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

A. My name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite 800, Portland, Oregon 97232, and my present position is Principal System Planner.

Q. Have you previously submitted pre-filed direct testimony in this docket?

A. Yes.

Summary of Supplemental Testimony

Q. Will you please summarize your supplemental testimony?

A. I will present the results of the production cost model study for the twelve months ended September 30, 2000 test period. I will describe the major causes of the significant increases in the Company's net power costs since the last Utah rate case in Docket No. 99-035-10. I will also describe the alternative methodology to PD/Mac used to calculate net power costs, as well as provide information on how input data is normalized in the Company's production cost model and the rationale for doing so. I also address certain normalizing adjustments contained in Exhibit UP&L _____ (DDL-___), which is the Company's Utah Results of Operations Report for the twelve-month test period ended September 30, 2000. Specifically, my testimony explains normalizing Adjustments 5.3 and 5.5.

Net Power Cost Results

Q. What are the results of the Company's September 30, 2000 test period net power cost study?

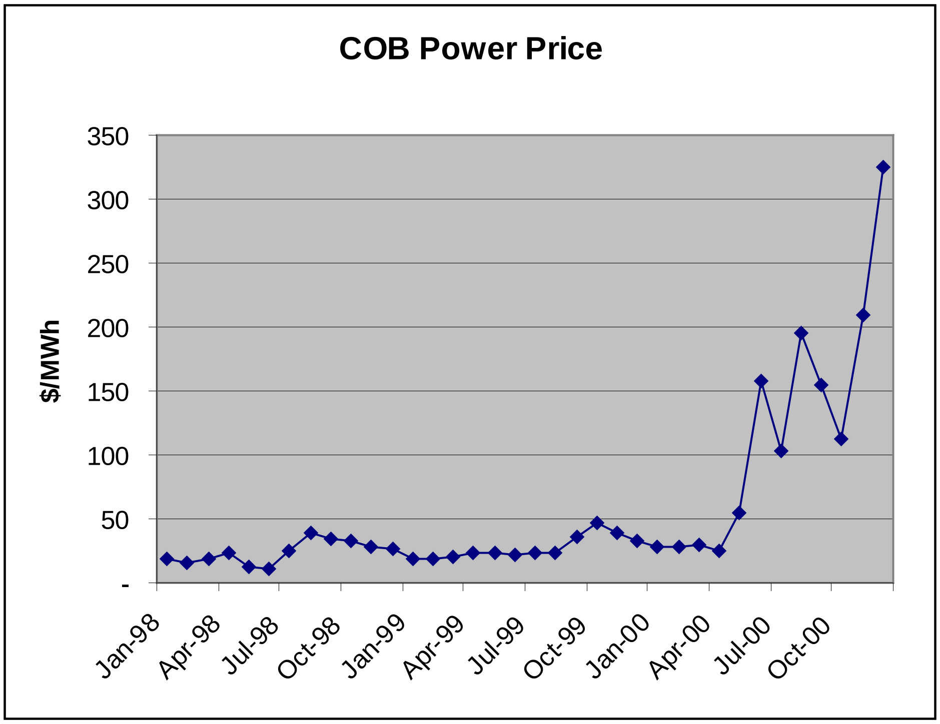
A. The Company's September 30, 2000 normalized net power costs are approximately $813 million on a total company basis.

Q. How do those net power costs compare to the Company's 1998 normalized net power costs from Utah Docket No. 99-035-10?

A. The proposed net power costs are approximately $387 million higher on a total company basis.

Q. Please explain the primary cause for the increase in net power costs.

A. The market price of power has skyrocketed at all the western region trading points where the Company purchases power, such as the California-Oregon Border (COB), Mid-Columbia (Mid-C), Palo Verde (PV), and the California Power Exchange (CalPX). As shown in the chart below, COB power prices spiked up from an average cost of $36.69 per MWh in November 1999 to approximately $312 per MWh in December 2000. Prices at other trading points such as Mid-C and PV have climbed steeply also. COB prices are cited to illustrate the magnitude of recent changes in the market.



