BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA UTAH POWER & LIGHT COMPANY FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	) CASE NO. PAC-E-05-1)) Direct Testimony of J. Ted Weston))

PACIFICORP

CASE NO. PAC-E-05-1

January 2005

Q. Please state your name, business address and present position with PacifiCorp dba Utah Power & Light Company (the Company).

A. My name is Ted Weston. My business address is One Utah Center, Suite 2300, 201 South Main Street, Salt Lake City, Utah, 84140-2300. I am currently employed as the Manager of Revenue Requirement in the Regulation Department.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a Bachelor of Science Degree in Accounting from Utah State University in 1983. In addition to formal education, I have attended various educational, professional and electric industry related seminars during my career at the Company. I joined the Company in 1983, and I have held various accounting and regulatory positions prior to my current position.

Q. What are your current responsibilities?

A. My primary responsibilities are to calculate the Company's revenue requirement and regulated earnings, to determine the interjurisdictional cost allocations, and to explain those calculations to regulators in the six jurisdictions in which PacifiCorp operates.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company's results of operations for the test period based on Fiscal Year 2004 (FY04), which covers the twelve month period ended March 31, 2004. That period has been normalized to remove any non-recurring events and adjusted for known and measurable items to reflect a forward looking test period more closely aligned with the time when the new rates will be effective. My testimony presents evidence that based on these results of operations, PacifiCorp is earning an overall Return on Equity (ROE) in its Idaho jurisdictional service territory of 5.8 percent. This return is far below any other ROE recently authorized by the Commission for other investor-owned utilities in Idaho, and less than the ROE essential to provide a fair and equitable return for PacifiCorp's shareholders, as determined in Dr. Hadaway's testimony. In support of this conclusion, I introduce and describe the Company's Idaho Results of Operations Report, identified as Exhibit No. 9. In describing this report, I indicate the sources of the base data, describe certain normalizing adjustments to the base data, and explain the Company's forward looking approach for any known and measurable adjustments.

Q. Based on the results contained in Exhibit No. 9, what level of price increase is necessary for PacifiCorp to earn the ROE recommended by Dr. Hadaway?

A. A price increase of $16.9 million would be required to allow the Company the opportunity to earn the 11.125 percent ROE recommended in Dr. Hadaway's testimony.

Q. Is PacifiCorp actually seeking to increase revenues by $16.9 million in this proceeding?

A. No, the Company is requesting a price increase of $15.1 million based on the Revised Protocol stipulation. As explained in Mr. Dave Taylor's testimony and agreed upon as part of the Multi-State Process (MSP), the Revised Protocol stipulation imposes a limit on any increase to PacifiCorp's revenue requirement at

101.67 percent of the Idaho revenue requirement calculated under the Rolled-in Allocation methodology. The application of this rate mitigation cap limits the Company's requested rate increase to \$15.1 million, or \$1.8 million less than the increase that is supported by Exhibit No. 9. This cap is an effort to phase into the Revised Protocol method from Rolled-In over a five year period, as further discussed in Mr. Taylor's testimony.

Q. What is contained in Exhibit No. 9?

A. Exhibit No. 9 is PacifiCorp's Idaho Results of Operations Report ("Report"). The base year for the Report is fiscal year 2004, which has been normalized to present a forward looking twelve-month test period. The Report details revenues, expenses and rate base allocated to the Idaho service territory based on the Revised Protocol methodology, in accordance with the Revised Protocol stipulation described above. Mr. Taylor's testimony describes the changes in jurisdictional allocation methodology between Rolled-In and the Revised Protocol and the provision in the stipulation to phase into the Revised Protocol method. He also details the impacts of those changes on the Idaho revenue requirement.

Q. Please describe the contents of the Report.

A. The Report provides twelve-month totals for revenues and expenses. Rate base is calculated as the average of the beginning and end of year balances. The Report presents operating results for the period in terms of both return on rate base and ROE. Tab 1 of the Report provides summary information. Page 1.0 is a summary of results allocated to Idaho based on the Rolled-In methodology. Column 1 shows the adjusted Idaho results, and column 2 is the Rolled-In price change.

Column 3 adds this price increase to the adjusted general business revenues to get the Rolled-In revenue requirement. Column 4 reflects the application of the 101.67 percent cap required under the Revised Protocol stipulation. Column 5 is the product of columns 3 and 4 and represents the maximum allowed step increase to move to Revised Protocol. This maximum allowed amount was compared to the Revised Protocol revenue requirement (column 6) to demonstrate the impact of the cap (column 7). The final column is the price increase based on the capped Revised Protocol methodology carried forward from page 1.1.

