EXHIBIT D

Q. Please state your name, business address and present position with Rocky Mountain Power Company (the Company), a division of PacifiCorp.

A. My name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232, and my present title is Director, net power costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Administration from Oregon State University. I have worked for the Company since 1980 and have held various positions in the power supply and regulatory areas. I was promoted to my present position in September 2004.

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost and related analyses used in retail price filings. In addition, I represent the Company on power resource and other various issues with intervenor and regulatory groups associated with the six state regulatory commissions to whose jurisdiction we are subject.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I present the Company's proposed net power costs. In addition, my testimony:

- Describes the Company's production cost model, the Generation and Regulation Initiatives Decision Tools (GRID) model, which is used to calculate net power costs;
- Provides information on how input data is normalized in GRID and the

rationale for doing so; and

- Describes the change in hydro modeling associated with the VISTA hydro model.

Net Power Cost Results

Q. Please explain net power costs.

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Please explain how the Company calculates net power costs.

A. Net power costs are calculated using the GRID model. For each hour in the test period, the model simulates the operation of the power supply portion of the Company under three stream flow conditions. The results obtained from the 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. What are the proposed normalized net power costs?

A. The normalized net power costs for the twelve months ended June 2009 are approximately $456.4 million on a Utah allocated basis, or $1.091 billion system-wide. The Company's net power cost study is provided as Exhibit RMP___(MTW-1). The allocation of total Company net power costs to Utah is presented in Exhibit RMP___(SRM-1) in Mr. Steven McDougal's testimony.

Q. How do these compare with the level currently included in rates?

A. Rates for Docket 06-035-21 were established based on a global settlement of the entire case, without specific findings on the net power cost level. Therefore, it is not possible to identify the exact magnitude of the cost increase from the prior case. The projected level of net power costs in this case, however, is more than 34 percent higher than the $811 million filed with the last case. In general, the largest factors causing the cost increase are higher retail loads, higher coal prices, higher market and natural gas costs, and expiring purchase power contracts. These increases are mitigated by the addition of wind resources.

Q. How does increased retail load impact the Company's proposed net power costs?

A. This filing reflects a system-wide increase in load of 3.2 million megawatt hours (5.6 percent) when compared to total Company loads included in Docket 06-035-21. All things being equal, additional retail load will require the Company to re-dispatch the system utilizing additional higher cost thermal resources and by making additional market purchases and reduced market sales.

Q. Please explain the sources of the increase in the Company's gas costs.

A. Gas prices have trended sharply upward over the last several years, and they remain volatile, with both price spikes and price softening. The Company's gas costs included in this filing reflect market prices, plus cost increases or decreases to reflect the Company's hedged position.

The general upward trend in price coupled with extreme market price volatility makes hedging an important risk mitigation tool to manage the Company's cost of gas. The Company's gas procurement and risk management strategy is discussed in detail in Mr. Lasich's testimony. While the Company's hedged position in Docket 06-035-21 decreased gas costs, the current filing reflects gas costs that are higher because the hedged position is above market. The Company's gas costs for this case were primarily hedged between November 2005 and May 2006, after market prices had increased following hurricane Katrina.

Q. Please explain the Company's coal fuel price increases.

A. The coal price increases at our generation facilities are being driven by a variety of factors, including normal increases in contract price indices, the impact of contract re-openers, and higher mine operating costs.

Q. Can you give examples of these cost increases?

A. Yes. The Company's Deer Creek mine reflects a cost increase of $11 million or $3.89/ton. This increase is caused by a combination of lower expected annual tonnage coupled with increased labor, benefits, insurance and royalties. The cost of fuel supplied by the Arch coal purchase causes an increase of $15 million due to a price re-opener as well as contract escalation.

Q. Why do expiring purchase power contracts generally increase net power costs?

A. The Company's purchase power contracts generally reflect wholesale electric market prices at the time they were executed. As wholesale electric market prices increase, the cost of replacement power increases when a contract expires. This filing reflects the expiration of various contracts, including the 400-megawatt TransAlta contract, and the increased costs of replacement power associated with these expiring contracts. The expiration of the TransAlta and Duke Power contracts increases net power costs by $70.8 million.

Q. Are the cost increases partially offset by the inclusion of the variable costs from renewable energy facilities expected to be in service during the test period?

