**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 various other issues with intervenor and regulatory groups associated with the six state commissions that regulate the Company.

**Purpose of Testimony**

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

A. I will present the Company's estimate of Excess Net Power Costs for the 12-month period from June 1, 2002 through May 31, 2003 for which the Company is seeking deferrals in this proceeding (Deferral Period). I also present Net Power Cost projections for fiscal years 2003 through 2006 and explain why net power costs will continue to be substantially higher than the level assumed to be included in base rates.

**Estimate of Excess Net Power Costs**

**Q. Please explain how Excess Net Power Costs are calculated for purposes of the requested deferral.**

A. Excess Net Power Costs are determined on a monthly basis and are equal to the Actual Net Power Cost in dollars per MWh (ANPC) less the Base Net Power Cost in dollars per MWh (BNPC) multiplied by the Washington load deemed in rates.

**Q. Please explain how the BNPC is determined in Exhibit ___(MTW-1).**

A. BNPC represents the level of net power costs currently reflected in rates. Because the last Washington rate case, Docket No. UE-991832 (1999 Rate Case), was settled pursuant to the Rate Plan Stipulation, there was no specific finding regarding the level of net power costs reflected in base rates. For purposes of Base Net Power Cost, the Company is using the $486 million proposed level of net power costs as filed by the Company in the 1999 Rate Case. The BNPC is equal to the monthly net power cost, which consists of purchased power, wheeling and fuel expenses less special sales revenue, divided by the monthly net system load in rates. Exhibit ___(MTW-1) shows the components and calculation of the BNPC.

**Q. At the August 6 prehearing conference in this proceeding, counsel for Industrial Customers of Northwest Utilities (ICNU) raised the issue that using the $486 million figure as the baseline would fail to reflect the impact of the two 3 percent rate increases the Company has already received pursuant to the Rate Plan. (Tr. 51-52) Is this a legitimate issue?**

A. No. The Company's initial filing in the 1999 Rate Case sought an increase of

$25.8 million, or approximately 15 percent. The base rate increases provided under the Rate Plan, 3 percent in 2001, 3 percent in 2002 and 1 percent in 2003, are substantially less than what the Company requested in its initial filing in the 1999 Rate Case. As noted above, the $486 million the Company proposes to use for the baseline is the annual net power cost figure incorporated in the Company's $25.8 million rate increase request. ICNU's issue would be legitimate only if the relief granted under the Rate Plan approached the magnitude of the request originally sought by the Company in the 1999 Rate Case. Given that the increases under the Rate Plan are less than half of that requested, use of the $486 million figure as the baseline is very reasonable.

**Q. How is the monthly ANPC calculated?**

A. The ANPC is calculated based on the Company's actual monthly net power cost adjusted to incorporate the Commission-adopted Colstrip/Black Hills adjustment, to put the Fort James purchase power costs on the same basis as reflected in rates, and to exclude energy exchange contracts that have only nominal dollar values for accounting purposes. The resulting adjusted actual monthly net power cost is then divided by the actual monthly net system load to arrive at the ANPC.

**Q. ICNU's counsel also claimed during the prehearing conference that the Company's more recent use of a different power cost model (GRID) as compared to the PD Mac model used in estimating power costs in the 1999 Rate Case would affect the calculation of deferrals. (Tr. 52) Does this make a difference?**

A. No. Deferrals will be based on the difference between actual power costs and the baseline levels derived from the $486 million figure. The Company's subsequent adoption of the GRID model as the basis for future power cost projections has nothing to do with the calculation of deferrals in this proceeding.

**Q. Have you prepared an exhibit of the ANPC calculation for the Deferral Period?**

A. Yes. Exhibit ___(MTW-2) shows Actual and Forecast Net Power Costs for the Deferral Period on a monthly basis.

**Q. Please explain Exhibit ___(MTW-3).**

A. Exhibit ___(MTW-3) shows the calculation of estimated Excess Net Power Costs for the Deferral Period. This figure is calculated as the product of Washington load deemed in rates multiplied by the difference between ANPC and BNPC. As shown on Exhibit ___(MTW-3), we estimate that approximately $16.5 million of Excess Net Power Costs would be deferred during the Deferral Period.

