BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Joint Application of PACIFICORP and PACIFICORP, WASHINGTON, INC. for an Order Approving (1) the Transfer of Distribution Property from PacifiCorp to an Affiliate, PacifiCorp, Washington, Inc., (2) the Transfer by PacifiCorp of Certain Utility Property to an Affiliate, the Service Company, and (3) the Proposed Accounting Treatment for Regulatory Assets and Liabilities, and an Order Granting an Exemption under RCW 80.08.047 for the Issuance or Assumption of Securities and Encumbrance of Assets by PacifiCorp, Washington, Inc. and/or PacifiCorp	Docket No. UE-001878

PACIFICORP

DIRECT TESTIMONY OF
DAVID L. TAYLOR

June 2001

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

A. My name is David L. Taylor. My business address is 825 N. E. Multnomah, Suite 800, Portland, Oregon 97232 and my present position is Manager of Revenue Requirement and Cost of Service.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a B.S. in Accounting from Weber State College in 1979 and an M.B.A. 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. In my 22 years with the Company I have worked two years in Accounting, three years as a Budget Coordinator in one of the Company's Region Offices, and over 16 years in the Pricing and Regulatory areas. From 1987 to the present I have held several supervisory 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.

Summary of Testimony

Q. What is the purpose of your testimony?

A. My testimony covers four areas. First, I describe the scenarios that we have modeled with respect to the revenue requirement impact of the Company's proposal with respect to the revenue requirement impact of the Company's proposal and present a comparison of the future revenue requirement estimates for each state under each scenario. My testimony presents two scenarios for permanently allocating among states the value of the Company's existing generating resources compared against a method that dynamically allocates generating resources on an annual basis. This is a method that we believe is no longer viable). Second, I explain the different load growth and electricity market price forecasts used to establish a range of potential outcomes for each of the three allocation scenarios. Third, I outline the modeling procedures used to estimate the future revenue requirements for each state, including the estimated impacts of the contracts between each state electric company and both the generation company and the service company. Finally, I describe the determination of costs for the proposed service company (Service Company) and the allocation of those costs between PacifiCorp Generation and the state electric companies.

SCENARIOS

Q. Please describe the generating resource allocation scenarios used in your modeling.

A. We refer to the three generating resource allocation scenarios as "Reference Case", "Structural Realignment Proposal" (SRP), and "Island States".

Reference Case

Q. Please describe the Reference Case.

A. The Reference Case scenario is provided as a basis of comparison against which to evaluate the long-term revenue requirement impacts of the other two scenarios. The Reference Case assumes that PacifiCorp could continue its process of allocating the costs of generating resources among states reflecting year-to-year variations in each state's contribution to the requirements it places on the system. This allocation process is in conflict with the requirements of Oregon's restructuring legislation and inhibits the Company's ability to respond to state-specific energy policy decisions. The Company does not present this scenario as a viable long-term alternative.

Q. Is the Reference Case based on different ratemaking assumptions than are reflected in current ratemaking practices ?

A. Yes. The Reference Case: a) assumes that the Company earns the same equity return on its rate base (11.5%) across all states, b) establishes net power costs on the basis of a model that matches resources against hourly loads and market prices and c) incorporates the "Fair Share" method of interjurisdictional cost allocation.

Q. Why does the Reference Case assume that the Company is recovering the same return across all states?

A. We believe this is necessary in order to accurately assess the marginal impact of other scenarios which include the same assumption.

Q. Why does the Reference Case assume that net power costs will be established based upon a model that matches resources against hourly loads and market prices?

A. This approach is different than that reflected in the current PD MAC model which is based upon monthly average loads and market prices. Continued reliance upon monthly averages has been a source of controversy in recent rate proceedings, given recent market price volatility. We have concluded that it is likely that future rates will be set base upon an hourly net power cost model. Based upon that assumption, it seemed that a Reference Case in this proceeding would prove more meaningful if it took the same approach.

Q. What effect does the use of the hourly model have on net power costs and total revenue requirement?

A. All else being equal, it appears to increase net power costs and total revenue requirement.

Q. What is the Fair Share Method?

A. Dr. Rodger Weaver's direct testimony describes the Fair Share method for allocating costs among states using a compromise approach between the current Rolled-In and Modified Accord allocation methodologies. The Fair Share method treats all states equitably, and provides the Company with the opportunity to recover all prudently incurred costs. The Reference Case scenario uses the Fair Share method for allocating costs.

