Q. Are you the same David L. Taylor who offered Direct Testimony in this proceeding?

A. Yes. My Direct Testimony was part of the Company's original filing with the Commission in December 2003.

Purpose of Rebuttal Testimony

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to:

? Address Staff witness Buckley's assertion that the Utah Pacific merger has failed the "no harm" standard for Washington customers.

? Respond to Mr. Buckley's suggestion that the costs to serve Washington customers are not, and cannot be, accurately reflected through a system wide, dynamic allocation of total Company costs and that Washington revenue requirement should be determined on a stand alone or "islanding" basis.

? Respond to Mr. Buckley's testimony that Washington is a small contributor to PacifiCorp's load growth and show that Washington has contributed, and is expected to continue to contribute, to the Company's load growth.

? Add a further explanation of why a load based, dynamic allocation for system costs assigns the vast majority of the incremental cost of load growth to the faster growing states.

? Provide additional clarification on the allocation changes contained in the Revised Protocol presented in Ms. Kelly's rebuttal testimony.

? Show the impact that the Revised Protocol would have on the Company's Washington revenue requirement that is presented in Mr. Weston's rebuttal testimony.

Rebuttal of Staff Witnesses

Q. Mr. Buckley asserts that the PacifiCorp/Utah Power merger has failed to meet the "no harm" standard and that Washington customers have been unfairly disadvantaged as a result. Are his assertions supported by the evidence?

A. No. Two observations show that PacifiCorp's Washington customers have faired very well over the 15 years since the PacifiCorp/Utah Power merger. The first observation, as discussed in Mr. Furman's testimony, is that PacifiCorp currently has the lowest residential rates out of the three investor utilities and the three largest customer owned utilities in Washington. Information directly from the Commission's web site also shows that PacifiCorp's prices have the best price history from 1995 to 2003 of the six utilities. It also shows that Tacoma City Light, Snohomish PUD and Seattle City Light, the utilities that are isolated from multi-state integration, have seen the largest price increases over the time period.

The second observation is the comparison of change in PacifiCorp's prices during the 10 years prior to the PacifiCorp/Utah Power merger with that same comparison over the 15 year-period since the merger. In the 10 years prior to the PacifiCorp/Utah Power merger (1979-1989), prices for PacifiCorp's Washington customers more than doubled. However, in the 15 years since the merger, the Company's base prices have increased by only seven percent. For our

Washington residential customers, the net prices they pay on their bills today are ***lower*** than they were in 1989.

Contrary to Mr. Buckley's assertion that Washington customers have been harmed by the merger, the history suggests just the opposite. The Company's price history shows that Washington customers have seen much greater price stability since the merger with the Utah Power system than they experienced prior to the merger.

Q. On page 21 of Mr. Buckley's testimony, he indicates that "State specific requirements" should be the basis of jurisdictional cost allocation. Do you agree and is this consistent with prior Commission decisions?

A. No, I do not agree. The state of Washington is not an island. Our Washington customers are served from a common portfolio of generation resources as part of an integrated power system. As discussed in Mr. Duvall's testimony, in an integrated system like PacifiCorp, it isn't 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. The jurisdictional allocation of total system costs across all states has been the standard for PacifiCorp, its predecessors and the state of Washington for many years. That was the standard prior to the Utah/Pacific 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. (WUTC Second Supplemental Order, Cause No. U-86-02, page 33)

Q. That order was issued before Utah Power was included as part of the PacifiCorp system. Isn't Mr. Buckley's interim proposal to use the Hybrid allocation consistent with how pre-merger Pacific Power system costs were allocated?

A. No. Following the merger between Utah Power and Pacific Power, Staff supported the Consensus allocation method, which was a single integrated system allocation methodology, although retaining the benefits of all former Pacific Power hydro resources for the former Pacific Power states. Mr. Buckley's proposal removes the Wyoming service territory and, with the exception of the Bridger plant, the Company's generation resources located in Wyoming from the allocation mix. The Wyoming service territory has been part of the Pacific Power system since 1954. The Wyoming service territory was part of the Pacific Power system in 1986, and is one of the six states referenced in the Commission's order just cited.

Mr. Buckley suggests in a number of places in his testimony that the Company's allocation proposal is unfair because it allocates portions of the "lower cost" Pacific Power resources to the former Utah Power states. By excluding the Wyoming service territory in his Western control area Hybrid proposal, however, Mr. Buckley is guilty of exactly what he finds objectionable. His proposal takes resources for which Wyoming customers have been bearing the costs for many years and reserves those resources exclusively for customers in Washington, Oregon, and California.

