Exhibit
UP&L__(RCD-1)

PacifiCorp
Exhibit UP&L _____(RCD-1)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Average Annual Growth Rates by Jurisdiction

July 2003

Average annual growth rates by Jurisdictions
From Calendar year 1993 to 2002

	Average % increase per year	
	Energy	**Customers**
Oregon	0.19%	1.60%
Washington	0.82%	1.10%
California	0.97%	0.90%
Utah	3.61%	2.99%
Idaho	1.61%	2.53%
Wyoming	-0.57%	0.91%

Average annual growth rates by Jurisdictions
From Calendar year 2000 to 2002

	Average % increase per year	
	Energy	**Customers**
Oregon	-3.90%	0.91%
Washington	-1.46%	0.61%
California	1.80%	0.97%
Utah	-0.37%	2.28%
Idaho	1.77%	2.00%
Wyoming	-0.54%	0.87%

Exhibit
UP&L__(RCD-2)

PacifiCorp
Exhibit UP&L _____(RCD-2)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

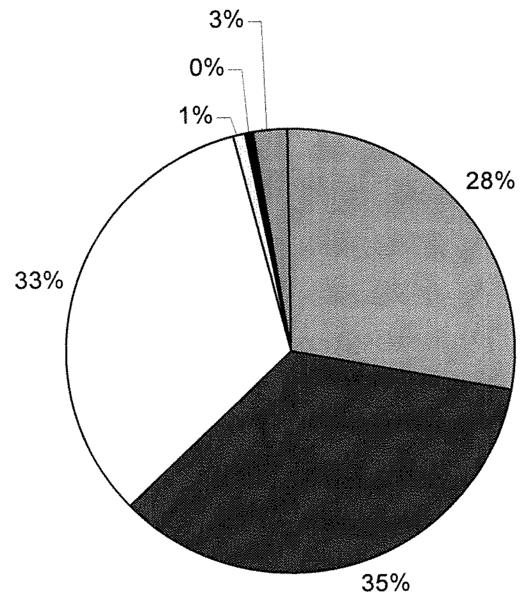
Exhibit Accompanying Direct Testimony of Reed C. Davis
Percentage of Total Sales and Percentage of Customers by Customer Class

July 2003

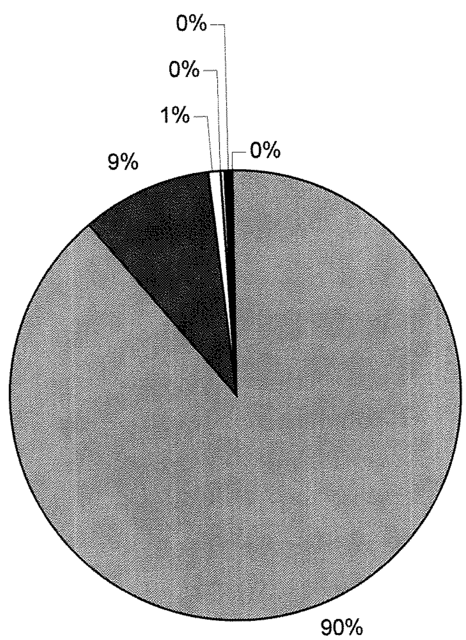
Exhibit 2

Residential Commercial Industrial Irrgiation PS&HWL OSPA

Contributon to Calendar 2002 Utah Energy Sales



Contribution to Average 2002 Utah Customers



PacifiCorp
Exhibit UP&L _____(RCD-3)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Average Annual Growth Rates by Customer Class

July 2003

Exhibit 3

Average annual growth rates for major customer class in Utah state
From Calendar year 1993 to 2002

	Average % increase per year	
	Energy	**Customers**
Residential	4.52%	2.99%
Commercial	6.39%	4.07%
Industrial	0.97%	-5.04%

PacifiCorp
Exhibit UP&L _____(RCD-4)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Average Annual Growth Rates by Geographic Location and Customer Class

July 2003

Exhibit 4

Utah State Average Annual Growth Rates by Geographic Location from 1993 to 2002

	Residential			Commercial			Industrial		
	Energy	Customer	Use/Cust	Energy	Customer	Use/Cust	Energy	Customer	Use/Cust
American Fork	6.12%	4.42%	1.70%	7.18%	6.55%	0.63%	-7.51%	-3.90%	-3.61%
Cedar City	5.84%	5.49%	0.36%	8.15%	3.38%	4.77%	4.47%	-0.78%	5.25%
Jordan Valley	6.61%	4.68%	1.93%	8.02%	4.02%	4.01%	3.44%	-8.87%	12.31%
Layton	6.09%	4.30%	1.79%	8.26%	5.26%	3.00%	0.79%	-7.53%	8.32%
Moab	3.16%	3.66%	-0.50%	5.73%	3.08%	2.65%	8.08%	-3.73%	11.81%
Ogden	4.13%	2.54%	1.59%	5.02%	2.88%	2.14%	3.99%	-4.94%	8.93%
Park City	7.21%	5.56%	1.65%	8.34%	6.37%	1.97%	1.36%	-3.38%	4.74%
Price	1.03%	1.53%	-0.50%	17.16%	3.03%	14.13%	8.09%	3.82%	4.27%
Richfield	1.70%	2.53%	-0.84%	5.31%	3.28%	2.03%	2.15%	1.05%	1.10%
Salt Lake	1.97%	0.55%	1.42%	4.39%	3.43%	0.96%	-0.49%	-3.61%	3.11%
Smithfield	3.67%	3.40%	0.26%	10.33%	4.90%	5.43%	0.59%	-1.27%	1.86%
Tooele	7.14%	5.65%	1.48%	7.14%	3.67%	3.47%	-1.95%	-1.97%	0.02%
Tremonton	2.75%	2.54%	0.21%	12.40%	1.91%	10.49%	1.63%	0.37%	1.26%
Vernal	1.77%	1.86%	-0.09%	4.47%	2.89%	1.58%	0.89%	0.59%	0.30%

Note: Shaded areas denote Wastach Front locations

PacifiCorp
Exhibit UP&L _____(RCD-5)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Recent Compared to Long-Term Growth Rates by Customer Class

July 2003

Exhibit 5

Average annual growth rates for major customer class in Utah state
Recent Growth rates compared to longer term

	Average % increase per year					
	Energy			Customers		
	1993-2002	**2000-2002**	**% chg**	**1993-2002**	**2000-2002**	
Residential	4.52%	3.39%	-25%	2.99%	2.16%	-28%
Commercial	6.39%	3.78%	-41%	4.07%	3.82%	-6%
Industrial	0.97%	-6.84%	-807%	-5.04%	-1.03%	-80%

Exhibit
UP&L__(RCD-6)

PacifiCorp
Exhibit UP&L _____(RCD-6)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Residential Average Use Per Customer