A. Yes. The net power costs include expected generation from the 94-megawatt Goodnoe wind project located in Oregon, which is presently expected to be in-service June 2008; the 140-megawatt Marengo wind generation facility located in Washington, that came on line August 2007 and is being upgraded to 210-megawatts by August 2008; the 99 megawatt Glenrock wind project located in Wyoming, which is presently expected to be in service December 2008, the 99 megawatt Seven Mile Hill wind project located in Wyoming, which is expected to be in service by December 2008 and the 100-megawatt Leaning Juniper wind generation facility located in Oregon that came on line September 2006. Because the Company owns these wind facilities, the variable cost of these resources is zero. These resource additions reduce total Company net power costs by $83.8 million.

Determination of Net Power Costs

Q. Are these proposed net power costs developed with the same production dispatch model used in the Company's last Utah filing?

A. Yes, with one exception. The Company's proposed net power costs were developed using version 6.2 of the GRID model. In the last Utah filing (Docket No. 06-035-21), the Company used GRID version 5.2/5.3.

Q. Please explain the changes in GRID version 6/1, including whether they impact net power costs.

A. The first is a change in the power plant commitment logic, so that if the marginal unit's reference market is illiquid, the model does not calculate a reserve credit. This change has only a minimal impact on power costs.

The second change replaces the Thermal Heat Rate data series with a Heat Rate Coefficient data series. The model calculates the heat rate curve within the model. The new data series is a timed-attribute data series. This allows the analyst to change Huntington Unit 2's curve to reflect the impact of the new scrubber without maintaining two different data series, for example. Again, the change has only minimal impact on net power costs.

The third change generally improves the functionality of the model by enhancing security for projects with "locked" scenarios, providing an MMBTU report and providing financial reports with finer granularity in long term contract cost reporting.

Q. Please explain the changes in GRID version 6.2, including whether they impact net power costs.

A. The first change enhances the system balancing logic to better recognize economic displacement by decommitting eligible thermal units. Previously, the Company used a manual workaround. The net power cost impact of this change ranges from no change to a decrease depending upon parameters of the entire portfolio of resources.

The second change improves the dispatch of resources with zero minimum up and down time settings. The net power cost impact is either a small decrease or a small increase depending upon parameters of the entire portfolio of resources.

The third change provides the capability to include a loss payment for transmission losses as part of the total hourly transmission link cost. The net power cost impact of this change is zero at the current time.

The fourth change provides the capability to include a capacity payment and other cost in the total monthly transmission link cost. The net power cost impact of this change is zero at the current time.

The fifth change improves the efficiency of the system balancing algorithm. The net power cost impact of this change is zero.

The sixth change provides enhanced functionality for greater analyst efficiency. The net power cost impact of this change is zero.

Q. Please explain how GRID projects net power costs.

A. I have divided the description of the power cost model into three sections, as shown below:

- The model used to calculate net power costs
- The model inputs
- The model output

The GRID Model

Q. Please describe the GRID model.

A. The Generation and Regulation Initiatives Decision Tools (GRID) model is the Company's hourly production dispatch model, which is used to calculate net power costs. It is a server-based application that uses the following high-level technical architecture to calculate net power costs:

- An Oracle-based data repository for storage of all inputs
- A Java-based software engine for algorithm and optimization processing
- Outputs that are exported in Excel readable format
- A web browser-based user interface

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

A. Net power costs are calculated hourly using the GRID model. The general steps are as follows:

1. Determine the input information for the calculation, including retail load, wholesale contracts, market prices, thermal and hydro generation capability, fuel costs, wind generation, transmission capability and expenses
2. The model calculates the following pre-dispatch information:
    - Thermal availability
    - Thermal commitment
    - Hydro shaping and dispatch
    - Energy take of long term firm contracts
    - Energy take of short term firm contracts
    - Reserve requirement and allocation between hydro and thermal resources
3. The model determines the following information in the Dispatch (optimization) logic, based on resources, including contracts, from the pre-

dispatch logic:

- Optimal thermal generation levels, and fuel expenses
- Expenses (revenues) from firm purchase (sales) contracts
- System balancing market purchases and sales necessary to balance and optimize the system and net power costs taking into account the constraints of the Company's system
- Expenses for purchasing additional transmission capability

4. Model outputs are used to calculate net power costs on a total Company basis, incorporating expenses (revenues) of purchase (sales) contracts that are independent of dispatched contracts, which are determined in step 3.

The main processors of the GRID model are steps 2 and 3.