Q. Mr. Buckley recommends some type of "islanding" approach to setting prices in Washington. Isn't that essentially what the Company's Structural Realignment Proposal, or SRP, contemplated?

A. Not in the way Mr. Buckley seems to be suggesting. SRP provided each state with a proportional allocation of each generation resource on the PacifiCorp system. While not sufficiently developed to enable a complete analysis, it appears that Staff's islanding proposal suggests that Washington's rates would be based on a subset of system resources rather than a proportional share of all system resources.

Q. On page 78 through 81 of his testimony, Mr. Buckley discusses Washington's contribution to system load growth. Do you agree with his representations that neither Washington's historical nor its projected load growth contributes to the need for new resources?

A. No. Mr. Buckley's presentation hides much of the impact of Washington's load growth on system needs. At the time of the merger, the integrated PacifiCorp system was winter peaking. Since that time, summer loads have grown faster than winter loads and in 1999 PacifiCorp became a summer peaking system. The graph on page 4 of Mr. Buckley's Exhibit No. ___(APB-4) correctly shows each state's contribution to the annual system peak, but it doesn't inform the reader that

1993 through 1998 are winter peaks and 1999 through 2003 are summer peaks. This distorts the growth rates for the states over the time period because it compares a winter beginning point to a summer ending point. While Washington's winter peak may be relatively flat, or even declining, that is not the case for its summer peak.

Exhibit No.___(DLT-14) shows the percent change in energy usage, 12 CP, summer peak, and winter peak over the 10 years from 1993 to 2003, the same time period in Mr. Buckley's presentation. Over this time period, Washington's contribution to the summer peak grew by more than 32 percent. This is the second highest summer growth rate on the system and significantly higher than any other state except Utah.

On page 4 of Mr. Buckley's Exhibit No ___(APB-4) he uses eleven year averages in comparing Washington load shape to that of Utah. Contrary to Mr. Buckley's observation that Washington is clearly a winter peaking state, Washington has been transitioning from winter peaking to summer peaking. Starting in 2002, Washington has had a larger contribution to the system summer peak than to the winter peak. This trend is projected to continue into the future.

It is interesting that on pages 80 and 81 of his testimony, Mr. Buckley acknowledges that the 3 percent projected growth in Washington's individual state peak is "projected to be from a higher conversion rate from evaporative coolers to air conditioners and assumed larger households." These are some of the very reasons for load growth, and particularly the seasonal load growth, in Utah from which he wants to shield Washington customers.

Q. Do you agree with Mr. Buckley's concern that system-wide allocation of new resource costs shifts the cost of meeting the load growth for fast growing states onto slower growing states?

A. No. Mr. Duvall addresses this issue at length in his direct and rebuttal testimony where he shows that under a system-wide, dynamic allocation methodology the faster growing jurisdictions pick up the vast majority – in some cases more than 100 percent – of the incremental cost of new resources. The following discussion explains why.

When new Resources are added to meet load growth, all States, even if they are not growing, pick up their proportional share of the costs of the new additional Resources. At the same, a faster growing State has now become a larger portion of total system load and, as a result, through larger allocation factors, is allocated a larger share of all other system costs. The faster growing State picks up a larger share of the costs of the existing generation Resources, a larger share of the system's transmission costs, a larger share of A&G expenses and all other allocated costs.

Just the opposite happens to the slower growing States. While the slower growing States pick up a proportional share of the cost of the newly added Resource, they receive a smaller allocated portion of the costs of the existing portfolio of generation Resources, a smaller portion of the system's transmission costs, and a smaller share of A&G expenses and all other allocated costs.

An example of this was shown in Exhibit No.___(DLT-5) from my direct testimony.

Revised Protocol

Q. The Company has included the Revised Protocol as an exhibit to Ms. Kelly's testimony. Can you please provide a more detailed explanation of the changes in the classification and allocation procedures between the Revised Protocol and Protocol filed with the Company's direct case?

A. Certainly. Specifically, I will focus on the following key areas:

- ? Proposed changes to classification of Simple Cycle Combustion Turbines, or SCCTs,
- ? Proposed changes to the allocation of Regional Resources,
- ? Proposed allocation of Existing QF Contracts,
- ? Proposed elimination of Protocol language related to the allocation of transmission costs,
- ? Clarification and detail on the treatment of Special Contracts, and
- ? Estimates of the Revised Protocol's impact on the revenue requirements of each State.