Structural Realignment Proposal (SRP)

Q. Please describe SRP.

A. The SRP scenario analyses the impacts of the corporate restructuring proposed in this proceeding to create individual state electric companies, a generation company and a service company. SRP is designed to provide a permanent allocation of existing generation benefits and costs among the states served by PacifiCorp Generation through the Short-Term and Long-Term Power Purchase Agreements (Agreements) between each of the six state electric companies and PacifiCorp Generation. The entitlement to existing generation that is permanently assigned to each state varies on a monthly basis to capture seasonal load variations and to minimize system balancing requirements. This scenario also uses the Fair Share method for allocating costs.

Once the permanent allocation of existing generating resources is accomplished, each state electric company is responsible for the cost of meeting its own load growth. The state electric companies share an undivided interest in PacifiCorp's existing firm transmission rights to achieve hourly system balancing requirements. Under SRP, the benefit of the integrated operation of the existing system is preserved. The terms of the Agreements and the system balancing requirements are discussed in detail in Mr. Gregory Duvall's supplemental direct testimony. A detailed description of the SRP corporate structure is contained in Mr. Pete Craven's testimony.

Island States

Q. Please describe the Island States.

A. The Island States scenario also accomplishes a permanent allocation of existing generating resources, but without a change to the Company's corporate structure. Unlike SRP, under Island States, each state electric company receives a fixed share (or "slice") of each of the Company's generating resources that does not vary by month and receives a fixed slice of existing transmission capacity. This scenario also relies on the Fair Share method for allocating costs. Each state electric company is then responsible for the costs of hourly system balancing using its assigned firm transmission rights.

Load Growth and Electricity Market Price Assumptions

Q. Please describe the load growth forecasts used to develop the various scenarios.

A. Under each generating resource allocation scenario, revenue requirements are estimated for two different load growth forecasts.

Q. Please describe the two load forecasts.

A. We refer to these forecasts as "Forecast I" and "Forecast II". Load Forecast I reflects continued high load growth in Utah. Load Forecast II reflects relatively balanced growth across all states, beginning in 2006. For both of these load forecasts, we used three separate methodologies for forecasting state-by-state system peak and energy:

Short-term forecast: Using 1998 as the base year, we developed a three-year forecast - 1999 through 2001 - of energy and system peaks using the short-term methodology described in Exhibit 3.1 of Application Exhibit 5.

Long-term forecast: We developed a twenty-year forecast – 1999 through 2018 – of energy and system peaks using the methodology historically used in PacifiCorp's least-cost planning studies. The Company adjusted the fourth year of the long-term forecast to provide a smooth transition between the short-term forecast and the long-term forecast through 2005, Load Forecast I and Load Forecast II are identical.

Escalation beyond twenty years: To develop an energy forecast for years beyond 2018, the Company calculated an average annual growth rate for each state using twenty years of historical data and the twenty years of forecast data. The Company also calculated an average load factor over the same forty years and applied that average load factor to develop the system peak forecast for years beyond year twenty.

Q. Please describe the three electricity market price forecasts.

A. We refer to these three forecasts as "Cyclic Growth", "Bullish Gas" and "Commodity Competition".

Cyclic Growth (CG)

The Cyclic Growth scenario depicts the gas and electric industries recovering relatively quickly from the 2000-02 price run-up and then exhibiting cyclic supply additions that, on average, maintain balance with demand. Gas prices settle to $3.50 by 2004 then hold at $3.70 until 2010. Western System Coordinating Council (WSCC) generation additions in the 2001-03 time frame restore balance and adequate reserves to the electric markets, and then keep pace with modest demand growth, averaging just over 2% through 2010.

Bullish Gas (BG)

Under the Bullish Gas scenario the gas industry is challenged to keep pace with demand over this scenario, with tight gas supplies of 2001 easing gradually over several years. Healthy economic and demand growths persist after the pause in 2001, with demand growth across the WSCC averaging 2.5%. Natural gas prices decline gradually in 2002-3 from the historic highs of 2001 to a new, higher plane, with prices in the $4.50 range for the remainder of the decade. New generation additions in the WSCC catch up with demand growth by 2003, then maintain a reasonably balanced supply picture. These gas prices prompt renewed interest in base-load coal development. Cost of new gas-fired generation escalates in real terms.