Q. Please describe in general terms, the purposes of the Pre-dispatch and Dispatch processes.

A. The Dispatch logic is a linear program (LP) optimization module, which determines how the available thermal resources should be dispatched given load requirements, transmission constraints and market conditions, and whether market purchases (sales) should be made to balance the system. In addition, if market conditions allow, market purchases may be used to displace more expensive thermal generation. At the same time, market sales may be made either from excess resources or market purchases if it is economical to do so under market and transmission constraints.

Q. Does the Pre-dispatch logic provide thermal availability and system energy requirements for the Dispatch logic?

A. Yes. Pre-dispatch, which occurs before the Dispatch logic, calculates the availability of thermal generation, dispatches hydro generation, schedules firm wholesale contracts, and determines the reserve requirement of the Company's system. In my following testimony, I'll describe each of these calculations in more detail.

Generating Resources in Pre-Dispatch

Q. Please describe how the GRID model determines thermal availability and commitment.

A. The Pre-dispatch logic reads the inputs regarding thermal generation by unit, such as nameplate capacity, normalized outage and maintenance schedules, and calculates the available capacity of each unit for each hour. The model then determines the hourly commitment status of thermal units based on planned outage schedules, and a comparison of operating cost vs. market price if the unit is capable of cycling up or down in a short period of time. The commitment status of a unit indicates whether it is economical to bring that unit online in that particular hour. The availability of thermal units and their commitment status are used in the dispatch logic to determine how much may be generated each hour by each unit.

Q. How does the model shape and dispatch hydro generation?

A. In the Pre-dispatch logic, the Company's available hydro generation from each non-run of river project is shaped and dispatched by hour within each week in order to maximize usage during peak load hours. The weekly shape of a non-run of river project is based on the net system load. The dispatch logic incorporates minimum and maximum flow constraints for the project to account for hydro license constraints. The dispatch of the generation from run-of-river projects is flat in all hours of the week. The hourly dispatched hydro generation is used in the Dispatch logic to determine energy requirements for thermal generation and system balancing transactions.

Wholesale Contracts in Pre-Dispatch

Q. Does the model distinguish between short-term firm and long-term firm wholesale contracts in the Pre-dispatch logic?

A. Yes. Short-term firm contracts are block energy transactions with standard terms and a term of one year or less in length. In contrast, many of the Company's long-term firm and intermediate-term firm contracts have non-standard terms that provide different levels of flexibility. For modeling purposes, long-term firm contracts are categorized as one of the following archetypes based on contract terms:

- Energy Limited (shape to price or load): The energy take of these contracts have minimum and maximum load factors. The complexities can include shaping (hourly, annual), exchange agreements, and call/put optionality.
- Generator Flat (or Fixed Pattern): The energy take of these contracts is tied to specific generators and is usually the same in all hours, which takes into consideration plant down time. There is no optionality in these

contracts.

- Fixed Pattern: These contracts have a fixed energy take in all hours of a period.
- Complex: The energy take of one component of a complex contract is tied to the energy take of another component in the contract or the load and resource balances of the contract counter party.
- Contracted Reserves: These contracts do not take energy. The available capacity is used in the operating reserve calculation.
- Financial: These contracts are place holders for capturing fixed cost or revenue. They do not take energy.

In the Pre-dispatch logic, long-term firm purchase and sales contracts are dispatched per the specific algorithms designed for their archetype.

Q. Are there any exceptions regarding the procedures just discussed for dispatch of short-term firm or long-term firm contracts?

A. Yes. Whether a wholesale contract is identified as long-term firm is entirely based on the length of its term. Consistent with previous treatment, the Company identifies contracts with terms greater than one year by name. Short-term firm contracts are grouped by delivery point. If a short-term firm contract has flexibility as described for long-term firm contracts, it will be dispatched using the appropriate archetype and listed individually with the long-term contracts. Hourly contract energy dispatch is used in the Dispatch logic to determine the requirements for thermal generation and system balancing transactions.

Reserve Requirement in Pre-Dispatch

Q. Please describe the reserve requirement for the Company's system.

A. The Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) set the standards for reserves. All companies with generation are required to maintain operating reserves, which comprise two components – regulating reserve and contingency reserve. Companies must carry contingency reserves to meet the most severe single contingency (MSSC) or 5 percent for operating hydro and wind resources and 7 percent for operating thermal resources, whichever is greater. A minimum of one-half of these reserves must be spinning. Units that hold spinning reserves are units that are under control of the control area. The remainder (ready reserves) must be available within a 10-minute period. NERC and WECC require companies with generation to carry spinning reserves to protect the WECC system from cascading loss of generation or transmission lines, uncontrolled separation, and interruption of customer service.

Regulating Reserve is an amount of Spinning Reserve immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria.