As in my Direct Testimony, when I capitalize terms in this section of my Rebuttal Testimony, those terms have the same meaning as provided for in Appendix A to the Revised Protocol contained in Exhibit No. __(ALK-5).

Cost Allocation Appendices

Q. Have you prepared Exhibits that identify how all cost components of the revenue requirement are allocated among States under the Revised Protocol?

A. Yes. Exhibit No.__(DLT-15), which is Appendix B of the Revised Protocol, identifies the allocation factors applied to each component of the revenue requirement calculation. Exhibit No.__(DLT-16), which is Appendix C of the Revised Protocol, gives a detailed explanation and the algebraic formula for each allocation factor. Exhibit No.__(DLT-17), which is Appendix D of the Revised Protocol, provides a description and numerical examples of the proposed treatment of Special Contracts. I will discuss this in detail later in my testimony. Exhibit No.__(DLT-18), which is Appendix E of the Revised Protocol, provides the methodology for calculating the Annual Embedded Cost that I also discuss later in my testimony.

<u>Classification of Simple Cycle Combustion Turbine Fixed Costs</u>

Q. In your direct testimony, PacifiCorp proposed to classify the fixed costs of SCCTs differently from the remainder of the Company's Resources. Has the Company reconsidered this proposal?

A. Yes. The Company now proposes to classify the Fixed Costs of SCCTs on the same basis as all other Resources. Although SCCTs are generally designed and operated to run during peak-load periods, rather than to produce sustained, low cost energy, we have been persuaded that there are valid reasons to continue past allocation practices that classify the Fixed Costs of all Resources as 75 percent Demand-Related and 25 percent Energy-Related.

Q. What are those reasons?

A. First, as discussed in my Direct Testimony, a wide range of demand and energy classification methods could be supported on a technical basis. Given the diversity of PacifiCorp's Resource portfolio, it has been argued that certain Resources should be classified more heavily to Demand-Related and that certain

Resources should be classified more heavily to Energy-Related. The classification of all Resources as 75 percent Demand-Related and 25 percent Energy-Related appears to fairly recognize this balance. To single out one type of Resource – SCCTs – for special treatment could upset the balance and lead to unnecessary complexity and ambiguity for classification of all Resources.

Second, the proposed change recognizes that the operation of Resources on a year-to-year basis varies due to load and market factors and may be different from the expected operation when the Resources were acquired. Finally, the Company agrees with several parties that, absent a compelling reason to change, minimizing changes from current allocation practices will aid in implementation of the Protocol and limit cost shifts among States.

Q. Does the Company propose to eliminate the Seasonal Resource designation for allocation of SCCTs and include them as part of System Resources?

A. No. SCCTs will continue to be treated as Seasonal Resources with their costs allocated using seasonal allocation factors as described in my Direct Testimony.

Cost Allocation for Regional Resources

Q. What changes is the Company proposing to the allocation of Regional Resources?

A. As discussed in Ms. Kelly’s testimony, the Company proposes to eliminate the coal endowment and to eliminate the ability for Oregon to opt out of the First Major New Coal Resource. In addition, the Company proposes a change to the allocation of costs related to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.

Hydro-Electric Resources and Mid-Columbia Contracts

Q. Please explain how the costs of Hydro-Electric Resources are assigned and allocated under the Revised Protocol.

A. In the Revised Protocol, the existing and future investment and operating costs of Hydro-Electric Resources are, in the first instance, allocated on a system-wide basis. Then, the total normalized costs of Hydro-Electric Resources are compared against the normalized costs of the remaining generation portfolio on a $/MWH basis and an adjustment which reflects the cost difference is applied. This adjustment is referred to as "The Owned-Hydro Embedded Cost Differential Adjustment."

The Owned-Hydro Embedded Cost Differential Adjustment is calculated as the Annual Embedded Costs – Hydro-Electric Resources, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from the Hydro-Electric Resources used to set rates. The adjustment is then allocated to former Pacific Power jurisdictions using the DGP factor and the reciprocal amount (All Other less Hydro) will be allocated to all States using the SG factor. Currently the adjustment is negative (the Hydro-Electric Resource costs are less expensive than all other Resources), so it is a net credit to the former Pacific Power jurisdictions and a cost to the other jurisdictions. In the future, the adjustment is forecasted to become positive (the Hydro-Electric Resource costs are more expensive than all other Resources). At that time the adjustment would be a net cost to the former Pacific Power jurisdictions and a credit to the other jurisdictions.