Looking forward, the COB forward power market is pricing power at an even higher level for the entire twelve months ending December 2001 than occurred during 2000. This unabated spike in power costs has rocked the industry. Despite these high prices, Utah Power customers have been shielded by PacifiCorp's stable tariffs from the extreme power costs.

Q. Does the electric energy market show signs of returning to historic price patterns?

A. No, not in the next year. Even more damaging than 2000 prices is the ominous evidence that market power prices in 2001 are expected to be even higher.

Table 1
COB Forward Price Curve (Flat) Feburary 2001 – January 2002

$/MWh	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bid	$173	$344	$294	$232	$227	$229	$293	$356	$332	$265	$267	$258
Ask	$204	$404	$313	$272	$264	$252	$313	$380	$354	$298	$300	$290
Mid	$188	$374	$303	$252	$245	$240	$303	$367	$343	$281	$283	$274
Average Midpoint												$288

As shown on Table 1, over the next twelve months, current market prices show an average monthly high of $404 per MWh in February 2001 and a low of $188 per MWh in January 2002. Certain daily and hourly prices are expected to exceed the monthly average. All this contrasts sharply with the average short-term market price of $22.19 per MWh adopted in Utah Docket No. 99-035-10. Further, the replacement power to cover the outage at Hunter 1, which is not a part of this request, is approximately $97 million through January 2001. The total company impact related to all purchased power costs is huge.

Q. What has driven electricity prices so high?

A. There has been much speculation and analysis regarding the cause of high market prices but the exact causes have yet to be determined. A combination of high gas prices and significant growth in electricity demand coupled with little new generation capacity, CalPX price caps and generation limits due to emission credits has certainly contributed to the high market prices experienced throughout the West during 2000. Until these problems are resolved, there is no reason to expect that market prices will stabilize at significantly lower levels. What is clear is that the price increase is extraordinary and is driven by forces beyond management control.

Q. Has the Company's resource portfolio helped protect its customers from the full impact of wholesale price increases?

A. Yes. The Company has not had to rely on market purchases to meet load requirements to the same extent as other utilities.

Q. What is the Company doing in response to these conditions?

A. The Company has adopted a prudent strategy to hedge against market price volatility. These efforts include the exploration of load management opportunities as well as buying power on the forward market to cover a portion of the Company's short positions.

Determination of Net Power Cost

Q. Are the proposed net power costs developed in a manner consistent with previous determinations?

A. Yes, with the exception of the Company's net power cost model. As ordered by the Public Service Commission of Utah in Docket No. 99-035-10, the Company did not use PD/Mac to calculate the Net Power Cost in this docket.

Q. Please explain how net power costs were calculated.

A. The Company calculated net power costs on a normalized basis using a spreadsheet model, as an alternative to PD/Mac. The model is used to simulate the operation of the power supply portion of the Company under a variety of stream flow conditions. The results obtained from the various stream flow conditions are averaged and the appropriate cost data is applied to determine an expected net power cost under normal stream flow and weather conditions for the test period.

Q. Please explain the how the production cost model estimates net power costs.

A. The development of expected net power costs begins with the selection of either a forecast or historic test period. My testimony will focus on the use of a historical test year. I have divided the description of the power cost model into three categories:

1. The model used to calculate the net power costs.
2. The inputs that go into the model.
3. The output provided by the model.

Alternative Methodology to PD/Mac

Q. Please describe the methodology employed to calculate the net power costs in this Docket.

A. The net power costs are calculated on a monthly basis. The general steps are as follows:

1. Determine the temperature adjusted retail load.
2. Determine the level of thermal generation, based on normalized availability and maintenance. Thermal generation is displaced if lower cost purchases are available.
3. Calculate the thermal generation expenses using the normalized fuel costs.
4. Determine both the energy amount and expenses (revenues) of long term and short term firm wholesale purchases (sales).
5. Determine the wheeling expenses.
6. Determine the level of hydro generation, based on the 50 water-year records.
7. For every month of every water year, calculate the system balances on both east and west sides of the Company's system.

8. Buy secondary energy if there is a deficit, and sell secondary energy if there is a surplus.

Q. What are the components of the net power costs?

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase expenses and wheeling expenses, less wholesale sales revenue. With the exception of secondary purchase expenses and secondary sales revenue, all the components have been calculated by steps 3 through 5 above.