Page 1.1 is a summary of the normalized Idaho results of operations for the test period with a calculation of the increase in Idaho retail revenues that would be necessary for the Company to earn 11.125 percent ROE based on Revised Protocol methodology. The Total Adjusted Results (Column 1) is carried forward from the results of operations summary, Page 2.2, and shows a forecasted ROE for Idaho of 5.8 percent. The Price Change (Column 2) shows that a price increase of $16.9 million in revenues is required to increase the return from 5.8 to 11.125 percent ROE in Idaho. Column 3 summarizes Idaho's revenue requirement. Page 1.2 supports the calculation of additional revenue-related taxes associated with the price change requested in column 2. Page 1.3 details the calculation of the net operating income percentage. Page 1.4 starts with Idaho unadjusted results and summarizes the impact of the normalization adjustments by type.

PacifiCorp summarizes adjustments into three different types. Type I adjustments represent base period accounting or Commission-ordered adjustments (i.e., reversing one- time write-offs). Type II adjustments typically annualize events that occurred during the base year (i.e., contract changes or wage increases). Type III adjustments reflect known and measurable events that occurred after the base period. Page 1.5 is a summary of all the normalizing adjustments by category contained in Tabs 3 through 8.

Tab 2 details the allocation of Company results to Idaho using the Revised Protocol allocation method. Pages 2.3 through 2.38 contain Total Company and Idaho-allocated revenues, expenses and rate base detailed by FERC Account. Tabs 3 through 8 summarize the normalizing adjustments by category made to FY04 base data to reflect on-going costs of the Company. Tab 9 is a replication of Tab 2 except the Idaho results are produced based on the Rolled-In allocation method. Supporting documentation for the data in Tab 9 is provided under Tabs B1 through B20, for unadjusted results. Tab 10 contains the calculation of the Revised Protocol allocation factors. This completes the summary explanation of the contents of my exhibit.

Revenues

Q. Would you describe the revenue normalization adjustments made in Tab 3, Revenue Adjustments?

A. Yes. Page 3.0 summarizes each adjustment in Tab 3, listing each in a separate column itemizing the impact to revenues, operation, maintenance, administrative and general expenses (OMAG), taxes, and rate base, and an overall impact to the ROE. The adjustments made to normalize the test year revenues are detailed on pages 3.1 through 3.7 with supporting documentation. I will briefly describe each of these adjustments.

Weather Normalization (Adjustment 3.1) – Adjustment 3.1 normalizes revenues in the base year by comparing actual loads to temperature normalized loads. Weather normalization reflects weather or temperature patterns which were measurably different than normal, as defined by using thirty year historical averages prepared by the National Oceanic & Atmospheric Administration. Only residential and commercial loads are considered weather sensitive. This revenue adjustment corresponds with the temperature adjustment made to the system peak and energy loads utilized for the development of the jurisdictional allocation factors.

Revenue Normalizing Adjustments – Adjustment 3.2 normalizes the base year revenues by removing items that should not be included to determine retail rates, such as credits from the Bonneville Power Administration (BPA) and ScottishPower merger credits. Also removed are Blue Sky revenues to assure that this program is not subsidized by non-participating customers; costs of the Blue Sky program are removed in the O&M section adjustment 4.2. This adjustment also removed the one-time change in unbilled revenues due to a change in the methodology used to determine the amount recorded on the balance sheet for unbilled revenues.

Rock River Warranty Reversal – Adjustment 3.3 removes a non-recurring settlement from base year results. PacifiCorp negotiated a warranty provision with the manufacturer as part of the installation contract of these wind generation units that guaranteed a specified completion date for the project. The contractor didn't meet the terms of the contract and paid the penalty determined by the contract.

Removal of System Balancing Activity – Adjustment 3.4 removes revenues recorded during the test period for wholesale sales to account 456. The Company models the normalized wholesale sales and purchase activities for net power costs in the Generation Resource Integrated Dispatch model (GRID). This adjustment in conjunction with adjustment 5.1 removes these net system balancing activities from the results and adjustment 5.1 replaces these with normalized amounts, as described in Mr. Mark Widmer's testimony.

USBR/UKRB Revenues – Adjustment 3.5 system allocates the cost of Klamath River water rights to better align them with the benefits of the hydro system. The U.S. Bureau of Reclamation (USBR) and the Klamath Basin Water Users' Protective Association (UKRB) receive a discounted tariff in exchange for their water rights through contracts with PacifiCorp. These contracts preserve the Company's interests in three hydro projects on the Klamath River. Because all customers share in the benefits of the hydro production from these plants, these costs should be shared in the same way.