Mid-Columbia Contracts and Existing QF Contracts

Q. Please explain how the costs of Mid-Columbia Contracts are assigned and allocated under the Revised Protocol.

A. Similar to Hydro-Electric Resources, the costs of Mid-Columbia Contracts are, in the first instance, allocated on a system-wide basis. Then, the total normalized costs of Mid-Columbia Contracts are compared against normalized costs of the remaining generation portfolio on a $/MWH basis and an adjustment which reflects the cost difference is applied. This adjustment is referred to as the "Mid-Columbia Contracts Cost Differential Adjustment."

The Mid-Columbia Contracts Cost Differential Adjustment is calculated as the Annual Mid-Columbia Contract Costs, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from the Mid-Columbia Contracts. The adjustment is then allocated to all States using the Mid-Columbia (MC) factor and the reciprocal amount (All Other less Mid-C) is allocated to all States using the SG factor.

The calculation of the MC factor is shown in Appendix F of the Revised Protocol and described in detail in Mr. Duvall's Supplemental Direct Testimony.

Q. Please describe how the costs of Existing QF Contracts are assigned and allocated under the Revised Protocol.

A. Existing QF Contracts are treated similarly to the Hydro Resources and the Mid-Columbia Contracts. Like Hydro-Electric Resources, the costs of QF Contracts are, in the first instance, allocated on a system-wide basis. But then, unlike the Hydro Electric Resource and Mid-Columbia Contract costs, which are compared to other generation costs at an aggregate level, the Existing QF cost difference is calculated separately for each State. The Existing QF Contract costs in each State are compared against normalized costs of the remaining generation portfolio on a $/MWH basis and an adjustment which reflects the cost difference is applied. This adjustment is referred to as "Existing QF Contracts Cost Differential Adjustment".

The Existing QF Contracts Cost Differential Adjustment is calculated as the Annual Existing QF Contracts Costs for a specific State, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from that State's Existing QF Contracts. This adjustment is situs assigned to that State. The sum of this adjustment for all States is calculated and an adjustment for the reciprocal amounts (All Other less Total System QF) is allocated to all States using the SG factor.

Q. How are the Company's Annual Embedded Costs calculated?

A. Annual Embedded Costs are calculated for Hydro-Electric Resources, Mid-Columbia Contracts, Existing QF Contracts, and all other Resources. They are based on fully normalized test period costs captured in the FERC accounts identified in Appendix E to the Revised Protocol, Exhibit No.__(DLT-18).

As shown on lines 1 through 11 of Appendix E, the Annual Embedded Costs - Hydro-Electric Resources include the identified hydro-related operation and maintenance, depreciation, and amortization expenses plus the identified hydro- related rate base items times the pre-tax authorized (or requested) return on rate base, $70,969,571 in this example. This amount is divided by the annual hydro MWh, from the GRID run used in the test period net power cost calculation, 4,128,973 MWh, to arrive at the Annual Embedded Costs – Hydro-Electric Resources of $17.19 per MWh.

The Annual Costs, MWh, and corresponding cost per MWh are shown for Mid-Columbia Contracts and total Existing QF Contracts on lines 12 and 13, respectively.

The Annual Embedded Costs - All Other are shown on lines 14 through 44. This calculation is similar to the costs for Hydro-Electric Resources described above and results in Annual Embedded Costs – All Other of $32.00 per MWh. This is the cost to which Annual Embedded Costs - Hydro-Electric, Annual Mid-Columbia Contract Costs, and Annual Existing QF Costs are compared.

Q. Did the Company evaluate alternatives to the Embedded Cost Differential as a form of Hydro Endowment?

A. Yes. The following three alternatives to the Embedded Cost Differential were proposed and evaluated in the course of the MSP:

- Combining the Hydro Endowment with a Coal Endowment,
- Using or modifying the fuel adjustment mechanism, and
- Reinstating a load decrement approach.

I will discuss the reasons for the rejection of these approaches in favor of the "embedded cost differential."

Q. Why did the Company abandon its proposal to combine the Hydro Endowment with a Coal Endowment, as described in your direct testimony?