July 2003

Exhibit 6

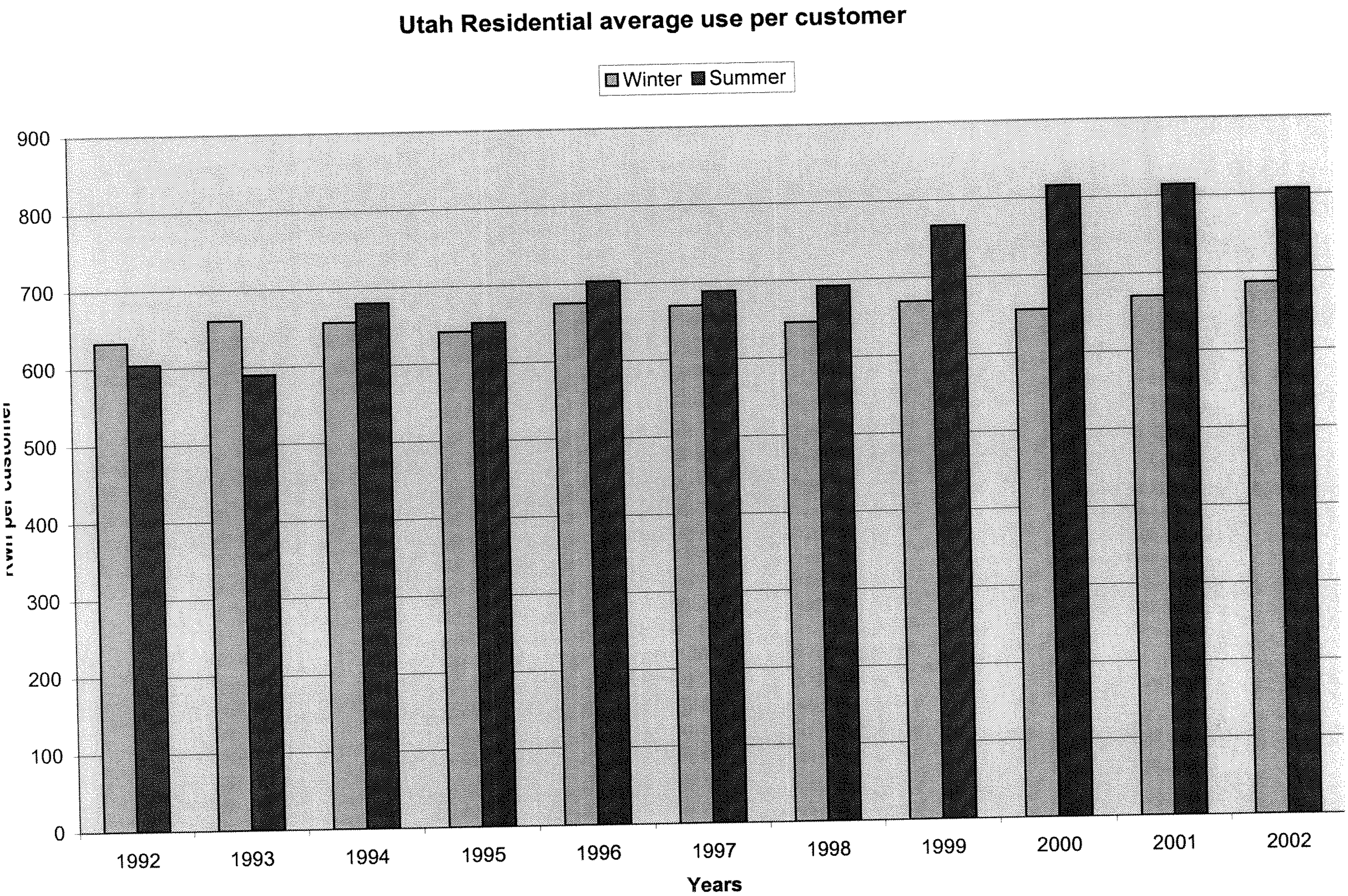

Utah Residential average use per customer
Winter
Summer
kWh per customer
900
800
700
600
500
400
300
200
100
0
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
Years

Exhibit
UP&L__(RCD-7)

PacifiCorp
Exhibit UP&L _____(RCD-7)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Commercial Customer Growth

July 2003

Exhibit 7

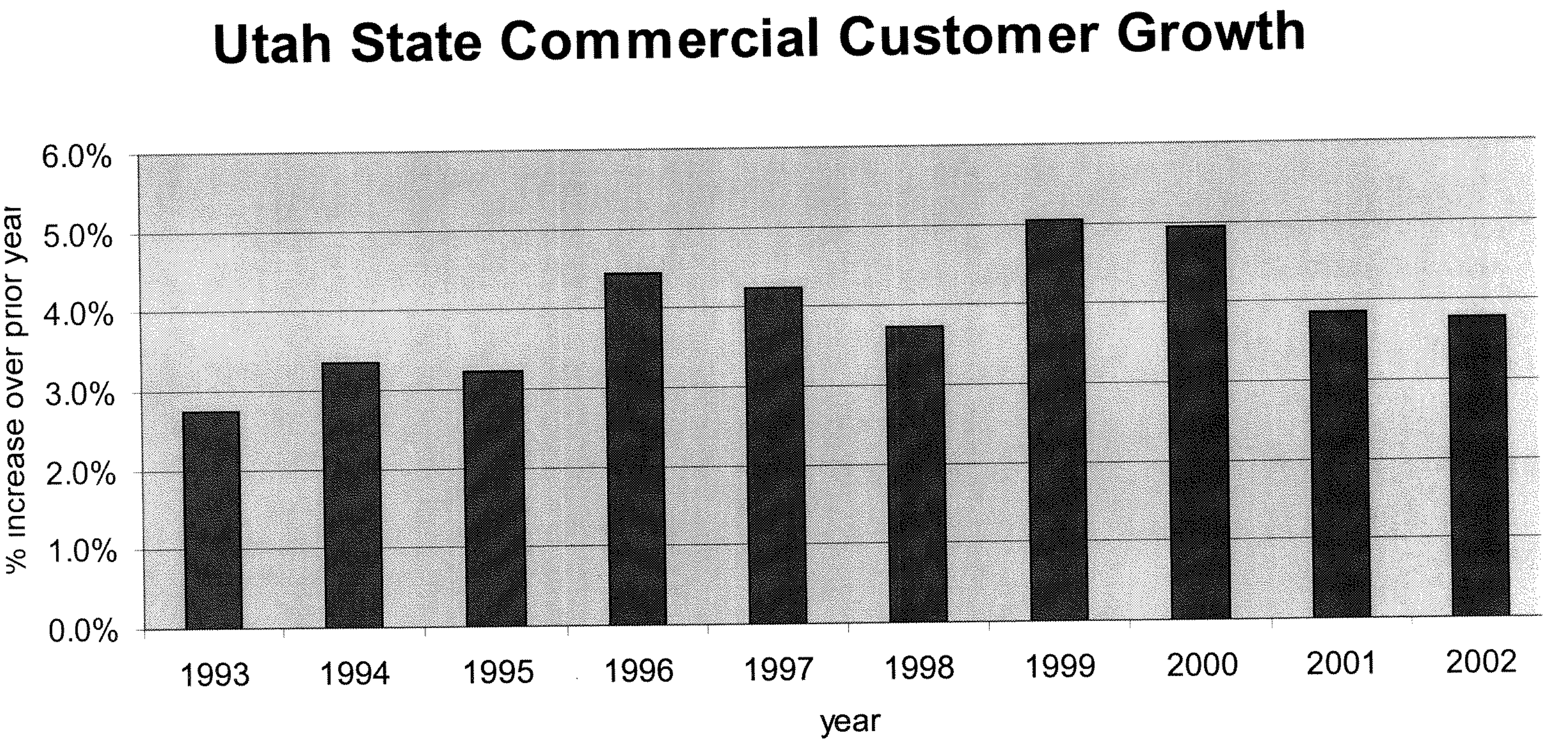

Utah State Commercial Customer Growth
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
% increase over prior year
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
year

Exhibit
UP&L__(RCD-8)

PacifiCorp
Exhibit UP&L _____(RCD-8)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Commercial Average Use per Customer