**Q. How do you explain the higher level of power costs that the Company has incurred and will continue to incur during the Deferral Period?**

A. The Company, like other western utilities, was harmed by the power crisis in the western wholesale markets that began in May 2000. This situation was compounded during 2001 by abnormally poor hydro conditions in the 2000-2001 water year and the extended outage at the Company's Hunter 1 generating unit. The Company's losses were further compounded by the impact of unanticipated rule changes adopted by the Federal Energy Regulatory Commission, or FERC, in June 2001, and the resulting wholesale market price decreases that followed those rule changes. Some effects of the

2000-2001 power crisis continue to be reflected in the Company's costs during the Deferral Period.

**Q. Please explain why effects from the 2000-2001 western power crisis are included in costs during the Deferral Period.**

A. The Company's net power costs did not decline following the June 2001 FERC order implementing price mitigation measures throughout the West. Prior to June 2001, the Company had hedged against potential market price risk at prices much higher than the historical norm, but less than the then-current forward price curve, to cover the usually high resource requirements of the 2002 summer peak period. The impacts of these purchases are reflected in the net power costs during the Deferral Period.

**Q. How does the Company propose to account for the deferred power costs if its deferral request is approved?**

A. The Excess Net Power Costs each month would be credited to Account 557, thereby decreasing the recorded power supply expenses, and debiting Account 182.3. Deferred income taxes would be recorded by debiting Account 410.10, and crediting Account 283. The amortization of the balance in Account 182.3 would be accomplished by crediting Account 182.3 and debiting Account 557. Deferred income taxes would be amortized by debiting Account 283 and crediting Account 411.10.

**Q. Is the Company proposing to accrue carrying charges on its accrued Excess Net Power Costs?**

A. Yes. The Company proposes to accrue carrying charges on the unamortized balance at a rate of 8.80 percent, which is the rate included in the Third Supplemental Order for the 1999 Rate Case. The Company estimates the cumulative carrying charges through May 2003 to be approximately $1.0 million. The total deferred Excess Net Power Costs including carrying charges would be $17.5 million.

**Q. Has the Company received rate relief during this period in the other jurisdictions in which it operates?**

A. Yes. The Company has taken action in all of its other jurisdictions to recover the higher power costs arising from the dramatic increases in wholesale electricity prices in late spring 2000 and the related events thereafter. On November 1, 2000, the Company submitted requests for deferred accounting in Oregon, Utah, Wyoming and Idaho. These proceedings are in various stages.

- In Oregon (Docket UM 995), the Company was authorized to recover approximately $130 million in Excess Net Power Costs plus carrying charges over the amortization period. The Company has been recovering $22.8 million annually (a 3 percent increase) in rates since February 2001 and, in August 2002, this recovery level was increased to $45 million, or 6 percent.
- In Utah, the Company's request to defer Hunter 1 replacement power costs for future rate recovery was approved in February 2001 (Docket No. 01-035-23) and, pursuant to that authorization, the Company deferred about $104 million. The Company also filed on September 21, 2001 for approval to defer approximately $110 million of excess net power incurred during the period from May 9, 2001 (when Hunter 1 returned to service) through September 30, 2001. Pursuant to a Stipulation among the parties to the Utah proceeding, the Company will recover

about $147 million of the $214 million of Excess Net Power Costs, through a combination of measures including the continuation of a surcharge and offsets to the merger credit and Centralia credit.