Q. How does the model implement the operating reserve requirement?

A. The model calculates operating reserve requirements (both regulating reserve and contingency reserve) for the Company's East and West control areas. The total contingency reserve requirement is 5 percent of dispatched hydro and wind, plus 7 percent of committed available thermal resources for the hour, which includes both company-owned resources and long-term firm purchase and sales contracts that contribute to the reserve requirement. Spinning reserve is one half of the total contingency reserve requirement. In GRID, regulating margin is added to the spinning reserve requirement. Regulating margin is the same in nature as spinning reserve but it is used for following changes in net system load within the hour.

Q. How does the model satisfy reserve requirements?

A. Reserves are met first with unused hydro capability, then by backing down thermal units on a descending variable cost basis. Spinning reserve is satisfied before the ready reserve requirement. For each control area, spinning reserve requirement is fulfilled using hydro resources and thermal units that are equipped with governor control. The ready reserve requirement is met using purchase contracts for operating reserves, uncommitted quick start units, the remaining unused hydro capability, and by backing down thermal units. The allocated hourly operating reserve requirement applied to the generating units is used in the Dispatch logic to determine the energy available from the resources and the level of the system balancing market transactions.

Q. What is an "uncommitted quick start unit"?

A. As noted above, ready reserves must be available within a 10-minute period. A quick start unit is a unit that can be synchronized with the transmission grid and can be at capacity within the 10-minute requirement. If a gas supply is available and the units are not otherwise dispatched, the Gadsby combustion turbine units meet this requirement.

Q. Are the operating reserves for the two control areas independent of each other?

A. Yes, with one exception for spinning reserves. The dynamic overlay component of the Revised Transmission Services Agreement with Idaho Power allows the Company to utilize the reserve capability of the Company's West side hydro system in the East side control area. Up to 100 megawatts of East control area spinning reserves can be met from resources in the West control area.

Q. What is the impact of reserve requirement on resource generating capability?

A. There is no impact on hydro generation, since the amount of reserves allocated to hydro resources are based on the difference between their maximum dependable capability and the dispatched energy. However, if a thermal unit is designated to hold reserves, its hourly generation will be limited to no more than its capability minus the amount of reserves it is holding.

GRID Model Inputs

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

A. Inputs used in GRID include retail loads, thermal plant data, hydroelectric generation data, wind plant generation data, firm wholesale sales, firm wholesale purchases, firm wheeling expenses, system balancing wholesale sales and purchase market data, and transmission constraints.

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

A. The retail load represents the normalized hourly firm retail load that the Company expects to serve within all of its jurisdictions for the twelve-month period ending

June 30, 2009. This load is modeled based on the location of the load and transmission constraints between generation resources to load centers.

Q. Please describe the thermal plant inputs.

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 outage rates and maintenance. The heat rate for each unit is determined by using a four-year average of historical burn rate data. By using four-year averages to calculate outages, maintenance and heat rate data, annual fluctuations in unit operation and performance are smoothed. For this filing, the 48-month period ending June 2007 is used. Other thermal plant data includes unit capacity, minimum generation level, minimum up/down time, fuel cost, and startup cost.

Q. Are there any exceptions to the four-year average calculation?

A. Yes. Some plants have not been in service for the entire four-year period. For those plants, the Company uses the manufacturer's expected value for the missing months to produce a weighted average value of the known and theoretical rates.

Q. Please describe the hydroelectric generation input data.

A. The Company uses the output from the VISTA hydro regulation model for GRID's hydroelectric generation input data. The Company uses three sets of expected generation from VISTA. The VISTA model is described in more detail later in my testimony.

Q. Does the Company use other hydro generation inputs?

A. Yes. Other parameters for the hydro generation logic include maximum capability, minimum run requirements, ramping restrictions, shaping capability, and reserve carrying capability of the projects.

Q. Please describe the wind generation input data.

A. The Company uses wind site information from the project developers to estimate generation.

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

A. The data for firm wholesale sales and purchases are based on contracts to which the Company is a party. Each contract specifies the basis for 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 or a market index (such as California Oregon Border (COB), Mid-Columbia (Mid-C) or Palo Verde (PV)), or may be based on some type of formula. The long-term firm contracts are modeled individually, and the short-term firm contracts are grouped based on general delivery points. The contracts with flexibility are dispatched against hourly market prices so that they are optimized from the point of view of the holder of the call/put.