July 2003

PacifiCorp
Exhibit UP&L__(RCD-8)
Docket No. 03-2035-02
Witness: Reed C. Davis

Exhibit 8

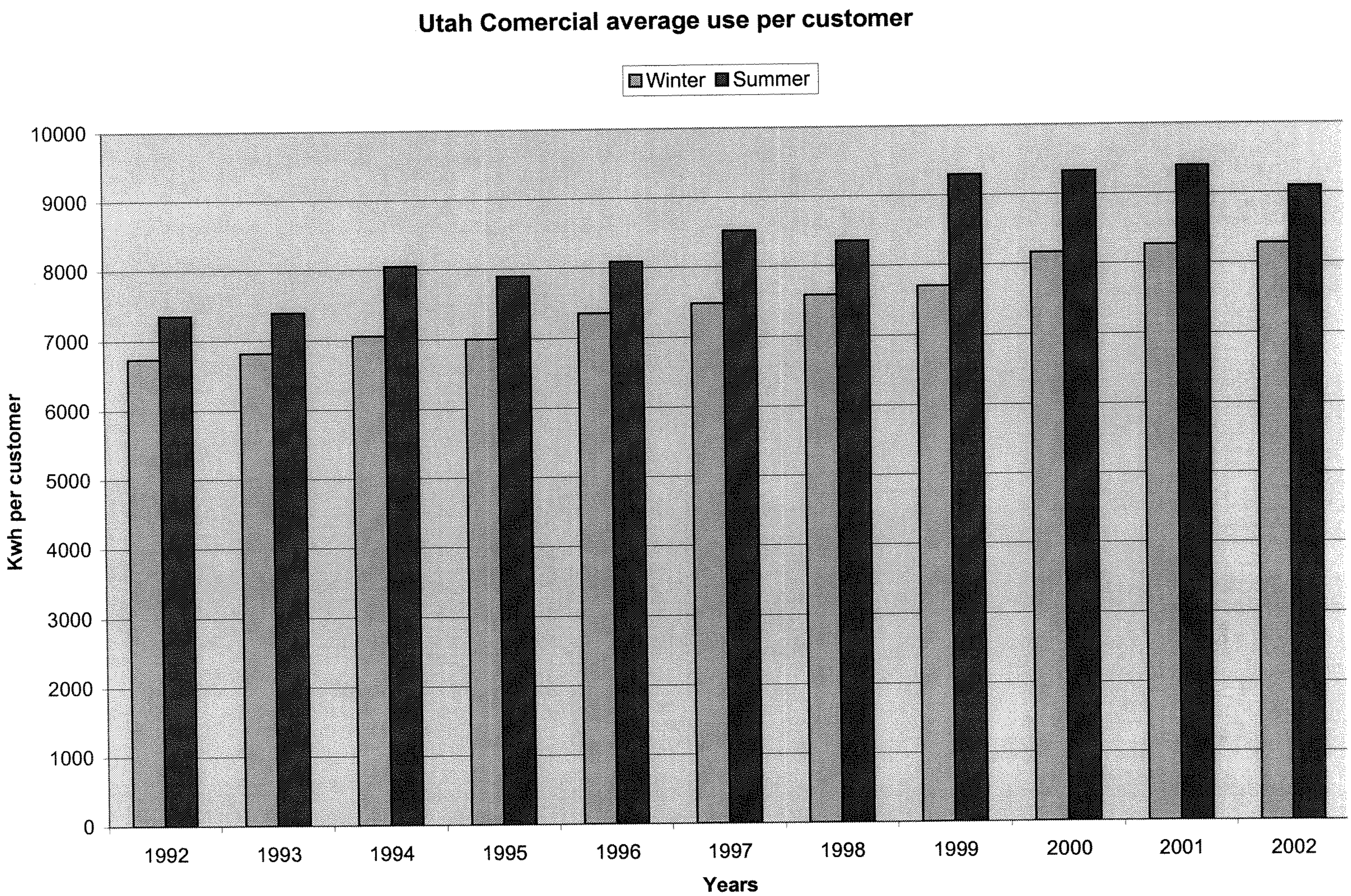


Exhibit
UP&L__(RCD-9)

PacifiCorp
Exhibit UP&L _____(RCD-9)
Docket No. 03-2035-02
Witness: Reed C. Davis

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

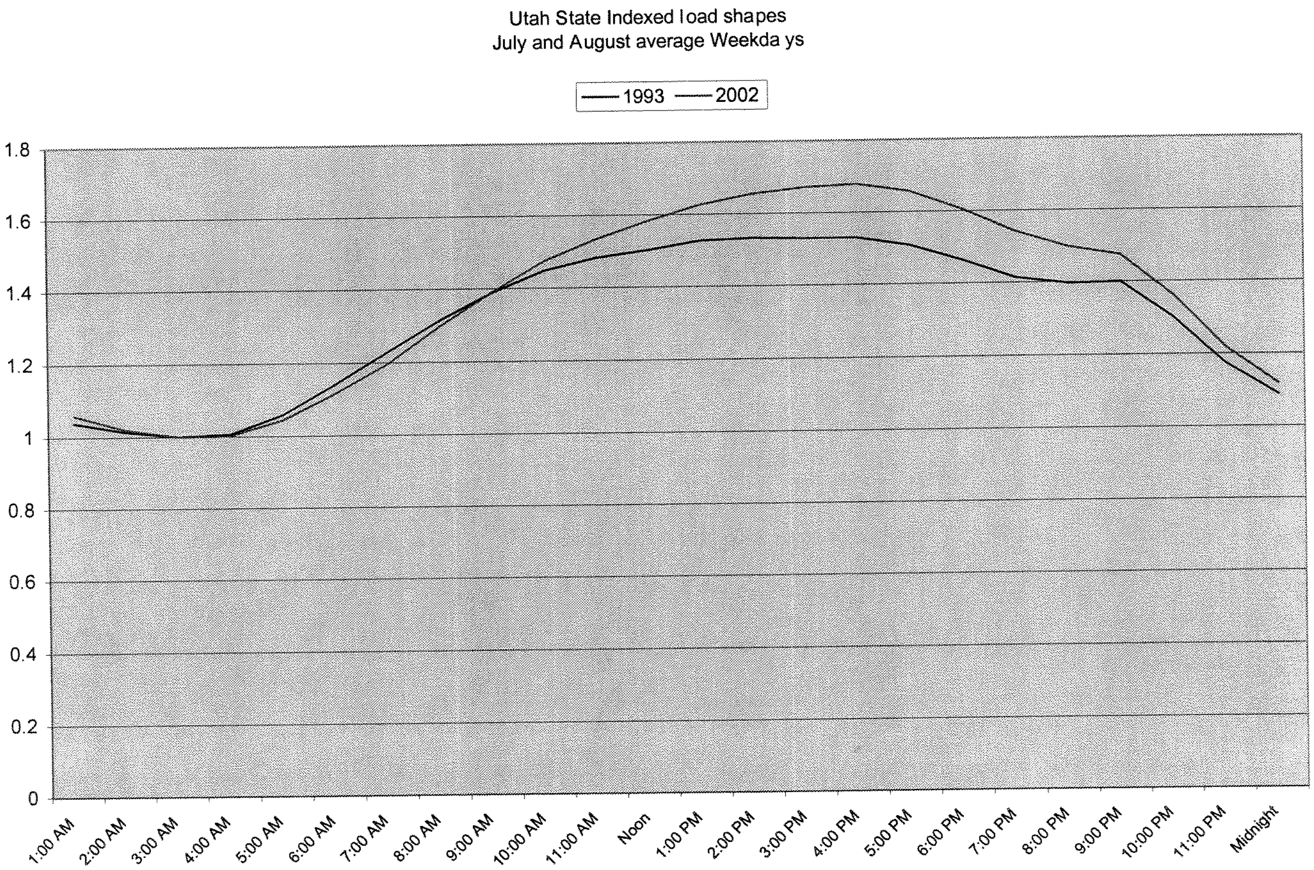
PACIFICORP

Exhibit Accompanying Direct Testimony of Reed C. Davis
Indexed Load Shapes, 1993 and 2002

July 2003

PacifiCorp
Exhibit UP&L__(RCD-9)
Docket No. 03-2035-02
Witness: Reed C. Davis

Exhibit 9



Testimony
Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES & ELECTRIC SERVICE REGULATIONS	))))))))	Docket No. 03-2035-02 DIRECT TESTIMONY OF MARK T. WIDMER

JULY 2003

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 Manager, Regulation.

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 PacifiCorp since 1980 and have held various positions in the power supply and regulatory areas. I was promoted to my present position in March 2001.

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 it is subject.

Summary of Testimony

Q. Please summarize your testimony.

A. I will present the normalized results of the production cost model study for the 12-month period ending December 31, 2003. I will describe the Company's production cost model, the Generation and Regulation Initiatives Decision Tools ("GRID") model, which is used to calculate net power costs. I will also provide information on how input data is normalized in GRID and the rationale for doing so.

Net Power Cost Results

Q. What are the results of the Company's normalized net power cost study?

A. Total Company normalized net power costs for the 12-month period ending December 31, 2003 are approximately $522.3 million.

Q. How does this compare with the level currently included in rates?

A. Net power costs are approximately $66.8 million lower than the $589.1 million included in base rates from the order in the Company's last Utah general rate case (Docket No. 01-035-01) ("2001 Rate Case"). This difference is due primarily to net system load being approximately 1.6 million MWh lower than the level included in the net power costs in rates.

Q. Why does a decrease in net system load result in a reduction in net power costs?

A. Lower retail loads decrease net power costs because the amount of energy that must be purchased from the market when the Company is short is reduced and the amount of energy available to be sold in the wholesale market when the Company is long is increased.

Q. Why has system load declined over the last three years?

A. The loads in the 2001 Rate Case were for the 12 months ended September 2000. Since that time, system wide loads have declined as a result of the general recession. Going forward, I expect the effects of the recession to ease, resulting in higher net system loads and net power costs.

