual costs for Existing QF Contracts in Washington are compared to the costs included in the GRID study used to set current rates. This amount is the PCAM-related adjustment for Existing QF Contracts.

Q. How is the PCAM-related adjustment for Hydro-Electric Resources allocated among the Company's jurisdictions?

A. This adjustment is allocated using the Divisional Generation Pacific (DGP) factor.

Q. How is the PCAM-related adjustment for the Mid-Columbia Contracts allocated among the Company's jurisdictions?

A. This adjustment is allocated using the Mid-Columbia (MC) factor.

Q. How is the PCAM-related adjustment for Existing QF Contracts allocated among the Company's jurisdictions?

A. This adjustment is assigned on a situs basis.

Q. How is the remaining PCAM adjustment amount determined?

A. The remaining PCAM-related changes in net power costs are determined by taking the difference between the adjusted actual and normalized net power costs less the amounts previously applied to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.

Q. How is the PCAM-related adjustment for all other resources allocated among the Company's jurisdictions?

A. The remaining PCAM adjustment is allocated on the System Generation (SG) factor.

Prudence of Resource Acquisitions

Q. What requirement was imposed on the Company regarding the prudence of certain resource acquisitions?

A. In the Commission's Third Supplemental Order in the Company's 1999 general rate case (Docket No. UE-991832), the Commission approved a stipulation that contained the following requirement:

> The Company will be required to make an affirmative showing in the direct testimony and exhibits of its next general rate proceeding demonstrating the prudence of those resources acquired since its previous general rate case (Cause No. U-86-02) which it proposes to include in rates in such proceeding.

Q. Have the resources acquired between the Company's 1986 and 1999 general rate cases undergone a prudence review process?

A. Yes. The participating parties in the Company's 1999 general rate case (Staff, Public Counsel, and ICNU) were provided an opportunity to review the information provided by the Company that would comprise the Company's direct case as it relates to the acquisition of resources between the Company's 1986 and 1999 general rate cases. This review culminated in the Joint Report, a copy of which was included in the Company's last general rate case (Docket No. UE-032065) and is also included as Exhibit No.___(GND-8) in this proceeding.

Q. Which resources were addressed in the Joint Report?

A. The Joint Report addressed Craig and Hayden, Cholla Unit 4, the James River cogeneration project, the Hermiston cogeneration project, and the Foote Creek Wind Project.

Q. What action did the Commission take on the prudence of these resources in the last general rate case?

A. The Commission found the two resources in the Company's Western Control Area (Hermiston and James River) to be prudent. (Order No. 06, Appendix A, Paragraph 10(c)). The prudence of the resources acquired since 1986 located in the Company's Eastern Control Area (West Valley, Gadsby, Craig, Hayden, Foote Creek, and Cholla) was not determined in that proceeding due to a lack of agreement on inter-jurisdictional cost allocation. The Joint Report did find, however, that Craig, Hayden, Foote Creek and Cholla were prudent on a system-wide basis.

Q. What was the conclusion of the Joint Report?

A. In the Joint Report, Staff concluded that the Company's acquisition of resources was consistent with increases in load and customer growth, and that the Company's decisions regarding the need to acquire new resources was guided by the Company's least-cost plan. Further, although Staff did not make a determination that the resources were acquired specifically to satisfy demand of Washington customers, Staff concluded that on a system-wide basis the resources were acquired prudently. Staff indicated that future proceedings could consider "whether these resources were acquired prudently to satisfy increased load growth or demand in Washington State, including consideration of the Company's commitments under merger agreements and orders, the impact of the 'inter-jurisdictional' allocation method used by the Company, and particular load-growth characteristics of the Company's Washington service territory." (Joint Report, p. 62)

Q. Has the Commission traditionally assessed the prudence and cost allocation of new resources from a system-wide or state-specific perspective?

A. It appears from prior decisions that the Commission has traditionally assessed prudence and cost allocation of new resources from a system-wide perspective. The jurisdictional allocation of total system costs across all states has been the consistent practice with respect to Washington's regulation of PacifiCorp and its predecessors for many years. That was the standard prior to the Pacific Power / Utah Power merger, that was the standard for post merger investments, and it should remain the standard now.