Q. Please describe how secondary purchases and sales are incorporated in the net power costs.

A. After steps 7 and 8, for each month there are 50 secondary purchase volumes and sales volumes, one corresponding to a water year. The secondary purchase volumes are averaged to obtain normalized secondary purchase volume, and the secondary sales volumes are averaged to obtain normalized secondary sales volume. The normalized purchase and sale volumes are then multiplied by secondary purchase and sale prices, respectively, to determine secondary purchase expense and secondary sales revenue. They are added to the corresponding components in the net power costs.

Model Inputs

Q. Please explain the inputs that go into the model.

A. As mentioned above, inputs into the production cost model include retail loads, thermal plant data, hydroelectric generation data, firm wholesale sales, firm wholesale purchases, firm wheeling expenses, and nonfirm wholesale sales and purchase market data.

Q. Please describe the retail load that is used in the model.

A. The retail load represents the monthly firm retail loads that the Company served within all of its jurisdictions for the twelve-month period ended September 30, 2000. These loads have been adjusted to reflect normal temperature conditions.

Q. Please describe the thermal plant input data.

A. The amount of energy available from each thermal unit and the unit cost of the energy are needed to calculate net power costs. To determine the amount of energy available, the Company averages for each unit, four years of historical operating equivalent availability reduced by the four-year average maintenance.

The unit cost of energy for each unit is determined by using a four-year average of historical burn rate data. By using four-year averages for maintenance, historical availability and burn rate data, annual fluctuations in unit operation and performance are smoothed. The four-year period used by the Company for this filing is 1996 through 1999.

Q. Please describe the hydroelectric generation input data.

A. Fifty years of monthly hydroelectric generation for Company-owned hydro plants in the Northwest and Mid-Columbia purchased resources are input into the model. The hydro data that is input into the production cost model is from the Bonneville Power Administration (BPA) Hydro Regulation computer program (Hydro Regulation). Data from Hydro Regulation is based on actual stream flows for the period August 1928 through July 1978. Hydro Regulation simulates the hydroelectric generation at each facility on the major rivers in the Pacific Northwest based on inputs provided by each member of the Northwest Power

Pool, Idaho Power Company, and the Assured Operating Plan of the Canadian Utilities. The purpose of Hydro Regulation is to maximize the firm energy capability of the Pacific Northwest hydroelectric system. It is based on hydroelectric plant efficiencies, storage capabilities and requirements, minimum flow requirements (including fish requirements), regional loads and resources, and non-power operating constraints.

Q. Is the input of hydro generation located outside of the Northwest modeled in the same manner as the Pacific Northwest hydro generation?

A. No. The input of hydro generation located in Utah and Southeast Idaho was calculated as the actual average monthly hydroelectric generation for the years 1974 through 1999. A shorter time frame is used for the Utah and Southeast Idaho hydro resources than the Company's other hydro resources because their relative size is small, there is no overall area model analogous to the Hydro Regulation model in the Northwest and there is a lack of reliable data for the earlier years.

Q. Please describe the input data for firm wholesale sales, purchases, and wheeling expenses.

A. The data for firm wholesale sales, purchases, and wheeling are all based on contracts to which the Company is a party. Each contract specifies the basis of quantity and price. The contract may specify an exact quantity of capacity and energy or a range bounded by a maximum and minimum amount, or it may be based on the actual operation of a specific facility. Prices may also be specifically stated, may refer to a rate schedule, a market index such as COB or PaloVerde, or may be based on some type of formula.

Q. Please describe the nonfirm wholesale sales and purchase input assumptions.

A. The production cost model requires inputs relating to two non-firm wholesale sales markets. There are two markets in the calculation: east and west. As a result of the significant increase in wholesale market prices that occurred during the test year and the expectation that high prices will continue, short-term wholesale sales and purchase prices are based on actual prices incurred by the Company for the period June 2000 through September 2000. Because of the expectation that higher market prices will continue, prices for the period October 1999 through May 2000 were annualized to reflect prices incurred by the Company during the period June–September 2000.