Q. Would you describe the test period in this case?

A. Yes. The test period is 12 months ended March 31, 2003, normalized, as I describe later in my testimony, for the twelve month period ending December 2003.

Q. Were the Company's proposed net power costs prepared in a manner consistent with the previous orders?

A. Yes. In Docket 01-035-01, the Commission ordered the Company to impute SMUD revenue at $37 per MWh. This adjustment is included in the net power cost study. Also in Docket No. 99-035-01, the Commission ordered the Company to impute revenues on six wholesale contracts; all of these contracts have expired and are no longer included in net power costs.

Q. Does the thermal availability average include the Hunter No. 1 outage?

A. No. The effects of the Hunter 1 outage that started in November 2000 have been removed because the Company recovered the costs through the net power cost stipulation that was adopted by the Commission.

Q. Do the net power costs include the effects of the purchased power expenses incurred during the summer of 2002?

A. No. The summer 2002 forward purchase contracts have been excluded for the Company's net power cost study.

Determination of Net Power Cost

Q. Please explain 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.

Q. Were the proposed net power costs you sponsor in this case developed with the same production dispatch model used in the Company's last Utah filing?

A. No. The Company's proposed net power costs were developed using our new hourly production dispatch model, GRID 2.0.

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

A. The Company calculated net power costs on a normalized basis using the GRID model. The model simulates the operation of the power supply operations of the Company under a variety of stream flow conditions on an hourly basis. The results obtained from the various stream flow conditions were averaged and the appropriate cost data was applied to determine expected net power costs under normal stream flow and weather conditions for the test period.

Q. Please explain how GRID normalizes net power costs.

A. The development of expected net power costs begins with the selection of either a forecast or historic test period. I have divided the description of the power cost model into the following three sections:

1. The model used to calculate net power costs;
2. The model inputs; and
3. The model output.

The GRID Model

Q. Please describe the GRID model.

A. The GRID model is the Company's hourly production dispatch model, which the Company uses 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 exportable in Excel readable format; and
- A web browser-based user interface

Based on requests by regulatory staffs and intervenors, the model has also been modified to run on stand-alone personal computers.

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

A. Net power costs are calculated on an hourly basis 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, 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; and
   - Reserve requirement and allocation between hydro and thermal resources.
3. The model determines the following information in the Dispatch (optimization) process, based on resources pre-dispatched and contracts:
   - Optimal thermal generation levels, and fuel expenses;

- Expenses (revenues) of the 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; and
- 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 process 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 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 process provide thermal availability and system energy requirements for the Dispatch process?

A. Yes. Pre-dispatch, which occurs before the Dispatch process, calculates the availability of thermal generation, dispatches hydro generation, schedules firm wholesale contracts, and determines the reserve requirement of the Company's system. I will now describe each of the 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 process reads the input 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 and 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 process 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 process, the Company's available hydro generation from each non-run-of-river project is shaped and dispatched by hour within each month in order to maximize usage during peak load hours. The monthly shape of a non-run-of-river project is based on the hourly retail load and market prices in a month, and incorporates minimum and maximum flow for the project to account for environmental constraints. The dispatch of the generation is flat in all hours of the month for run-of-river projects. The hourly dispatched hydro generation is used in the Dispatch process 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 process?

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 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 six 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: the energy take of these contracts is tied to specific generators and is the same in all hours, which takes into consideration plant down time. There is no optionality in these contracts.
- Generator Optional: the energy take of these contracts is also tied to specific generators but is dispatched as generators with flexibility. They can be either hydro or thermal generation.
- Flat: these contracts have a fixed energy take in all hours of a period.
- Complex: the determination of energy take of these contracts requires the load and resource balances of the third party.

- No Energy: these contracts do not take energy. They are contracts for capacity transactions only.

In the Pre-dispatch process, 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 or short-term firm is entirely based on the length of its term. Consistent with previous treatment, the Company identifies long-term firm contracts by name and groups short-term firm contracts by general delivery points. If a short-term firm contract has flexibility as described for long-term firm contracts, it will be dispatched using the appropriate archetype. Conversely, if a long-term firm contract is a transaction for a standard block of energy, it will be dispatched the same way as standard short-term firm block transactions. Dispatched hourly contract energy takes are used in the Dispatch process to determine the energy requirements for thermal generation and system balancing transactions.

Reserve Requirement in Pre-Dispatch

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

A. The North American Electric Reliability Council ("NERC") requires all companies with generation to carry operating reserves of 5 percent for operating hydro resources and 7 percent for operating thermal resources. One-half of these reserves must be spinning. Spinning reserves are the amount of capacity that can be ramped up in 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.

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

A. The model calculates operating reserve requirements (both spinning and non-spinning) for the Company's east and west control areas, plus the regulating margin that is added to spinning reserve requirements. The total operating reserve requirement is 5 percent of dispatched hydro and 7 percent of committed available thermal resources for the hour, which includes both the Company's owned resources and the long-term firm purchase and sales contracts that contribute to the reserve requirement. Spinning reserve is one-half of the total reserve requirement plus the regulating margin, which is the same in nature as the spinning reserve but which is used for following changes in retail load from one hour to the next.

Q. How does the model satisfy reserve requirements?

A. Reserves are held first on hydro then on thermal units on a descending variable cost basis. Spinning reserve is satisfied before the non-spinning requirement. For each control area, the spinning reserve requirement is fulfilled using hydro resources and thermal units that are equipped with governor control. The non-spinning reserve requirement is fulfilled using remaining hydro reserves and thermal units. To better utilize the reserve capability of the Company's West-side hydro system, up to 175 MW of East-side reserves can be held in the West control region, of which 100 MW is spinning and 75 MW is non-spinning. The hourly reserve requirement allocated to the generating units is used in the Dispatch process to determine energy available from the resources and the level of the system balancing market transactions.

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

A. There is no impact on the hydro generation, since the amount of reserve allocated to hydro resources is based on the difference between their maximum technical capability and their available 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.

Model Inputs

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

A. As mentioned above, inputs used in GRID include retail loads, thermal plant data, hydroelectric generation data, firm wholesale sales, firm wholesale purchases, firm wheeling expenses, system balancing wholesale sales and purchases market data, and transmission constraints.

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

A. The retail load represents the temperature-adjusted hourly firm retail load that the Company served within all of its jurisdictions for the twelve-month period ending March 31, 2003. The total Company load is modeled based on the location of the load and transmission constraints between generation resources and 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 adjusted to remove extraordinary outages. 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 outages, maintenance 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 the 48 months ending March 2003. Other thermal plant data includes unit capacity, minimum generation level, minimum up and minimum down time, heat rate, fuel cost, and startup cost. The Company's use of a four-year average is consistent with the treatment authorized in Docket No. 01-035-01.

Q. Please describe the hydroelectric generation input data.

A. Fifty years of monthly available 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. The data are grouped by generation projects of each river system.

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 is calculated as the actual average monthly hydroelectric generation for the years 1974 through March 2003. 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. Does the Company use other hydro generation inputs?

A. Yes. The Company also uses maximum and minimum capacities of the projects, must-run level, and monthly shapes of the available energy.

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 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 California Oregon Border ("COB"), Mid

Columbia ("Mid C:), SP15 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 are dispatched against the hourly market prices so that they are optimized.

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

A. The data for firm wheeling are based on contracts to which the Company is a party. The firm transmission rights modeled in GRID are developed from the Company's OASIS for summer/winter postings. The limited additional transmission rights to which the Company may have access are based on the experience of the Company's Wholesale Energy Services Department.

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

A. The GRID model uses three wholesale markets to balance and optimize the system. The three markets are at Mid C, COB and Desert Southwest ("DSW"), where the model makes both system balancing sales and purchases if it is economical to do so under constraints. The input data regarding wholesale markets include market prices and sizes.

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 Mid-C, COB, DSW, and SP15 are based on actual Dow Jones prices for the period January 2003 through May 2003 and the Company's monthly Official Price Forecast for the period June 2003 through December 2003 shaped into hourly prices. The market price hourly scalars are developed by the Company's Commercial and Trading Department based on historical hourly data since April 1996. 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 price in 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 historical normalized test years.