In its 1986 order in Cause No. U-86-02, the Company's last fully litigated general rate case in Washington, the Commission affirmed the appropriateness of sharing PacifiCorp's integrated system costs across all the states that PacifiCorp serves:

> As the Company provides electrical service to customers in six states including Washington, the Company's joint facilities must be allocated to each of the states. (Second Supplemental Order, Cause No. U-86-02, page 33)

Q. Why is it appropriate to review the prudence of the Company's resource acquisitions from a system-wide basis?

A. It makes sense to determine the prudence of resource acquisitions that support and benefit the Company's entire system from a system-wide basis. The Company operates a geographically dispersed system with characteristics that differ by location. In order to take advantage of those differences, the Company operates and plans its system on an integrated basis to capture the efficiencies of its system, which benefits all of the Company's customers by keeping net power costs as low as possible. Operating and planning the Company's system from the perspective of one State, in contrast, would lead to sub-optimal financial results for the Company and all of the Company's customers would pay higher costs. Accordingly, the prudence of the resource acquisitions should be analyzed from a total Company basis, not on the basis of a single State. Since the Joint Report found that resources were prudent from a system basis, the Commission has a sound basis for concluding that the acquisitions were prudent and therefore eligible for inclusion in Washington rates.

Q. How is the treatment of these resources affected by the "impact of the 'inter-jurisdictional' allocation used by the Company"?

A. The Company is proposing adoption of the Revised Protocol in this proceeding. These resources are proposed to be treated in the manner provided in the Revised Protocol. The Revised Protocol does not require that we demonstrate a "State-specific" benefit for particular resources before they can be recovered in a particular State's retail rates. Rather, resources are treated on a system-wide basis, and allocated among the States pursuant to the Revised Protocol, which in the case of some resources takes into account the seasonal nature of the resource and any seasonality of a State's load.

Q. What are the limitations of a State-specific approach to cost allocation and prudence reviews?

A. As discussed in the beginning of my testimony, in an integrated system like PacifiCorp's, it is not always clear which State is responsible for what costs. Costs related to production, transmission and Company overheads are not related to any specific load and, therefore, it is necessary to develop a method to apportion those costs among the States and customers served from the integrated system. In addition to not being able to identify which State is responsible for which cost, it is not always clear whether new resources are being added for load growth, replacement of expiring resources and contracts, or for system reserves. These factors make assigning cost responsibility of specific resources to specific States very subjective.

Q. Has it been the Commission's policy to require that each resource on the Company's system physically deliver power directly to Washington customers before that resource's costs can be included in the Company's Washington rates?

A. No. For example, in the Commission's order addressing the prudence of Colstrip 3, the Commission states:

> The Commission is aware that the plant is currently producing power, and, in fact, power from the plant was used to meet the company's power needs in December 1983. The Commission is aware that the current surplus may end in the not too distant future. The Commission has considered the

> power reserves of the company and is convinced that the Colstrip 3 plant is used and useful to the ratepayers of the state of Washington. (Second Supplemental Order, Cause No. U-83-57, page 8)
>
> Colstrip 3 is used. It now produces power and has been used to meet the company's power needs. Colstrip 3 is useful. It provides a source of reserves and is a relatively low-cost resource. (Second Supplemental Order, Cause No. U-83-57, page 9)

The order does not cite the need to physically move power to Washington loads in order for that resource to be used and useful. In fact, the Company does not have sufficient transmission rights to move all of the power from its share of Colstrip units 3 and 4 to its Washington loads.

Q. You previously stated that the Company is limited by transmission constraints and operates its system on an integrated basis with two control areas. Has the Commission previously taken into account the control area in which a resource is located in determining prudence?

A. No. Prior to the 1989 merger with Utah Power, the former Pacific Power operated as an integrated system with two control areas – a Western Control Area and a Wyoming Control Area. Many of the same transmission constraints for moving power between control areas that exist now existed then, yet the costs of the Dave Johnston and Wyodak generating stations were included in Washington rates even though these generating stations were in the Wyoming Control Area and Washington customer loads were in the Western Control Area. Dave Johnston and Wyodak together provide over 1000 megawatts of capacity to the system.