- In Wyoming, the Company was authorized to defer Excess Net Power Costs commencing as of November 30, 2000 (Docket No. 20000-ER-00-160). To date, the Company has deferred approximately $93 million of Excess Net Power Costs. The Company filed a general rate case in April 2002 that will consolidate the recovery of all Excess Net Power Costs deferrals.
- In Idaho, the Commission in February 2001 authorized PacifiCorp to defer Excess Net Power Costs. The Company filed an application in January 2002 to begin recovering approximately $38 million of deferred costs in rates. Under a settlement reached by the parties to the Idaho proceeding, the Company would recover about $25 million of the $38 million deferred, through a two-year surcharge and an offset to the existing merger credit. It should be noted that the Company was prohibited from increasing general rates in Idaho prior to 2002 as a condition of approval of its merger with ScottishPower (Case No. PAC-E-99-1, Order No. 28213, p. 8) but, under the proposed settlement, would nonetheless be allowed partial recovery of Excess Net Power Costs incurred during a period prior to 2002.

**Net Power Cost Projections Fiscal Year 2004 through Fiscal Year 2006**

**Q. Does the Company expect net power cost levels to continue to be substantially higher than the $486 million level filed in the 1999 Rate Case?**

**A.** Yes. As shown on Exhibit **___**(MTW-4), **[Redacted].**

**Q. Please explain why net power costs are expected to stay at substantially higher levels during the remainder of the Rate Plan.**

A. Net Power costs are expected to stay at a substantially higher level for several reasons. The primary reasons include: the expiration of wholesale sales contracts; increased retail loads; the California Commission's denial of the Company's proposed sale of its California distribution property; and contractual cost increases for wheeling expenses, long-term firm purchases and coal and gas fuel expenses.

**Q. Please explain how the expiration of wholesales sales contracts and increased retail load have contributed to ongoing higher net power costs.**

A. Normally when wholesale sales contracts expire, resources are freed up which in turn can be used to make additional wholesale sales or reduce wholesale purchases, thereby keeping net power costs lower. However, in this instance, the Company timed the expiration of many of its wholesale sales contracts to coincide with additional retail load requirements. Consequently, the revenue credit from the recently expired wholesales contracts is gone because the freed-up resources are being used to meet higher retail load obligations, which don't provide a revenue credit to net power costs.

**Q. Could you provide an illustration?**

A. Yes. LTF wholesale sales volumes are expected to drop by approximately 5.3 MWh on an annual basis by the end of Fiscal Year 2006 compared to the 1999 Rate Case, while retail load is expected to have increased by approximately 6.0 million MWh. During this period the wholesale sales revenue credit from long-term firm sales is expected to drop by approximately $141 million.

**Q. Please explain how the lack of approval to sell the Company's California distribution property has contributed to higher ongoing net power costs.**

A. The Company's filing in the 1999 Rate Case included an adjustment to exclude approximately 976,000 MWh of retail load for California because of the expected sale. This adjustment had the effect of freeing up resources equivalent to the California retail load that were assumed to make additional wholesale sales and or reduce purchase power requirements, thereby reducing net power costs. Unfortunately, the Company has not been able to sell its California property and the 976,000 MWh of load savings and reduced net power costs have never materialized. Based on an average purchase price of $38 per MWh in Fiscal Year 2006, the incremental impact on ongoing net power costs is approximately $37 million.

**Q. Could you provide some examples of the contractual cost increases through 2006 you previously discussed?**

A. Yes. The Company has a long-term contract to procure gas for its Hermiston generation plant. The contractual price increase for that contract will increase the Company's thermal fuel expense by approximately $9.0 million. Contractual and market price increases for coal are expected to increase fuel expenses by approximately $7.0 million. Contractual price increases for the Company's Hermiston long-term firm purchase will increase net power costs by approximately $9.0 million.

**Q. Does the Company's forecast include activites that are expected to help reduce net power costs?**

A. Yes. The Company is always looking for opportunities to more economically serve its customers. For example, the Company plans to repower the Gadsby steam plants and invest in DSM activities. The repowering will convert the older, less-efficient 335 MW plant into an efficient 500 MW combined cycle combustion turbine. This change results in expected net power cost savings of approximately $42 million in Fiscal Year 2006. DSM investments are expected to result in net power cost reductions of approximately $8.0 million in Fiscal Year 2003 growing to approximately $16 million in Fiscal Year 2006.

**Q. Does this conclude your direct testimony?**

A. Yes.