A. For historical test years, normalization is the process of modifying actual test year data by removing known abnormalities and making adjustments for known changes. Normalization produces test year results that are representative of expected conditions. The following are examples of the normalization of actual test period results:

1. Owned and purchased hydroelectric generation is normalized by running the production cost model for each of the fifty different water years identified in the Hydro Regulation. The resultant fifty sets of thermal generation, non-firm sales and purchases, and hydroelectric generation are then averaged using a weighting method which accounts for 115 years of stream flow data as

measured on the Columbia River at The Dalles. As previously explained, normalized thermal availability is based on a four-year average adjusted for the Hunter 1 outage.

2. Wholesale market prices are adjusted to reflect expected prices during the normalized period.
3. Long-term firm wholesale sales and purchase contracts are redispatched based on the normalized wholesale market prices and known changes in the contracts.
4. Wheeling expense is adjusted for known contractual changes.
5. System load net of special sales is adjusted to reflect loads that would have occurred under normal temperature conditions.

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 have therefore 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:

- Dispatch of firm wholesale sales and purchase contracts;
- Dispatch of hydroelectric generation;
- Reserve requirement, both spinning and non-spinning;
- 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. Interim data that can be exported for more detailed analyses is also available, the format for which can be hourly, daily, weekly, monthly, annually and 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 in which it operates?

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

Q. Please describe Exhibit UP&L___(MTW-1).

A. This Exhibit is a schedule of the Company's major sources of energy supply by major source of supply for the test period, expressed in average megawatts owned and contracted for by the Company to meet system load requirements. The total shown on line 11 represents the total normalized usage of resources during the test 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 UP&L___(MTW-2).

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

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit
UP&L__(MTW-1)

PacifiCorp
Exhibit UP&L _____(MTW-1)
Docket No. 03-2035-02
Witness: Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer
Normalized Sources of Energy – 12 Months Ending December 31, 2003

July 2003

PacifiCorp
Normalized Sources of Energy
12 Months Ending December 31, 2003

Unit - Average Megawatts

Line No.	Description	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Line No.
	Company Owned Generation													
1	Hydro	710	785	669	541	468	453	387	334	354	469	721	759	1
2	Thermal /1	5,586	5,545	5,249	5,208	5,076	5,389	5,699	5,680	5,593	5,453	5,516	5,612	2
3	Wind	18	16	14	11	11	10	6	8	9	14	15	19	3
4	**Total Company Owned Generation**	**6,314**	**6,347**	**5,932**	**5,760**	**5,555**	**5,851**	**6,092**	**6,022**	**5,957**	**5,935**	**6,253**	**6,390**	4
	Purchased & Exchanges													
5	Long Term Firm	1,011	963	943	895	969	1,110	1,173	1,194	1,079	925	959	1,039	5
6	Mid Columbia	288	291	213	164	210	235	232	199	187	213	178	225	6
7	Exchanges	214	120	(41)	(47)	(174)	(61)	(68)	(212)	(215)	33	154	222	7
8	Short Term Firm Purchases	1,330	1,373	1,488	1,952	1,505	1,150	1,097	869	653	431	340	342	8
9	System Balancing	64	48	196	107	163	236	165	125	136	175	312	193	9
10	**Total Purchased Power and Exchange**	**2,908**	**2,796**	**2,799**	**3,071**	**2,673**	**2,670**	**2,598**	**2,175**	**1,841**	**1,777**	**1,943**	**2,022**	10
11	**Total Resources**	**9,223**	**9,142**	**8,731**	**8,831**	**8,228**	**8,521**	**8,690**	**8,197**	**7,797**	**7,712**	**8,196**	**8,412**	11
12	**Special Sales**	3,035	3,072	3,118	3,522	2,840	2,634	2,322	2,088	2,148	2,179	2,329	2,169	12
13	**System Net of Special Sales**	**6,188**	**6,070**	**5,614**	**5,309**	**5,389**	**5,887**	**6,368**	**6,109**	**5,650**	**5,534**	**5,867**	**6,243**	13

/1 Includes James River and Blundell Geothermal

Exhibit
UP&L__(MTW-2)

PacifiCorp
Exhibit UP&L _____(MTW-2)
Docket No. 03-2035-02
Witness: Mark T. Widmer

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer
Normalized Sources of Peak Capacity – 12 Months Ending December 31, 2003

July 2003

PacifiCorp
Exhibit UP&L ___ (MTW-2)
Docket No. 03-2035-02
Witness: Mark T. Widmer

PacifiCorp
Normalized Sources of Peak Capacity
12 Months Ending December 31, 2003

Line No.	Description	Winter Peak January MW	% of Total Capacity	Summer Peak July MW	% of Total Capacity	Annual Energy MWh	Annual Energy % of Total Requirement	Line No.
	Company Owned Generation							
1	Hydro	831	7.25%	593	5.55%	4,841,906	6.53%	1
2	Thermal /1, /2	6,266	54.69%	6,260	58.67%	47,891,569	64.55%	2
3	Wind	18	0.16%	6	0.05%	109,860	0.15%	3
4	**Total Company Owned Generation**	**7,116**	**62.10%**	**6,859**	**64.28%**	**52,843,336**	**71.22%**	4
	Purchased & Exchanges							
5	Long Term Firm	1,990	17.37%	2,332	21.86%	8,956,202	12.07%	5
6	Mid Columbia	331	2.89%	262	2.45%	1,921,760	2.59%	6
7	Exchanges	555	4.84%	(374)	-3.51%	(60,238)	-0.08%	7
8	Short Term Firm Purchases	1,407	12.27%	1,450	13.59%	9,124,931	12.30%	8
9	System Balancing	61	0.53%	143	1.34%	1,406,525	1.90%	9
10	**Total Purchased Power and Exchange**	**4,343**	**37.90%**	**3,812**	**35.72%**	**21,349,179**	**28.78%**	10
11	**Total Resources**	**11,459**	**100.00%**	**10,671**	**100.00%**	**74,192,515**	**100.00%**	11
12	**Special Sales**	3,785		2,872		22,926,000		12
13	**System Net of Special Sales**	**7,674**		**7,799**		**51,266,515**		13

/1 Includes James River
/2 After Derate, Maintenance and Reserve

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	
IN THE MATTER OF THE	)	Docket No. 03-2035-02
APPLICATION OF PACIFICORP	)	
FOR APPROVAL OF ITS	)	DIRECT TESTIMONY
PROPOSED ELECTRIC RATE	)	OF WILLIAM EAQUINTO
SCHEDULES & ELECTRIC	)	
SERVICE REGULATIONS	)	
	)	

JULY 2003

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

A. My name is William Eaquinto, my business address is 825 N.E. Multnomah, Suite 1500, Portland, Oregon 97232, and my present position is Vice President of Hydro Licensing.

Q. **Briefly describe your educational background, professional training and experience.**

A. I have been employed by PacifiCorp for 28 years and have held various line and staff positions throughout the company. I have served as Vice President of Licensing for the last 1½ years. I have a Bachelor of Science in Electronic Engineering Technology from Weber State University and hold current Professional Engineering Licenses in Electrical Engineering in Utah and Idaho.

Q. **What is the purpose of your testimony?**

A. My testimony explains the process for and the costs the Company incurred in obtaining new federal operating licenses for the North Umpqua, Bear River, and Bigfork hydroelectric projects. The Company initially pursued new federal licenses for the American Fork project and the Powerdale project, but after spending nearly five years in the licensing process, the Company decided that it would be more beneficial to PacifiCorp's ratepayers and shareholders to decommission the projects, after a period of continued operations, instead of relicensing. My testimony below explains why new FERC licenses would be more costly to the Company's ratepayers than decommissioning the projects, and why decommissioning is in the public interest. My testimony explains how relicensing the other three projects benefits PacifiCorp and its customers, and why it is in the public interest.

Q. Please describe how you have organized your testimony.

A. First, I briefly describe the North Umpqua, Bear River and Bigfork projects and the benefits customers have derived and will continue to derive from their operation and licensing. Second, I provide an overview of the federal process to obtain new operating licenses. Third, I describe the relicensing processes undertaken for the individual projects, including the American Fork and Powerdale projects. Fourth, I provide a summary of the costs and benefits of relicensing these projects. Finally, I describe the rationale behind the Company's decision to engage in Settlement Negotiations with licensing stakeholders to decommission the American Fork and Powerdale projects.