Commodity Competition (CC)

This Commodity Competition scenario depicts a wrenching readjustment in the gas and electric industries following the 2000-01 price run-ups. An economic recession in 2002-03 allows gas supplies and power developments to not just catch up with the shortages that led to the price run-ups, but to overshoot them, leading to an overhang of supply through much of the first decade. Generation capacity additions in the pipeline persevere, in spite of the absence in demand growth throughout the WSCC between 2001 and 2003. Accelerated technological developments and public policy during this time period favor demand-side efficiencies and distributed generation, yielding demand growth of only 1.75% after 2003 and reinforcing the supply imbalance. Declining costs of new power construction over this period also exacerbate the supply competition. With diminished supply growth in response to the absence of wholesale margins, the gas and generation overhang is worked off and a more balanced supply-demand picture emerges in the 2011-15 period.

Q. Please explain Exhibit ___(DLT 1) and Exhibit ___(DLT2)?

A. Exhibits ___ (DLT 1) and ___ (DLT 2) provide a summary of revenue requirement estimates produced by the Company's Regulatory Forecast Model (RFM). The purpose of these exhibits is to show, using a common data set, the estimated revenue requirement impact of SRP and Island States compared against the Reference Case. The estimated revenue requirements are escalated from a 1999 test period consistent with the Company's Resource Plan included as Application Exhibit 5. The revenue requirement analyses are intended to provide a relative comparison between the scenarios, rather than a basis for setting current or future rates. As discussed in the direct testimony of Mr. C. Alex Miller (subsequently adopted by Mr. Pete Craven), the state electric companies will eventually file new tariffs that will establish rates, terms and conditions for service and effectuate the transfer of the obligation to serve. Exhibit ____ (DLT 2) shows thirty years of revenue requirement estimates as well as 10-year, 20-year and 30-year net present value (NPV) of the revenue requirement stream for Washington under the three generating resource allocation scenarios for two load growth and three market price forecasts. Exhibit ____ (DLT 1 presents a comparison of the 30-year NPV of revenue requirements for SRP and Island States with the Reference Case revenue requirement under each load forecast and market price forecast.

Q. What conclusions do you draw from these comparisons?

A. SRP accomplishes a permanent allocation of generating resources in a manner that protects customers in all states from the potentially significant revenue requirement increases seen under the Island States scenario. SRP fulfills the objectives set forth in Mr. Matthew Wright's supplemental direct testimony and the requirements of Oregon's restructuring plan while reducing customer impacts from that seen under the Island States scenario. The Company's Structural Realignment Proposal significantly reduces the long-term customer rate impacts under all three market price forecasts (Commodity Competition, Cyclic Growth, Bullish Gas).

- Under the Commodity Competition market price case, the range of 30-year NPV impacts are reduced from approximately 3.5% to 5.5% in the Island States scenario to (1%) to .5% in SRP.
- Under the Cyclic Growth market price case, the range of 30-year NPV impacts are reduced from approximately 6% to 11.5% in the Island States scenario to (2%) to 1.5% in SRP.

- Under the Bullish Gas market price case, the range of 30-year NPV impacts are reduced from approximately 10% to 17% in the Island States scenario to (3%) to 2% in SRP.

Revenue Requirement Modeling Procedures

Q. Please describe the modeling procedures used to determine the revenue requirement estimates for each of the state electric companies.

A. The revenue requirement estimates for each of the state electric companies were developed using the RFM. The RFM first separates all costs and assets by generation, transmission, or distribution function and then performs jurisdictional allocation and revenue requirement calculation procedures. The generation function represents costs that will flow to the state electric companies as a result of each State electric company's Power Purchase Agreement with PacifiCorp Generation. The transmission function represents the costs that will flow to each state electric company via transmission charges from PacifiCorp's transmission organization and third parties. The distribution function represents the costs that are incurred directly by the state electric companies (including Service Company costs). The sum of the three functions equals the total retail revenue requirement for each state electric company.

Q. How are the contract charges from the Service Company reflected in the RFM?

A. Contract charges from the Service Company to PacifiCorp Generation are reflected as Administrative &General (A&G) expense in the generation function and are allocated to each state according to energy consumption (the SE factor).

Service Company contract charges to the transmission organization are reflected as A&G expense in the transmission function and are allocated to states in the same manner as transmission assets (the SG factor). Service Company charges to each state electric company are included as A&G expense in the distribution function.