A. It did not enjoy support from MSP participants.

Q. Please describe the existing "fuel adjustment mechanism".

A. The fuel adjustment mechanism that is part of the Modified Accord allocation methodology:

- ? Calculates the difference (on a $/MWH basis) between the 5-year average of the O&M Expenses of the Company's Hydro-Electric Resources and the O&M Expenses of the Company's Thermal Resources;
- ? Multiplies the $/MWH difference by the MWHs of generation from Hydro-Electric Resources, and then allocates the difference as a credit to the former Pacific Power jurisdictions and as a charge to all jurisdictions; and
- ? Allocates the costs of post-1989 capital investments across the system based on each State's proportional load in a test period.

A corresponding calculation is also calculated for the former Utah Power Hydro-Electric Resources.

Q. Please discuss the drawbacks of the existing fuel adjustment mechanism.

A. One primary drawback is that the mechanism compares only the operating costs of thermal and Hydro-Electric Resources and therefore does not account for the Fixed Costs of either type of Resource. Another problem is that it does not equitably match the distribution of the benefits of Hydro-Electric Resources with the responsibility for the expected substantial increase in capital costs for the relicensing and other capital investments associated with Hydro-Electric Resources. That is to say, under Modified Accord, all States bear a proportionate share of post Utah/Pacific merger Hydro-Electric Resource capital costs, but only former Pacific Power States receive the fuel cost advantage of Hydro-Electric Resources.

Q. Did parties consider options that would address these inequities?

A. Yes. Parties evaluated a short-term fuel adjustment mechanism that phased out as the revenue requirement of relicensing costs exceeded the fuel benefits. However, this approach did not eliminate the inequities. This mechanism incorporated a mismatch of costs in that it involved a comparison of both the Fixed Costs and Variable Costs of Hydro-Electric Resources against only the Variable Costs of thermal Resources. Again, some States received credits for fuel benefits for the next several years but all States bore the risk of the costs of relicensing. Additionally, this approach was rejected by some parties because it was not permanent.

Q. Please describe the "load decrement approach."

A. Under the load decrement approach, the costs of Hydro-Electric Resources are assigned to and allocated among the former Pacific Power jurisdictions. At the same time, the loads of the former Pacific Power jurisdictions are reduced by the output of the Hydro-Electric Resources, prior to the development of allocation factors for the remaining System Resources. This reduces the Pacific Power jurisdictions' allocated share of the cost of the remaining System Resources. This type of approach was utilized under the Accord Method from 1993 to 1997.

Q. Why isn't the Company proposing to reinstate the load decrement approach?

A. Our studies have revealed drawbacks to this mechanism. Most significantly, the load growth studies revealed that the load decrement approach distorts the allocation of costs associated with load growth to the States with decremented loads. Not only are States with decremented loads allocated a smaller share of existing remaining System Resources, they are also allocated a smaller share of the cost of new System Resources. This is in conflict with the principle that States should pay for the costs of their load growth to the maximum extent possible.

<u>Transmission Costs</u>

Q. How has the Company revised the Protocol in respect to the classification and allocation of transmission costs?

A. In its initial proposal, PacifiCorp included an allocation provision that would have applied in the event commissions approve its participation in a Regional Transmission Organization ("RTO"). The proposal was simply to allocate charges from the RTO among the States based upon the same billing determinants relied upon by the Federal Energy Regulatory Commission in setting the RTO's rates. Several parties expressed concern that this proposal was premature given the evolving regional RTO discussions and requested that the provision be eliminated. The Company has complied with those requests and removed that provision.

<u>Special Contracts</u>

Q. Has the Company modified its proposal regarding the treatment of Special Contracts?

A. No. However, Appendix D, Exhibit No.__(DLT-17), has been added to the Protocol for greater clarity. Appendix D identifies two general types of Special

Contracts: 1) Special Contracts without Customer Ancillary Service Contract attributes, and 2) Special Contracts with Customer Ancillary Service Contract attributes. For both types of Special Contracts, the cost of serving contract customer loads, and their State-approved retail service revenues, will be included in the local State's revenue requirement. However, the regulatory treatment of the two types of Special Contracts is different. My explanation of the difference follows.

For allocation purposes Special Contracts without Customer Ancillary Service Contract attributes are viewed as one transaction and the system benefits and load reductions accruing from customer interruptions are treated very similarly to DSM. In the same manner as DSM, the host jurisdiction benefits from both the reduction in system costs and the reduction in its jurisdictional loads. The host jurisdiction is allocated a smaller share of the lower total system costs. In other words, it is a smaller piece of a smaller pie.