Overview of the Projects

Q. Please describe the projects.

A. The North Umpqua is a 185.5 megawatt hydroelectric project. It consists of eight developments, each with its own dam, waterway, penstock and powerhouse. In combination, the eight developments use three reservoirs and four forebays for water storage and over 37 miles of canals, flumes and penstocks to convey water throughout the project. The Company operates all eight developments under one FERC license (FERC No. 1927). The project is located on federal lands in the Umpqua National Forest. The project uses water from the North Umpqua River and two tributaries, the Clearwater River and Fish Creek.

The Bear River project consists of three developments: Soda, Grace-Cove, and Oneida. Each development includes a dam, reservoir, powerhouse, penstocks and waterways. Collectively, the developments generate 84.5 megawatts. The Company operates the projects under three separate licenses, FERC Nos. 20-019, 2401-007, and 472-017. The projects are located on the Bear River in southeastern Idaho on lands partially administered by the Bureau of Land Management.

The Bigfork project consists of one development with a diversion dam, intake structure and flowline, forebay, and penstocks feeding into a powerhouse. The Bigfork project operates under FERC license No. 2652-007. It is located on the Swan River in northwest Montana and has a capacity of 4.1 megawatts.

The American Fork project is located on American Fork Creek in Utah County, Utah near the City of American Fork. The project consists of a concrete diversion dam, a water conveyance system, a powerhouse, a turbine generator with a capacity of 950 kW, and a 12.5 kV distribution line.

The Powerdale project is located on the Hood River in Hood River County, Oregon. The project is operated as a run-of-river project, and consists of a concrete diversion dam 206 feet long and 10 feet high, a fish ladder leading to a federally-owned fish trapping and sorting facility, an intake structure, a water conveyance system, a powerhouse, a turbine generator, and appurtenant facilities.

Q. **Generally, what benefits do those projects provide PacifiCorp and its customers?**

A. Since their completion, the hydro projects have provided reliable power below market rates. The projects are a valuable source of power for peaking needs, system reserves, and load balancing. The projects are an important component of the company's "hydro-thermal" portfolio and are an integral part of the Company's current Integrated Resource Plan (IRP). The hydro projects individually and/or in aggregate, provide capacity and "shape" the energy output of the base-loaded thermal plants into higher valued heavy/peak load hours. This allows the thermal plants to operate at high capacity factors, increasing their efficiency while at the same time allowing the Company to minimize its need to acquire higher cost peaking energy. Unlike other sources of generation, hydro projects provide an additional environmental benefit because they are "emissions-free."

Overview of Federal Relicensing

Q. Please provide an overview of the federal relicensing process.

A. Under the Federal Power Act ("FPA"), the Federal Energy Regulatory Commission ("FERC") has the exclusive authority to license nonfederal hydropower projects on navigable waterways. Original licenses are issued for a term of 50 years, after which a licensee may seek relicensing. FERC issues subsequent licenses for a term of not less than 30 years or more than 50 years with FERC deciding the length of the license. FERC regulations require that a licensee file a Notice of Intent to apply for a new license five and a half years prior to license expiration. A licensee must file an application for a new license two years prior to expiration of an existing license. On average, licensing takes 8-10 years, and some applications have taken as long as 30 years. During the relicensing process, FERC typically allows projects to continue operating on annual license extensions under the same terms and conditions once the old license has expired.

The licensing process requires FERC to consider the economic, engineering, environmental, and socioeconomic aspects of the project. In issuing licenses, FERC must give "equal consideration" to environmental values and adequately protect and mitigate the effects of the project on environmental and other concerns. In doing so, FERC attaches conditions to the license.

Q. What role do State and Federal resource agencies play in the process?

A. State and federal fish and wildlife agencies review applications and submit comments to FERC regarding the impact of the project on the environment. Based on those impacts, State and Federal agencies recommend conditions to FERC to place on the license to mitigate the impacts. The FPA gives certain federal agencies the authority to require FERC to include the agency's conditions on the license. For example, the Secretaries of Commerce and the Interior have the authority to require applicants to install fishways (ladders and screens) at projects, and to require applicants to reduce variability of in-stream flows. Sometimes, the cost of complying with those mandatory conditions causes the project to be uneconomical.

Q. What options does an applicant have if the mandatory conditions make the project uneconomical?

A. The applicant has limited options. The applicant may either accept the uneconomic license, decommission the facility, or pursue litigation challenging the mandatory conditions. In states other than California, the applicant has the option of selling the plant as well. Because of the cost of replacing power for decommissioned or sold facilities and the uncertainty of litigation, those options are seldom favored. Consequently, applicants often try to avoid uneconomical licenses by settling issues among the various stakeholders before licensing is completed or attempt to negotiate acceptable decommissioning outcomes.

Q. Other than the FPA, what other laws must the FERC take into consideration when granting licenses?

A. Because licensing is a "federal action," FERC must evaluate the application under a host of federal laws: the Clean Water Act ("CWA"), the Coastal Zone Management Act, the National Environmental Policy Act ("NEPA"), the Endangered Species Act ("ESA"), the Fish and Wildlife Coordination Act, and the National Historic Preservation Act, among others.

Those additional laws can add time and expense to the application process. For example, before FERC can issue a license, an applicant must obtain certification from the state in which the project is located, that the applicant is meeting state water quality standards and criteria under Section 401 of the CWA. Similarly, under the ESA, FERC must consult with federal agencies to determine whether issuing a new license might jeopardize the existence of any endangered or threatened species or result in adverse modification of critical habitat.

The Company had to seek 401 approvals for all five projects. In addition, ESA considerations were present at all five projects because of the presence of endangered Coho salmon at the North Umpqua project, threatened bull trout, and threatened lower Columbia River steelhead and chinook salmon at the Powerdale project, threatened bull trout at the Bigfork project, and Bonneville cutthroat trout near the Bear River and American Fork projects.

Q. Does FERC offer more than one relicensing process?

A. Applicants currently may use either traditional or alternative licensing processes. Applicants may also enter into a negotiated settlement at any time. The Company initiated licensing under the traditional approach for each project, using settlement when appropriate.

Q. Please provide a more detailed description of the traditional FERC relicensing process.

A. The traditional process involves three stages of consultation. In the first stage the applicant distributes an Initial Consultation document, which explains the project and its operation and environmental setting to federal and state agencies, tribes, non-governmental organizations ("NGOs"), community interest groups and other stakeholders. Following the consultation document, the stakeholders meet and visit the site. Thirty days after the meeting, comments and additional study recommendations are due to the applicant. Stage one ends when a set of resource-by-resource study plans and stakeholder consultation documentation have been completed and provided to FERC.

In the second stage, the applicant conducts the proposed studies and prepares a draft license application, which it distributes to FERC and to interested agencies, tribes and stakeholders for review and comment. At this stage, agencies routinely request additional studies, which can be costly and time-consuming. The applicant may refer such requests to FERC for dispute resolution. At this stage, FERC may also request additional information. The applicant must provide FERC with a written summary of how the Company resolved any disagreements with agencies and others. The second stage ends when FERC accepts a final application for filing.

In stage three, FERC solicits initial comments and preliminary terms and conditions from resource agencies, tribes, and stakeholders, and gives notices the project is ready for environmental analysis under NEPA. At this stage, FERC may require additional information from the applicant to address those comments. FERC next initiates its detailed environmental and engineering review and solicits final comments, recommendations, terms and conditions, and mandatory prescriptions. FERC then prepares an Environmental Assessment or Environmental Impact Statement taking into account comments, responses and conditions.

Ultimately, FERC issues a license order describing both how the project will be operated during the next license term, and what environmental and other enhancement obligations the licensee must fulfill. Those obligations include the mandatory terms and conditions provided by the Secretaries of Commerce, Agriculture and Interior. In addition, if relevant, FERC appends any conditions associated with 401 water quality certification.

North Umpqua, Bear River, Bigfork, American Fork, and Powerdale Relicensing

Q. Please describe the relicensing and settlement process for the North Umpqua project.

A. PacifiCorp filed a Notice of Intent to relicense on December 18, 1991, and issued its First Stage Consultation Document on May 29, 1992. The Company submitted a license application in 1995. The original FERC license expired in 1997 and annual licenses have been issued to-date.

In late 1995, because of numerous requests for additional studies, and implementation of the Northwest Forest Plan – which created new and additional standards – the Company undertook a collaborative watershed analysis with the Forest Service and other stakeholders. This effort was completed in March 1998 and settlement negotiations were initiated in lieu of continuing with a FERC traditional approach.