Q. Are there other examples where the Commission has included costs from the Company's Eastern Control Area in Washington rates?

A. Yes. In the order approving the Pacific Power / Utah Power merger, the Commission directed the Company to file a rate reduction based on the Company's projected cost reductions arising from integrating a third control area (Utah Power) into the Company's then existing system. In that order the Commission stated:

> [T]he Company demonstrated on this record that there are substantial economies to be gained in the first five years of the merger; it estimated total merger benefits of $48 million per year in the first year, increasing to $158 million per year in the fifth year. While recognizing that these are estimates, the Commission notes the benefits to be of substantial magnitude. The evidence establishing merger benefits was largely uncontradicted. Thus, the Commission's concern was that Washington ratepayers receive an equitable share of the benefits. (Second Supplemental Order, Docket No. U-87-1338-AT, page 13)

In April 1989, the Company filed a "tracker" filing, as ordered by the Commission, in which Washington rates were reduced by the Washington-allocated share of half of the first-year and half of the second-year merger benefits (projected to be $59 million on a total Company basis). These price reductions were based on cost reductions that were forecasted to occur by integrating the operation of the Company over three control areas.

Q. What are the implications for inter-jurisdictional cost allocation if the Commission were to find a generating resource to be imprudent for Washington customers although prudent on a system basis?

A. As discussed later in my testimony, from 1985-2003, Washington needed about 230 megawatts of new resources to satisfy its load growth. From 2003-2015, Washington is expected to need nearly 300 megawatts of additional new resources to meet its load growth and to replace a number of power purchased contracts that expire. If the Commission were to disallow recovery of a system-allocated share of new resources identified by the least-cost plan, then the cost of other new resources would need to be assigned to Washington to meet the needs of the Company's Washington customers. This would likely raise the cost of serving Washington customers as a result of incurring costs that are inconsistent with the Company's least-cost plan and through loss of integration benefits, as discussed above.

Q. In your view, what is the appropriate standard to be applied in judging the prudence of new resources located in the Company's Eastern Control Area?

A. The appropriate and traditional standard used by the Commission for judging the prudence of new resources is from a system-wide perspective. Under this standard, if resources are prudent from a system-wide perspective, then they are prudent for customers that are being served by that system. Judging prudence of new resources from a State-specific basis is a new and higher standard than has been required in the past. Thus, while the remainder of this section of my testimony discusses some of the Washington-specific benefits of these resources, such a showing is not required under the Revised Protocol nor is it consistent with traditional Commission policies; it is being offered only to respond to the specific issues raised by Staff in the Joint Report.

Q. What are the remaining prudence issues to be addressed in this proceeding?

A. My testimony describes why the Eastern Control Area resources discussed in the

Joint Report (Craig, Hayden, Foote Creek and Cholla) are prudent for purposes of inclusion in Washington rates. In addition, since the Company's 1999 general rate case, the Company has acquired the Gadsby, West Valley and Currant Creek resources. This filing also addresses the prudence of these resource acquisitions. Mr. Tallman's testimony addresses the prudence of these resource acquisitions from a system-wide perspective. My testimony describes why these resources – as well as Craig, Hayden, Foote Creek and Cholla – provide benefits for Washington customers, and should be included in rates.

Q. Have the Company's other jurisdictions included the resources addressed in the Joint Report in rates?

A. Yes. All of the Company's other jurisdictions have included these resources in rates, with the exception of Idaho, which has not had a general rate case either during or after the period of the resource acquisitions. Idaho has, however, ratified the Revised Protocol for use in allocating costs to the Company's Idaho jurisdiction. In addition, the Company used the Revised Protocol in its pending general rate case filing in Idaho. While the adopted treatment of other jurisdictions is not binding on the Commission, it should be an indication that these resources have been found to be reasonable in cost and necessary to serve the Company's retail customers, including those in Washington.