Q. Please describe the input data for wheeling expenses and transmission capability.

A. Firm wheeling expense is based on the wheeling expense for the twelve-month historic period ending June 2007, adjusted for known contract changes in the forecast period through twelve-months ending June 2009. Firm transmission rights between transmission areas in the GRID topology are based on the

Company's Merchant Function contracts with the Company's Transmission Function and contracts with other parties. The limited additional transmission to which the Company may have access is based on the experience of the Company's commercial and trading department. An example would be the day ahead firm transmission that the Company historically purchases on Path "C."

Q. Please describe the system balancing wholesale sales and purchase input assumptions.

A. The GRID model uses four liquid market points to balance and optimize the system. The four wholesale markets are at Mid-C, COB, Four Corners, and PV. The Mona market has also been incorporated to reflect the level of transactions the Company enters at this limited market. Subject to the constraints of the system and the economics of potential transactions, the model makes both system balancing sales and purchases at these markets. The input data regarding wholesale markets include market price and market size.

Q. What market prices are used in the net power cost calculation?

A. The market prices for the system balancing wholesale sales and purchases at four liquid markets are from the Company's September 30, 2007 Official Forward Price, shaped into hourly prices. While the Mona market prices were developed consistent with the Company's September 30, 2007 price curves, they are not part of the official curve due to the limited nature of the market and are highly confidential. The market price hourly scalars are developed by the Company's commercial and trading department based on historical hourly data since October 2003. Separate scalars are developed for on-peak and off-peak periods and for different market hubs to correspond to the categories of the monthly forward prices. Before the determination of the scalar, the historical hourly data are adjusted to synchronize the weekdays, weekends and holidays, and to remove extreme high and low historical prices. As such, the scalars represent the expected relative hourly price to the average price forecast for a month. The hourly prices for the test period are then calculated as the product of the scalar for the hour and the corresponding monthly price.

Normalization

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

A. For forecast test years, normalization of input data for the production costs model is primarily limited to hydro data:

- Owned and purchased hydroelectric generation is normalized by running the production cost model for each of the three different sets of hydro generation. The resultant three sets of thermal generation, system balancing sales and purchases, and hydroelectric generation are then averaged.
- As previously explained, normalized thermal availability is based on a four-year average.

Q. 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 normalization.

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, is 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 the need for thermal 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 have therefore adopted production cost analyses that simulate the operation of the entire system using historical water conditions, as being representative of what can reasonably be expected to occur under normal conditions.

VISTA Model

Q. What is the VISTA model?

A. The Company uses the VISTA Decision Support System (DSS) developed by Hatch Ltd (previously Synexus Global) as its hydro optimization model. The VISTA model is designed to maximize the value of the hydroelectric resources for ratemaking purposes by optimizing the operation of hydroelectric facilities against a projected stream of market prices. The market price used in the VISTA model are the same prices used to produce the net power costs, namely the Company's September 30, 2007 Official Forward Price Forecast.

VISTA uses an hourly linear program to define the system configuration and the environmental, political, and biological requirements for that system. The input to the VISTA model is historical stream flow data, plant/storage characteristics, license requirements, and market prices. The output of the VISTA model is the expected generation subject to the constraints described above.

Q. Does the Company's use of the VISTA model in this general rate case differ from its use in other Company activities?

A. No. The physical project data, constraint description, and historical stream flows used in the VISTA model in the preparation of hydro generation proposed for use in this filing are exactly the same data used by the Company's Integrated Resource Plan (IRP) process.

Q. Do other utilities use the VISTA DSS model?

A. The VISTA DSS model is used by a growing number of other energy companies all over the world including the Bonneville Power Administration (BPA).

Q. In previous cases, hydroelectric generation was normalized by using historical water data. Is that still true with the VISTA model?

A. Yes. The period of historical data varies by plant. As explained later in my testimony, the Mid-Columbia projects use seventy adjusted water years beginning with water year 1928/29. The Company's large plant data begins in the 1958-1963 range. The Company's small plant data begins in the 1978-1989 range.

Q. Please describe the VISTA model inputs.

A. The VISTA input data come from a variety of sources, which are separated into the following three groups: Company-owned plants without operable storage, Company-owned plants with operable storage, and Mid-Columbia contracts.

The Company owns a large number of small hydroelectric plants scattered across its system. These projects have no appreciable storage ponds and are operated as run-of-river projects; *i.e.*, flow in equals flow out. For these plants "normalized generation" is based on a statistical evaluation of historical generation adjusted for operational changes at the particular plant that are the result of new license constraints.