The first round of negotiations proved unsuccessful. PacifiCorp exited them in November 1999 because of a dispute over the removal of Soda Springs dam, the re-regulating dam for the entire project. At FERC's direction, the company submitted an Addendum to its license application on February 21, 2000. Following the submittal of the Addendum, PacifiCorp and all parties in the proceeding petitioned FERC to abey the proceeding to allow settlement negotiations to reinitiate, and on May 17, 2000 FERC upheld the parties' request.

Since settlement had not yet been reached, in November 2000, FERC initiated its environmental NEPA analysis requesting agency terms and conditions, thus forcing the parties to participate in negotiations and meet FERC traditional requirements simultaneously.

In March 2001, as required by state law, the Oregon Fish and Wildlife Commission and the Company negotiated a Memorandum of Understanding ("MOU") regarding wildlife mitigation measures. As an alternative to building ladders and screens, the MOU provided for more cost-effective habitat restoration downstream of the project. On June 13, 2001, PacifiCorp and the state and federal parties signed a Settlement Agreement ("Agreement"). The parties submitted the Agreement to FERC together with a required Explanatory Statement. On July 3, 2002, the Oregon Department of Environmental Quality issued a 401-water quality certification.

FERC issued a Final Environmental Impact Statement for the project during April 2003. Currently, it is waiting to receive final mandatory terms and conditions from the US Forest Service. After receiving the US Forest Service's conditions, FERC is expected to issue a license for the project in the latter part of 2003. I have provided a detailed chronology of key points in the relicensing of the North Umpqua project as Exhibit UP&L___(WE-1).

Q. Please describe the relicensing and settlement process for the Bear River projects.

A. Licensing commenced in 1996 employing the traditional FERC approach. In the summer of 1997, the Company conducted a consensus-building process called the collaborative "Delphi Approach" in an attempt to resolve potentially costly issues regarding instream flows related to project operations. We did not reach agreement with the parties, however. The Company submitted a final license application on September 27, 1999. The Company responded to two AIRs in 2000 and 2001. Based on communications with agency stakeholders and the content of the AIRs, the Company concluded that agencies with the authority to prescribe mandatory conditions would likely require costly mandatory mitigation measures.

In November 2001, the Company convened a meeting of the agencies to discuss developing a MOU as a basis for settlement. Settlement negotiations began December 2001 and the parties signed a Settlement Agreement ("Agreement") in August 2002. The Agreement provided for mitigation measures that were less costly for PacifiCorp than the in-stream and fish passage recommendations originally proposed by the agencies and stakeholders.

PacifiCorp submitted a formal Offer of Settlement to FERC with supporting documentation in September 2002. In November 2002, FERC issued a draft EIS. PacifiCorp and stakeholders subsequently provided coordinated comments on the draft EIS that were consistent with the terms of the Agreement. The final EIS was issued in April 2003. The Idaho Department of Environmental Quality issued a 401 water quality certification consistent with the Agreement, which has been received by PacifiCorp and FERC. A detailed chronology of relicensing the Bear River projects is provided as Exhibit UP&L___(WE-2).

Q. **Please describe the relicensing and settlement process for the Bigfork project.**

A. PacifiCorp filed its Notice of Intent in August 1996. The Company filed its First Stage Consultation document in November 1997. Second stage consultation and studies occurred during 1998 and 1999, and the Company filed a draft license application in August 1999. The Company filed a final license application, and received Water Quality Certification from the Montana Department of Environmental Quality in August 2000.

The Company responded to two FERC AIRs issued in February 2001, relating to fish screen design and PacifiCorp's land ownership, water quality, and cultural resource management. The Company responded to the AIRs in April and June 2001. In August 2001, FERC requested consultation with the U. S. Fish and Wildlife Service ("USFWS") on several federally listed species in the project area. The consultation is occurring and USFWS is expected to file its required biological opinion with FERC in early summer of 2003.

The Company entered into negotiations with agencies and local interests to resolve issues relating to lands and recreation. The Company reached an agreement with all stakeholders and submitted the agreement to FERC for inclusion in its environmental analysis. FERC is expected to complete its environmental review and issue a license for the project sometime this summer.

Q. Please describe the relicensing and settlement process for the Powerdale project.

A. PacifiCorp initiated the relicensing process in February 1995 with the filing of the Notice of Intent with FERC. In March 1995 PacifiCorp filed its First Stage Consultation Document with FERC, and conducted Second Stage studies in1995 and 1996. At the time relicensing was begun, the project (including sunk costs) was only marginally economic; however, on a forward-looking basis, relicensing the project was the appropriate alternative so long as environmental protection measures required by relicensing were kept as low as possible.

PacifiCorp filed a license application in February 1998 with FERC. The original 38-year license expired in February 2000 and the project is currently operating under annual licenses from FERC. The application contained PacifiCorp's proposed measures to protect project-area affected resources over the term of a new license. These measures, when combined with additional measures recommended by FERC staff, and mandated by federal agencies (e.g., criteria fish screens), substantially impacted project economics. FERC conducted its NEPA analysis and issued a final environmental assessment in December 2001, and was poised to issue a license for the project.

Based on PacifiCorp's economic analysis of both projected capital expenses necessary to keep the project operating for the next 30-plus years (e.g., replacing the wood-stave flow line with steel), and the measures noted above, PacifiCorp determined that it would be in the best interest of our ratepayers and shareholders to decommission the project, rather than accept a new operating license.

In February 2002, PacifiCorp requested FERC suspend the Powerdale licensing proceeding to allow the Company time to prepare a decommissioning plan and to consult with key agencies and stakeholders on dam removal and other issues related to decommissioning.

In July 2002, in response to stakeholder requests, the company initiated decommissioning settlement negotiations. PacifiCorp and the settlement parties completed a Settlement Agreement in early June 2003 that provides for an additional seven years of project operations (through 2010) subject to several measures intended to protect environmental and recreational values in the project area during the interim period, followed by decommissioning from 2010- 2012.

The parties signed and filed with FERC the Settlement Agreement, Decommissioning Plan and other supporting documentation, on June 13, 2003.

Q. Please describe the relicensing and settlement process for the American Fork project.

A. PacifiCorp initiated the relicensing process for the American Fork project in 1995 and filed a license application on October 27, 1998. During relicensing studies and in comments on the license application, agency stakeholders, in particular the U.S. Forest Service and National Park Service who possess mandatory conditioning authority under the FPA, requested that the company construct a new flowline in a different location or decommission the project. (The flowline is located entirely on Forest Service and Park Service lands). This request was in addition to requirements for increased bypass flows for a native fish species, the Bonneville cutthroat trout. The cost to replace and relocate the flowline alone was nearly twice the cost of project decommissioning. Based on PacifiCorp's economic analysis of both projected capital expenses necessary to keep the project operating for the next license period, and the measures noted above, PacifiCorp determined that it would be in the best interest of our ratepayers and shareholders to decommission the project, following a period of continued operations, rather than pursue such an operating license.

PacifiCorp developed a proposal for project removal in late 2000 and submitted it for comment to agency stakeholders. Additional discussions with stakeholders were conducted throughout 2001 and 2002 regarding measures necessary in a settlement agreement for project decommissioning. The stakeholders focused on those elements of the project to be removed and the associated removal methods, schedule, and work practices that could be employed in the National Forest System Lands and Monument Lands on which the project is located.

PacifiCorp submitted a decommissioning proposal to FERC on December 30, 2002, and a formal Offer of Settlement on February 14, 2003. The Parties to the Agreement agreed that project removal would begin in September 2006, with hydroelectric power generation continuing until that time. Project removal would be complete by December 2007.

Q. Please explain why the North Umpqua licensing process has taken longer than the other projects.

A. The North Umpqua project is far more complex than the other projects, or for that matter, most hydroelectric projects. Relicensing the North Umpqua project was akin to developing eight separate license applications and 401 permit certifications – not just one. Studies had to be undertaken addressing the project's environmental impacts for each and every development, and numerous water quality, flow, reservoir and lake studies were conducted, among other required project impact and environmental analysis and studies.

In addition, the overall licensing process itself was extremely complex. It involved two rounds of settlement negotiations, and FERC reinitiated its traditional process during the second round of negotiations. Because of its size and potential impact on the environment, the project required additional state involvement to meet statutory requirements, and consultation requirements for coho and other listed terrestrial species under the Endangered Species Act. The State 401-certification process could not be completed until a settlement had been reached. All those processes contributed to the length and cost of the overall licensing process.