Q. What base year data was used in the model and how was that data escalated to future test periods?

A. The expenses and assets in the RFM model are based on 1999 actual data. The 1999 data was rolled forward to 2001 using traditional methods for development of a future test period. The data was then escalated for each subsequent year.

1999 O&M costs were adjusted to remove the costs associated with the Centralia Plant and then separated between labor and non-labor components. Both the labor and non-labor components were escalated to 2001 using appropriate DRI indices. For each year after 2001, O&M expenses were escalated at 2.8% per year.

Capital plant additions from 1999 through 2010 were based on the 10-year forecast used in Application Exhibit 5. Capital additions from 2011 to 2031 were based on the average plant addition for the 10-year forecast period escalated at 2.8% per year.

Plant-related deferred tax expense, deferred tax balance and Schedule M items were provided by our Tax Dept.'s ACUFILE model. Non-plant related deferred tax expense, deferred tax balance and Schedule M items were based on a 10-year Schedule M forecast.

Q. Are these assumptions used in all of the scenarios?

A. Yes.

Q. What are the notable differences between the scenarios from a modeling standpoint?

A. Revenue requirement differences between the Reference Case and SRP are driven by two major factors. First, each state's entitlement to existing generating resources is locked in using allocation factors forecasted to be in effect in 2005. These entitlements are then shaped on a monthly basis to reflect seasonal load characteristics, to maintain existing system efficiencies and to minimize system balancing requirements. Second, each state pays the costs associated with its own load growth.

Revenue requirement differences between SRP and Island States are driven by two additional factors. First, the states are assigned a fixed share of the existing generating resources that does not vary on a month-to-month basis. Second, the states are assigned a fixed share of the existing firm transmission rights. Both of these factors diminish current integrated system efficiencies and increase each state's system balancing costs

PacifiCorp Services Company

Q. How were the O&M expenses for PacifiCorp Services Company determined?

A. In his direct testimony, Mr. Pete Craven described the purpose and structure of the Service Company. In that testimony he also included a partial listing of departments and functions that will be part of the Service Company. A complete listing of departments and services can be found in Exhibit I of the PacifiCorp Services Agreement, attached to Mr. Craven's supplemental direct testimony. The 1999 O&M expenses for each of these organizations were identified and included as the base year data in the Service Company Contract model. The 1999 costs were then escalated to future periods using the same assumptions as those used to escalate other non-fuel O&M expenses in the RFM Model. The 1999 costs for the Service Company organizations were also removed from the base year data of the RFM that was used to estimate the revenue requirements for PacifiCorp Generation and each state electric company.

Q. How was the value of the Service Company assets determined?

A. All general and intangible plant assets not directly associated with PacifiCorp Generation, or one of the state electric companies, are included as Service Company assets. 1999 Year-end gross plant balances for these assets were included as the base year data in the Service Company Contract model and removed from the base data in the RFM model. Accumulated depreciation and amortization as well as depreciation and amortization expense for the General and Intangible Plant was proportionally assigned to PacifiCorp Generation, each state electric company and the Service Company. Plant additions and retirements for each of the forecast years were then added.

Q. How were the Service Company expenses and assets used to determine the annual yearly Contract price estimates to PacifiCorp Generation and each state electric company?

A. The costs for each of the Service Company organizations were allocated between PacifiCorp Generation and each state electric company to the extent possible according to the allocation procedures outlined in Exhibit III of the PacifiCorp Services Agreement. In very limited cases where the basis for the preferred allocation factor was not currently available a reasonable substitute was used for modeling purposes. Service Company-related general and intangible plant investment was also allocated between the Service Company and each state electric company using a set of allocation procedures. After the allocations were complete, a standard revenue requirement calculation was performed to determine the Contract billing between the Service Company and PacifiCorp Generation and each state electric company.

Q. Were 100% of the costs of each Service Company organization captured in the Service Company Contract model?

A. No, but this does not change the overall results of the revenue requirement analysis. The majority of the Service Company costs flow through the Service Company Contract model. In the 1999 base data, however, some of the costs for several Service Company departments have already been directly assigned to capital projects and to the operating expenses of various PacifiCorp business units. There was no way to identify and remove these costs from the base 1999 data. In practice these costs will flow through the Service Company Contract, but for modeling purposes here, they are already included as direct expenses.

Q. Does this conclude your testimony?

A. Yes.