The Company's larger projects (Lewis River, Klamath River, and Umpqua River) have a range of possible generation that can be modified operationally by effective use of storage reservoirs. For these projects, the Company feeds the historical stream flow data through its optimization model, VISTA, to create a set of generation possibilities that reflect the current capability of the physical plant, the operating requirements of the current license agreements, as well as the current energy market price projections.

For the Lewis, Klamath and Umpqua Rivers, the historical stream flows used as inputs to the VISTA model are the flows that have been calculated and recorded by the Company at each of the projects. Generally, flows are developed using a simple continuity of water equation where Inflow = Outflow + Change in Storage.

For the Umpqua River in particular, the stream flow data was constructed by piecing together a variety of historical data sources. The U.S. Geological Survey gauge data at Copeland at the outflow of the entire project provides the only long term recorded flows for the Umpqua basin. Moving upstream data was developed by comparison to similar watersheds combined with the continuity of water equation, described above, to determine where in the basin flows originated. In the last three to five years the Company has installed a number of gauging stations, which will help improve the data quality.

The Company's Mid-Columbia energy is determined by using VISTA to optimize the operations of the six hydro electric facilities below the Chief Joseph dam. Estimates of Mid-Columbia generation are complicated by the fact that this section of the river is subject to river flows regulated by the many large projects that are located upstream. The Company's Mid-Columbia generation is based on the regulated stream resulting from 70 years of "modified" stream flow conditions as modeled by the Pacific Northwest Power Pool.

The modified stream flows are the flows developed by the Bonneville Power Administration by determining the natural stream flow for the period of record and then modifying the historical data to reflect the year-2000 level of irrigation and development in the Columbia basin. [*2000 Level Modified Stream flow, 1928-1999*; Bonneville Power Administration. May 2004.] These modified flows are used by Pacific Northwest Power Pool to model the operation (regulation) of the entire Columbia Basin as it exists today. There are many variations of the Columbia River operations model results. We are using the "PNCA Headwater Payments Regulation 2004-05" file, also known as "The 2005 70 year Reg" file, completed in July 2005 for hydro conditions that actually occurred for the period 1928 through 1997. Thus, the inflows to the Mid-Columbia projects are the result of extensive modeling that reflects the current operations and constraints of the Columbia River. These streamflow data are the most current information available to the Company and serve as an input to the VISTA model.

The modeled discharge of the Grand Coulee Reservoir becomes the source of inflow data to the Company's model of the Mid-Columbia River generation. As in the case of the Company's owned large plants, the energy production resulting from the set of streamflows is analyzed statistically to produce a set of probability curves or exceedence levels for each group/week. The results are defined as exceedence level statistics for each week.

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

A. Yes. Using the VISTA model, the input of hydro generation located in Utah and Southeast Idaho is calculated in the same manner as the Pacific Northwest hydro generation.

Q. Please describe the VISTA model's output.

A. The VISTA model calculates the probability of achieving a level of generation. The model output is expressed in terms of "exceedence" levels. Each exceedence level represents the probability of generation exceeding a given level of generation. The number of output exceedence levels is a user defined input parameter. While levels could be set anywhere PacifiCorp finds that 25-50-75 exceedence levels are consistently within the historical variability of hydro generation and are used by the Company's operations planning group in its studies. This filing also incorporates these exceedence levels for normalization.

GRID Model Outputs

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

A. These variables are:

- Dispatch of firm wholesale sales and purchase contracts;
- Dispatch of hydroelectric generation;
- Dispatch of wind generation
- Reserve requirement, both spinning and ready;
- Allocation of reserve requirement to generating units;
- The amount of thermal generation required; and
- System balancing wholesale sales and purchases.

Q. What reports does the study produce using the GRID model?

A. The major output from the GRID model is the net power cost report. Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy load hours and light load hours.

Q. Do you believe that the GRID model appropriately reflects the Company's operating relationship in the environment that it operates in?

A. Yes. The GRID model appropriately simulates the operation of the Company's system over a variety of streamflow conditions consistent with the Company's operation of the system including operating constraints and requirements.

Q. Please describe Exhibit RMP___(MTW-2).

A. This Exhibit 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 forecast period. The total shown on Line 11 represents the total future usage of resources during the forecast period to serve system load. Line 12 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 13 represents the Company's system load net of special sales.

Q. Please describe Exhibit RMP___(MTW-3).

A. This Exhibit lists the major sources of future peak generation capability for the Company's winter and summer peak loads and the Company's energy load for the forecast period.

Q. Does this conclude your direct testimony?

A. Yes.