Q. Please state your name, business address and position with PacifiCorp dba Utah Power & Light Company (the Company).

A. My name is David L. Taylor. My business address is 825 N. E. Multnomah, Suite 800, Portland, Oregon, where I am employed as the Revenue Requirement and Cost of Service Director.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a BS in Accounting from Weber State College in 1979 and an MBA from Brigham Young University in 1986. I have been employed by PacifiCorp since the merger with Utah Power in 1989. Prior to the merger I was employed by Utah Power, beginning in 1979. At the Company I have worked in the Accounting, Budgeting, and Pricing and Regulatory areas. From 1987 to the present I have held several supervision and management positions in Pricing and Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified on numerous occasions in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. In my testimony I will describe the jurisdictional allocation changes between the Rolled-in Allocation Methodology previously adopted by the Utah Commission and the Revised Protocol allocation methodology proposed by the Company. A stipulation (“Stipulation”) in support of the ratification of the Revised Protocol was filed with the Commission in Docket No. 03-035-04 on June 28, 2004 and is attached as Exhibit UP&L___(DLT-1). Additionally I will detail the impacts of those allocation changes on the Utah revenue requirement. Finally, I will show the impact of the Utah Revenue Requirement Rate Mitigation Cap that is contained in the stipulation.

Q. How is the Revised Protocol Allocation Methodology similar and how is it different from the Rolled-in Allocation Methodology?

A. Transmission costs, Distribution costs, and the majority of Generation costs are treated in the same manner as they were under the Rolled-in Allocation Methodology. There are two areas where the Revised Protocol allocated costs differently than the Rolled-in Method. First there are three types of Seasonal Resources which are allocated using seasonally weighted allocation factors. Second, there are three Embedded Cost Differential Adjustments. I will discuss each of these later in my testimony.

All Resource Fixed Costs, Wholesale Contracts and Short-term Purchases and Sales continue to be classified as 75 percent Demand-Related and 25 percent Energy-Related. All costs associated with Non-Firm Purchases and Sales continue to be classified as 100 percent Energy-Related. Other than the Seasonal Resources, described below, Generation and Transmission demand related costs continue to be allocated using the 12 CP method and energy related costs continue to be allocated using annual energy consumption.

Cost Allocation for Seasonal Resources

Q. How are the costs of Seasonal Resources allocated differently than the costs of System Resources?

A. In contrast to the allocation of non-seasonal resources described above, each state's contribution to system peak and energy usage is weighted seasonally in development of the allocation factors for Seasonal Resources. Prior to summing the twelve monthly Coincident Peaks, each monthly CP measurement is weighted by the monthly portion of the total annual energy generated by the Seasonal Resource. For example, if 30 percent of the annual generation of a particular Seasonal Resource occurs in July, the monthly Coincident Peak for July would be weighted by 30 percent in the calculation of the allocation factor. This, in essence, allocates 30 percent of the Demand-Related Cost for that Resource among states based upon their contribution to the July Coincident Peak.

Similar to the weighting of Demand-Related costs, each state's monthly energy usage is weighted by that month's portion of annual energy generation for the particular Resource. The annual fuel costs for that Resource are then allocated using its seasonally weighted energy factor.

Somewhat different procedures are used for simple-cycle combustion turbines, Seasonal Contracts and the costs of Cholla Unit IV. The calculation of the seasonally weighted allocation factors for each of the Seasonal Resources is shown in Exhibit UP&L__(DLT-2). Page 1 of this exhibit contains the temperature normalized monthly energy and monthly contribution to system Coincident Peak for each of the states. Pages 2 through 4 detail the factor calculation for the costs of simple-cycle combustion turbines, Seasonal Contracts and the costs of Cholla Unit IV respectively.

Q. How are the costs of Simple-Cycle Combustion Turbines (SCCTs) allocated?

A. Both the Demand-Related and Energy-Related Costs are assigned to the individual months of the year on the proportional basis of the annual dispatch hours for the given month in which those resources are dispatched to meet retail load.

Q. How are the costs of Seasonal Contracts allocated?

A. As with the SCCTs, the cost of Seasonal Contracts are allocated on a weighted monthly basis according to their monthly delivered megawatt hours. Because some of the contracts do not have explicit Demand and Energy components, however, the entire contracts will be classified as 75 percent Demand

Q. How are the costs of the Cholla plant allocated differently from SCCTs?

A. The Cholla plant is considered a winter Seasonal Resource. Although the Cholla Unit IV is operated all year except for times of required maintenance, a substantial portion of the summer output is delivered to Arizona Pubic Service Company ("APS") and an equivalent amount of capacity and energy is returned to PacifiCorp during the winter months.