Q. Was an expansion of PacifiCorp's system necessary to meet the requirements of the Company's Washington customers?

A. Yes. As shown on page 1 of Exhibit No.___(GND-9), the Company acquired 1,024 megawatts of net resources through 2003, and Washington's share of those resources is approximately 82 megawatts. It also shows that during the same period, Washington megawatt hour sales increased by approximately 161 average megawatts or 229 megawatts on an annual peak basis. This demonstrates that Washington load growth contributed heavily to the need to add these resources, and that these "resources were acquired prudently to satisfy increased load growth in Washington state." If the Company had to plan for Washington's load growth separately, Washington would be allocated nearly three times the amount of resource costs than are allocated under the Revised Protocol. This reflects the value of being part of a large, diversified, integrated system and produces results that could not be achieved if the Company planned and acquired resources for Washington on a stand-alone basis.

Q. Are the allocation of resource costs to Washington expected to remain equitable in the future under the Revised Protocol?

A. Yes. As described above, Washington customers are expected to need about 300 megawatts of new resources between 2003 and 2015 both to meet Washington's growing loads and to replace expiring contracts that are currently allocated to Washington. As shown on page 2 of Exhibit No. ___(GND-9), new resource costs allocated to Washington over this same time period will closely match these needs.

Q. Do resources on both the West and East Regions of the Company's system benefit Washington customers?

A. Yes. As my following testimony discusses, resources in the East Region of the Company's system benefit Washington customers in numerous ways. Craig, Hayden and Cholla 4 resources benefit Washington customers because of peak diversity between the Company's Eastern and Western Control Areas. The Company's Eastern Control Area is summer peaking and the Western Control Area is winter peaking. This means that loads are higher in the Eastern Control Area during the summer season than during the winter season. On the other hand, the Western Control Area is winter peaking so just the opposite is true. Since the entire system is operated on an integrated basis, resources that are not being fully utilized in the Eastern Control Area are used to either serve customers in the Western Control Area, make additional wholesale sales or displace higher cost generation. The monthly level of peak diversity during the test period is shown on Exhibit No.___(GND-10).

Q. Have the resource acquisitions in the Eastern Control Area also benefited Washington retail customers through the deferral of resource acquisitions?

A. Yes. The ability to more efficiently utilize resources as a result of peak diversity has allowed the Company to defer resource acquisitions that otherwise would have been required.

Q. Are resources in the Eastern Control Area able to serve Western Control Area customers only through seasonal diversity?

A. No. The operation of the Company's system on an integrated basis also allows Eastern Control Area resources to serve Western Control Area customers when Western Control Area resources are not available due to poor hydro conditions and forced and planned outages, as long as these Eastern Control Area resources are not being fully utilized.

Q. Do Washington customers benefit from greater access to wholesale markets and a more efficient utilization of resources as a result of the acquisition of the Eastern Control Area resources?

A. Yes. As part of the Craig and Hayden and Cholla Unit 4 acquisitions, the Company also acquired additional transmission rights to and from wholesale markets. The Craig and Hayden transaction included 67 megawatts of on-peak and 100 megawatts of off-peak transmission rights to the Four Corners wholesale market. The Cholla Unit 4 acquisition included access to 350 megawatts of transmission rights in the APS control area. These additional transmission rights allow the Company to more efficiently utilize all of the Company's resources in both the Eastern and Western Control Area resources through expanded access to wholesale markets. The additional access enables the Company to make more and higher margin wholesale sales when resources are not fully utilized for retail customers and, when economic, the ability to displace higher priced resources when market purchase prices are lower. Both of these types of transactions benefit Washington retail customers by reducing net power costs. The expanded access to wholesale markets, benefits of seasonal diversity, and resource deferrals were the same factors giving rise to the benefits associated with Pacific Power's merger with Utah Power, a transaction that was found by the Commission to be in the public interest.

Q. Do the Eastern Control Area resources provide other benefits?

A. Yes. The Craig and Hayden transactions include a seasonal exchange with Tristate that provides 50 megawatts of capacity during the winter season when the

Western Control Area is experiencing peak demand. Similarly, the Cholla transaction includes a seasonal exchange currently rated at 480 megawatts during the winter season. The addition of Craig, Hayden and Cholla further enhance the Company's system reliability and flexibility in maintenance scheduling and energy dispatching, which are beneficial to all of the Company's customers, including those in Washington.