Specifically, loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors. When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors. Actual revenues received from a Special Contract customer will be assigned to the State where the Special Contract customer is located. A numeric example of the regulatory treatment of Special Contracts without Ancillary Service Contract attributed is shown in Appendix D, Table 1.

For allocation purposes Special Contracts with Customer Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the ancillary service contract rate. Loads associated with the retail service to the Special Contract customers will be included in all Load-Based Dynamic Allocation Factors. The Customer Ancillary Service Contract attributes of the Special Contract are viewed not as a reduction in load, but rather as the acquisition of Resources to meet Company load. Therefore, when interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur. Revenues received from the Special Contract customer, before any discounts for Customer Ancillary Service Contract attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located. Because discounts from tariff prices provided for in Special Contracts or payments to retail customers recognize that the Customer Ancillary Service Contract attributes of the Contract are considered as payments for Resource acquisitions, they will be allocated among States on the same basis as System Resources. A numeric example of the regulatory treatment of Special Contracts with Customer Ancillary Service Contract attributes is shown in Appendix D, Table 2.

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements.

The cost associated with the buy- through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy- through will not be included in State revenues. Revenue Requirement Impacts

Q. Have you prepared an exhibit showing the impact of the Revised Protocol on revenue requirements?

A. Yes. Exhibit No.__(DLT-19), presents estimates of impacts on each State's revenue requirement. Estimated revenue requirements for California, Oregon, Washington, and Wyoming are compared to the Modified Accord methodology. Estimated revenue requirements for Idaho and Utah are compared to the Rolled-In methodology. A positive percent indicates the State's revenue requirement for a given year under the Revised Protocol is higher and a negative percent indicates the revenue requirement under the Revised Protocol is lower. The year-by-year revenue requirement impacts are shown for the period 2005 thorough 2018 as well as the Net Present Value of the difference in revenue requirements over the 14-year period. For each State, the percent change in revenue requirement associated with the effect of moving from Modified Accord to Rolled-In (if applicable), the Hydro Endowment (both Company Owned and Mid-C components), Existing QF Contracts and Seasonal Resources is shown first followed by the impact of the Revised Protocol.

Q. What are the important analytical assumptions underlying these calculations?

A. They include projections of Hydro-Electric Resource relicensing costs, expected new Resources as reflected in the Company's 2003 IRP, clean air investments and a carbon tax commencing in 2008.

Q. What factors are not reflected in the calculations?

A. The calculations do not include the potential State-by-State revenue requirement impacts of New QF Contracts, Special Contracts and Portfolio Resources.

Q. What do you conclude from Exhibit No. __(DLT-19)?

A. I conclude that the revenue requirement impacts are within an acceptable range. While the Revised Protocol produces somewhat lower revenue requirements for Oregon, Washington, and Wyoming in the early years, the trend reverses and those States see larger revenue requirements in the later years. The higher Revised Protocol revenue requirements seen by Utah and Idaho in the early years are offset by lower revenue requirements in the later years.

Q. Have you prepared an exhibit that shows, for illustrative purposes, the impact of the Revised Protocol on the Company's proposed revenue requirement in this case?

A. Yes I have. Exhibit No. ___(DLT-20) shows the revenue requirement impact of the Revised Protocol compared to the originally filed MSP Protocol. Page 1 shows the comparison and pages 2 and 3 show the State of Washington revenue requirement summaries under the originally filed MSP Protocol and the Revised Protocol, respectively. Page 4 contains the Embedded Cost Differential calculations for the test period and page 5 shows the allocation impacts of Company Owned Hydro, Mid-Columbia Contracts and Existing QF Contracts Embedded Cost Differentials. Exhibit No. ___(DLT-21) contains the PacifiCorp, State of Washington, Twelve Months Ended March 2003, Results of Operations calculated using the Revised Protocol.

Based on the Total Company normalized costs as presented in Mr. Weston's rebuttal testimony, PacifiCorp's revenue requirement in the State of Washington under the Revised Protocol is $221,790,087, which would suggest a rate increase of $23,200,988 or 11.68 percent. This is $2,457,826 or 1.1 percent less that the revenue requirement indicated by the originally filed MSP Protocol.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.