Normalization

Q. Please explain what is meant by normalization and how it applies to the production cost model for historical test years.

A. Normalization for a historical test year is the process of modifying actual test year data by removing all known abnormalities and making adjustments for all known changes. Normalization produces test year results that are representative of expected conditions with none of the abnormalities that occur in each actual year. The availability of energy from Company-owned and purchased hydroelectric generation is normalized by running the production cost model for each of the 50 different water years identified in the Hydro Regulation.

Q. You stated that hydroelectric generation is normalized by using historical water data. Please explain why the regulatory commissions and the utilities of the Pacific Northwest have adopted the use of production cost studies that employ historical water conditions for making these normalization adjustments.

A. In any hydroelectric-oriented utility system, water supply is one of the major variables affecting power supply. The operation of the thermal electric resources both within and outside the Pacific Northwest are directly affected by water conditions within the Pacific Northwest. During periods when the stream flows are at their lowest, it is necessary for utilities to operate their thermal electric resources at a higher level or purchase more from the market, thereby experiencing relatively high operating expenses. Conversely, under conditions of high stream flows, excess hydroelectric production may be used to reduce generation at the more expensive thermal electric plants, which in turn results in lower operating expenses for some utilities and an increase in the revenues of other utilities, or any combination thereof. No one water condition can be used to simulate all the variables that are met under normal operating conditions. Utilities and regulatory commissions, therefore, have adopted production cost analysis that simulates the operation of the entire system using historical water conditions, as being representative of what can reasonably be expected to occur.

Model Outputs

Q. What variables are calculated from the production cost study?

A. These variables are:

1. The amount of thermal generation required;

2. Secondary sales on the east and west sides of the Company's system;

3. The secondary energy purchased on the east and west sides of the Company's system.

Q. Do you believe that the production cost model appropriately represents the Company's operating relationship with the other utilities and markets?

A. Yes.

Q. Please describe Exhibit UP&L _____ (MTW-____).

A. Exhibit UP&L _____ (MTW-_____), entitled "Normalized Sources of Energy – Utah, 12 Months Ending September 30, 2000," is a schedule of the Company's major sources of energy supply by major source of supply, expressed in average megawatts, owned and contracted for by the Company to meet system load requirements for the test period. The total shown on line 14, represents the total normalized usage of resources during the test period to serve system load. Line 15 consists of wholesales sales made to neighboring utilities within the Pacific Northwest, the Pacific Southwest, and the Desert Southwest as calculated from the production cost model study. Line 16 represents the Company's System Load net of special sales.

Q. Please describe Exhibit UP&L ______ (MTW-_____).

A. Exhibit UP&L _____ (MTW-______), entitled "Normalized Sources of Peak Capacity – Utah, 12 Months Ending September 30, 2000," lists the major sources of peak generation capability for the Company's winter and summer peak loads and the Company's energy load for the test period.

Q. How are the results of the production cost study used in this rate proceeding?

A. The resulting purchased power expense, fuel and wheeling expenses and wholesale sales revenues are included in Mr. Larson's Exhibit UP&L _____ (DDL-____), which is the Company's Results of Operations for the test period.

Normalizing Adjustments

Q. Please explain Net Power Cost adjustments 5.3 and 5.5 contained in Tab 5 of Mr. Larson's Exhibit UP&L _____ (DDL-_____).

A. **Sacramento Municipal Utility District (SMUD) Revenue Imputation** (Adjustment 5.3) - In Docket No. 99-035-10, the Commission imputed the Southern California Edison (SCE) contract rate of $37 per MWH to the SMUD contract. Adjustment 5.3 imputes sales for resale revenues to reflect the ordered rate, thus increasing Utah revenues by $2,900,925.

Wholesale Contract Revenue Imputation (Adjustment 5.5) - In Docket No. 99-035-10 the Commission ordered the Company to impute revenues on six wholesale contracts. Two of the contracts expired during the test period and were normalized out. Adjustment 5.5 imputes revenues on the remaining four contracts which increases Utah revenues by $485,353.

Q. Does this conclude your direct testimony?

A. Yes.