In addition to supplying energy to customers from a renewable resource, Foote Creek is providing the Company with valuable knowledge and experience in wind project operation. This has assisted our evaluation of wind via the IRP planning process and has enabled us to procure the output from wind projects located in the Northwest. Additionally, the knowledge has enabled us to enter into integration/storage/return agreements with third parties that are buying the output from wind projects interconnected to our East and West control areas. The energy returned to these third parties in the West is, in turn, used to serve end-use load in Washington (via customers of the Bonneville Power Administration and Seattle City Light). Further, by adding renewable resources to the Company's resource portfolio, Foote Creek reduces the Company's reliance on less environmentally friendly resources and provides resource diversity.

Q. To what extent did the Company use the resources in question during the test period in this case?

A. The acquired resources are utilized extensively to meet the Company's resource requirements. In total, the resources addressed in the Joint Report that are located in the Eastern Control Area provide approximately 4 million megawatt hours of net generation to serve customers. For the reasons discussed above in my testimony, the Commission has a basis for determining that the resource acquisitions were prudent from both a system-wide and a Washington perspective.

Q. Please summarize your testimony regarding the prudence of the Company's acquisition of resources between 1986 and 1999.

A. Between 1986 and 1999, the Company acquired the following resources in the Eastern Control Area: Craig and Hayden, Cholla Unit 4 and the Foote Creek Wind Project. These resource acquisitions were subjected to third-party verification and public review, including a thorough review by Staff in connection with the preparation of the Joint Report. In the Joint Report, Staff concluded that the Company's acquisition of resources was consistent with increases in load and customer growth, that the Company's decisions regarding the need to acquire new resources was guided by the Company's least-cost plan, and that on a system-wide basis the resources were acquired prudently.

These resources are "used," since they generated power to serve customers. These resources are also "useful," since they provide system-wide benefits to the Company's customers by adding operational flexibility, reducing net power costs through seasonal diversity benefits and increased access to wholesale markets, and increasing reliability and security of the Company's electricity supply. These resources provide system-wide benefits; therefore, it makes sense to evaluate their prudence on a system-wide basis. At the same time, however, if evaluated from the perspective of whether they provide benefits to

Washington, my testimony has shown the various benefits that these resources produce for the Company's Washington customers.

These resources have been added to the rate base in every State in which the Company has filed such a request. No Commission, including the Washington Commission, has disallowed resource costs solely for the reason that such resource was not located in the same control area as that State's jurisdictional loads. Staff has determined that the acquisition of these resources was prudent on a system-wide basis. Accordingly, the Company respectfully requests that the Commission include these resources in the Company's rate base in Washington.

Q. Mr. Tallman describes why Gadsby, West Valley and Currant Creek are prudent resource acquisitions from a total Company perspective. How can these resources that are located in the Eastern Control Area be used and useful in serving Washington customers that are located in the Western Control Area?

A. There are four examples of how resources located in the Eastern Control Area can benefit customers in the Western Control Area. First, to the extent that transfer capability is available, the output of these resources can be directly used to serve Washington loads. This could occur, for example, when the output of the Jim Bridger plant is reduced due to a scheduled or unscheduled outage. Second, by locating a new resource in the Eastern Control Area, the Company is able to redispatch its system to meet Washington's needs. The new resource can displace resources located in the Western Control Area that were previously being used to meet loads in the Eastern Control Area and/or optimize the resources utilized to provide reserves. The freed-up resource in the Western Control Area can then be used to meet Washington's needs. Third, these new resources can be used to help meet the Company's obligations under its cross-control area exchange contract with the Bonneville Power Administration (BPA). Under this exchange contract, the Company supplies power in the Eastern Control Area to serve BPA loads, and receive an equivalent amount of power in the Western Control Area that can be used to meet Washington loads. Finally, the power from these new resources can be sold in the wholesale markets that are accessible from the Eastern Control Area and an equivalent amount of power can be simultaneously purchased from the wholesale markets that are available to the Western Control Area. Under each of these examples, Washington customers benefit by having their incremental needs met by new resources that are least-cost to PacifiCorp, and therefore least-cost to Washington customers.

Q. Does this conclude your direct testimony?

A. Yes.