Q. Are there other factors that contributed to the length of the North Umpqua relicensing process?

A. Yes. The North Umpqua is located entirely on federal USDA Forest Service lands. This gave the Forest Service, through its 4(e) mandatory conditioning authorities, an important and influential role in the licensing process. In addition, its location caused the project to be subject to the Northwest Forest Plan, which triggered an additional requirement to undertake a comprehensive watershed analysis. That analysis required a multi-agency, multi-stakeholder process that reviewed the fisheries, water quality, geomorphology and terrestrial resources of nearly 1,000 square miles of the upper North Umpqua River basin, and resulted in a multi-volume report.

Although complicated, the watershed analysis created a more collaborative process between the Company and stakeholders and served as a "springboard" to initiate settlement discussions with the parties. Also, because of the analysis, the Forest Service and other parties agreed to withdraw requests for further costly AIRs that had been submitted to FERC, thereby allowing these requests to be addressed in a less costly, more efficient way.

Q. How does the amount of time the North Umpqua relicensing process took compare to other relicensing applications?

A. Despite all the complexities inherent with the North Umpqua project and relicensing process, the length of the process for that project is not out of the norm. According to National Hydropower Association data, the nationwide average for hydro project relicensing is 8 to 10 years, with many taking far longer to complete. The North Umpqua relicensing process has taken slightly more than eleven years. In my view, eleven years is a reasonable amount of time relative to what was accomplished: a collaborative settlement agreement, compliance with state laws, ESA compliance, compliance with FERC hydro license process up to final issuance, and 401 state water quality certification. Given the complexities associated with the North Umpqua project, the length of time, and costs for the relicensing, are prudent and reasonable.

Costs and Benefits of Relicensing

Q. Please describe how the licensing approach taken provided the best achievable outcome.

A. In each case, the Company considered decommissioning all or part of the projects at the time of relicensing and found that option to be a more expensive, less beneficial option for customers. In each application, the Company initially pursued traditional relicensing. However, after the Company submitted applications to FERC, the Company elected to engage in settlement negotiations to reduce further AIRs, avoid the potential imposition of high-cost mandatory conditions by the federal agencies, and to minimize the possibility of contentious litigation. Settlement negotiations provided an opportunity for the Company and stakeholders to craft many of the terms and conditions associated with the next FERC license, rather than relying on FERC to determine appropriate project operations and environmental enhancement measures. Doing so expedited the process, and resolved disputes that could have resulted in costly, time-consuming environmental studies. In sum, the settlement agreements led to new licenses with lower costs than those that would have been obtained through traditional means.

Q. What costs did the Company incur in the licensing processes?

A. At the end of the test period in this case (March 31, 2003), the North Umpqua project had accumulated $51.605 million on a system basis in relicensing process costs, the Bear River projects had accumulated $5.173 million, the Bigfork project had accumulated $585,000, the American Fork project had accumulated $463,000 and the Powerdale project had accumulated $4.470 million. A detailed cost breakdown for each of the five projects are provided as Exhibits UP&L___(WE-3) through UP&L___(WE-7).

Q. What is Utah's allocated share of these costs?

A. Utah allocated costs are $24.4 million of the total $62.3 million of costs on a system basis. The Utah revenue requirement change associated with these costs is $3.5 million.

Q Does the Company intend to propose known and measurable adjustments to these costs?

A. Yes. In our October 15 filing, we will update those costs to reflect changes that have occurred, or will occur on or before January 1, 2004.

Q. Because the North Umpqua costs are much greater than the other two projects, please break those costs down by major cost category.

A. The total North Umpqua relicensing process costs have accumulated since 1992 and on an annual basis have ranged from $6.9 million in 1993 as studies were completed and applications were developed, to $2.9 million in 1996 following submittal of the draft application to FERC.

Just over half the costs ($25.8 million) derive from outside services. These services included technical studies, watershed analysis, license application preparation, state MOU preparation, 401 applications costs, ESA consultation and documentation costs, legal, facilitator and mediator services, communications and other services.

Other direct costs such as material and company labor accounted for $3.0 million. Indirect costs accounted for 44 percent of the total cost ($22.7 million). Under the indirect cost category are various overheads such as materials, labor, printing and construction, totaling $4.8 million. In addition, property taxes total $1.1 million and Allowance for Funds Use During Construction ("AFUDC") total $16.8 million.

Q. Can you explain AFUDC and how the Company calculates it?

A. AFUDC is a generally accepted accounting treatment for regulated utilities that permits the capitalization rather than expensing of financing costs (i.e. interest) during the construction phase. This treatment relieves current customers from providing a return on investment for these financing costs during construction and shifts the responsibility to future customers who will receive the benefit of the completed facilities. The Company computes AFUDC by applying the AFUDC rate to qualifying Construction Work In Progress (CWIP) projects.

Q. What controls has the Company put in place to insure that the expenditures made in the relicensing process were required, necessary, and prudent?

A. First, the Company appoints a Project Manager for each relicensing project. The Project Manager works with department management to coordinate all efforts related to the process and project cost management. The Company also assembles a project team, which is comprised of technical leads who are subject matter experts in the various relicensing areas. Examples of technical leads include fishery and wildlife biologists, cultural and recreation technicians, etc. The team develops a relicensing strategy to address likely required studies and potential protection, mitigation, and enhancement ("PM&E") measures.

In addition, the Company has had a senior level officer oversight group, the Hydro Steering Committee ("HSC"), in place since the mid-1990's to provide oversight and direction on relicensing efforts. The HSC includes officers from regulation, legal, generation, finance and strategy. The HSC reviews and approves all aspects of the hydro relicensing approach, processes and associated costs. In addition, the HSC reviews all expenditures.

Finally, due to the fluid and multi-discipline nature of FERC relicensing process and the volatility associated with costs, the appropriate department and Office of General Counsel review all relicensing projects, as a whole, on an annual basis.

Q. Please explain how outside services costs have been managed?

A. First, an overall budget is established for the project spanning the time through expected license issuance. Each year, as part of the annual budgeting and approval process, the portion of the project budget to be expended in the upcoming year is thoroughly reviewed and approved by management. Throughout the year, a monthly break down of all project expenditures is provided to department management and to each of the Project Managers. This provides an opportunity to look at project costs on an overall basis and make adjustments as may be necessary to stay within the overall project budget if possible.

More specifically, as the Company prepares study plans, the technical leads are responsible for considering any existing data needs and potential data gaps. A study plan is then produced and the Company contracts with consultants to conduct the study. Consultants are generally selected through a formal bidding process unless specific expertise is needed. Oversight of consultant work is the responsibility of the internal technical team lead. Consultants provide monthly reports on their activities along with detailed invoices. Project Managers receive and review all invoices and review tasks each month.

Q. Please summarize your testimony.

A. PacifiCorp's hydro generation facilities comprise a critical component of its overall power supply portfolio. PacifiCorp's hydro resources provide reliable power at below market rates as well as valuable peaking energy, load-shaping, and system reserves. Owners of non-federal hydropower projects are required under the Federal Power Act to apply for new operating licenses from the Federal Energy Regulatory Commission.

Relicensing is a complex and often contentious regulatory process that takes many years to complete. The process requires consulting with multiple federal, state, tribal, environmental and community stakeholders; conducting and analyzing the results of numerous environmental studies; presenting and documenting the results of studies and consultation in license applications and other required documentation; and triggers compliance with other federal laws such as the Clean Water Act and Endangered Species Act. In order to operate hydro facilities and to preserve their unique benefits, licensees must seek new licenses and essentially "prove," through the relicensing process, that continuing to operate the project is still in the public interest. Federal agencies with mandatory conditioning authorities can force very high-cost licensing outcomes that FERC has no ability to question. Further, decommissioning is typically very high cost and generally not a viable option.

PacifiCorp initially approached relicensing the North Umpqua, Bear River, Bigfork, Powerdale, and American Fork projects using the traditional three-stage FERC consultation process. However, the Company initiated settlement negotiations, when appropriate, in all five proceedings to resolve disputes, expedite the processes, and achieve lower-cost results by avoiding potential litigation and removing uncertainty.

Q. Does this complete your testimony?

A. Yes.