The costs of the Cholla plant are allocated using a similar monthly weighting methodology as used for SCCTs with an adjustment for the megawatt hours delivered to and received from APS. Both the demand and energy components of plant costs are assigned to months on the basis of monthly megawatt hours dispatched from Cholla plus megawatt hours received from APS less megawatt hours delivered to APS. This assigns the majority of the Cholla costs to five winter months, October through February.

Embedded Cost Differential Adjustments

Q. Earlier in you testimony you indicated that there were three Embedded Cost Differential Adjustments. Please explain these adjustments and how calculated.

A. The Revised Protocol introduces a new concept of affording states value from their allocated share of Hydro-Electric Resources and Mid-Columbia Contracts through an "embedded cost differential" calculation. Additionally cost responsibility for the existing Qualifying Facilities (QF) located in each state is more directly assigned to that state through another "embedded cost differential" calculation.

Generally speaking, the costs of Company owned Hydro Resources, the Mid-Columbia Contracts and Existing QF Contracts are first allocated on a system-wide, rolled-in basis. After the system-wide allocation, a separate "embedded cost differential" calculation then compares the total embedded cost of Hydro-Electric Resources, Mid-Columbia Contracts and Qualifying Facilities on a dollar per MWh basis with the total embedded cost of the Company's other Resources (excluding the costs of Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts). The difference in cost is then multiplied by the normalized output from the Hydro-Electric Resources, Mid-Columbia Contracts and QF Contracts. If the difference is negative (the Hydro-Electric Resources, Mid-Columbia Contracts or QF costs are less expensive than other Resources), it is credited to the states with the hydro endowment, or the state where the QF is located. If the difference is positive (the Hydro-Electric Resources, Mid-Columbia Contracts or QF costs are more expensive than other Resources), there is a charge to the hydro endowment states, or state where the QF is located.

More specifically, the Owned-Hydro Embedded Cost Differential Adjustment is allocated to former Pacific Power jurisdictions using the DGP factor, the Mid-Columbia Contracts Cost Differential Adjustment is allocated to all states using the Mid-Columbia (MC) factor, and the Existing QF Contracts Cost Differential Adjustment is calculated for each specific state and assigned situs assigned to that state.

The total Company reciprocal amount for each of these adjustments is allocated to all states using the SG factor. This nets each state's allocated or direct assigned share of each embedded cost differential, as just described, against their share of that same differential that was, in the first instance, allocated on a system-wide basis.

Q. How are the Company's Annual Embedded Costs used in the embedded cost differentials calculated?

A. Exhibit UP&L__(DLT-3) details the Annual Embedded Costs calculation for Hydro-Electric Resources, Mid-Columbia Contracts, Existing QF Contracts, and all other Resources. As shown on lines 1 through 11, 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. This amount is divided by the annual hydro MWh, from the GRID run used in the test period net power cost calculation to arrive at the Annual Embedded Costs – Hydro-Electric Resources of $17.77 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 $32.52 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. Have you prepared an exhibit that details the impact of each of the allocation changes on the Utah Revenue Requirement?

A. Yes. Exhibit UP&L ___(DLT-4) shows the impact of each allocation change. Lines 1 through 34 of the Exhibit show the difference between Utah's allocated share of SCCTs, Seasonal Contracts, and Cholla costs as allocated in this case using seasonal allocation factors, and how those same costs would have been allocated using the Rolled-in methodology. Lines 36 through 49 show the net impact for each of the embedded cost differential adjustments.

Rate Mitigation

Q. Please describe the Rate Mitigation Cap that is contained in the Stipulation.

A. Paragraph two of the Stipulation states:

> 2. Rate Mitigation Caps.
>
> In order to mitigate potential rate impacts on Utah customers, any increase in the Utah revenue requirement as a result of the implementation of the Revised Protocol shall be capped at the Applicable Percentage of the Company's Utah Revenue Requirement calculated under the Rolled-in Allocation Method for the indicated effective periods as follows:
>
> a. 101.50 percent for the period from the effective date of the final PSCU order in the first general rate proceeding filed after the effective date of this Stipulation and the Revised Protocol, to March 31, 2007.

Q. What is the impact of the Rate Mitigation Cap in this case?

A. As shown in Exhibit UP&L___(DLT-5), the Utah FY06 revenue requirement is capped at $1,266,825,565, or 101.5 percent of the Utah Revenue Requirement as calculated under the Rolled-in Allocation Method. The Rate Mitigation Cap limits the PacifiCorp requested rate increase request to $111,022,484, or 9.6 percent, which is $12,623,934 less than the non-mitigated rate increase calculated using the Revised Protocol as described in Mr. Weston's testimony.

Q. Does this conclude your testimony?

A. Yes it does.