Special Contract Reclassification – Adjustment 3.6 normalizes base year revenues by reversing the system allocation of special contract revenues and assigns those revenues to their home state. The Revised Protocol developed in MSP specified that these special contracts would be direct assigned to their home state. This means that the load associated with each of these contracts is included in its home state load for development of the allocation factors, with the revenues also being retained by the home state.

Little Mountain – Adjustment 3.7 removes excess revenue related to Little Mountain steam sales from months outside the test period.

This is a summary of normalization adjustments made to revenues, with the exception of the wholesale sales normalized by GRID summarized in adjustment 5.1

OMAG Expenses

Q. Please describe the adjustments made to base year OMAG expense in Tab 4 O&M Adjustments.

A. Tab 4 is a summary of the adjustments made to the Company's unadjusted FY04 OMAG expense to remove any non-recurring events as well as normalize the base year to more accurately reflect conditions during the rate effective period. Page 4.0 summarizes each adjustment in Tab 4, listing each in a separate column itemizing the impact to revenues, OMAG, taxes and rate base and an overall impact to ROE. The adjustments made to normalize the test year OMAG are detailed on pages 4.1 through 4.18 with supporting documentation. I will briefly describe each of these adjustments.

Uncollectible Expense – Adjustment 4.1 removes a joint owner accrual recorded during the base year to account for revenues billed to, but not paid by, the minority joint owner of the Company-owned generation facility. This dispute has since been resolved and is not considered a recurring event.

Blue Sky Program – Adjustment 4.2 removes the OMAG expenses associated with the Blue Sky program. The Blue Sky Program is designed to encourage voluntary customer participation in the acquisition and development of renewable resources. To ensure that non-participants do not subsidize this program, Adjustment 4.2 removes the expenses associated with the program from the base year expense. The retail revenues from program participants were removed from results in adjustment 3.2 and power purchases and sales were normalized in adjustment 5.1.

Miscellaneous General Expense – Adjustment 4.3 removes from the test period certain miscellaneous expenses such as club dues and other contributions that should have been charged below the line to non-regulated expense.

International Assignees – Adjustment 4.4 removes from the test period housing and other costs associated with international assignees who have either returned to Scotland or "localized" (transferred to the U.S. compensation package). The labor-related costs for those international assignees who returned to Scotland are removed in the labor adjustment 4.11 and 4.12. These are expenses that the Company does not expect to incur in the future.

DSM Liability Write-Off – Adjustment 4.5 removes a non-recurring liability write-off from the test period. Several years ago, PacifiCorp contracted for the development of some energy saving equipment for Oregon customers. In 2000 PacifiCorp sued for partial non-delivery and withheld payment from the contractor. Ultimately the Company lost this claim in arbitration, a settlement was later reached between the parties, and the Company wrote off the liability during the test period.

Customer Guarantee Reversal – Adjustment 4.6 removes customer guarantee payments from OMAG as these items should be booked below the line. ScottishPower made several customer guarantees as part of its merger commitments, and failure to comply with these guarantees resulted in fines to be paid to the customer. A review of the test period identified that some of the customer guarantee payments were incorrectly booked above the line.

Deferred Generation Asset Write-off Removal – Adjustment 4.7 removes from the base year the write-off of prior period preliminary survey and investigation costs. This accounting treatment is based on FASB Statement of Position (SOP) 81-1, Accounting for Performance of Construction-Type and Certain Production-Type Contracts, and SOP 98-5, Reporting on the Costs of Start-Up activities. These accounting pronouncements state that any project investigation and development costs incurred prior to receiving management approval should be expensed rather than deferred. In FY04, $5.4 million was expensed due to these pronouncements, and $4.3 million was incurred in prior years. Only the prior period amount was removed, leaving an annual amount of expense in the test period.

Remove Settlement Termination Expenses – Adjustment 4.8 removes the test year expenses associated with a potential legal liability accrued by the Company in connection with the termination of the failed sale of the California service territory. This is a one time, non-recurring event.

Direct Access Cost Removal – Adjustment 4.9 removes Oregon direct access costs from the test year. During FY04, an accounting entry transferring Oregon direct access costs from account 901 to 580 used two different locations: one

Oregon location, and the other a system location, which caused one side of the entry to be system-allocated rather than direct-assigned to Oregon. This adjustment corrects that allocation error.

Regulatory Asset Correction – Adjustment 4.10 removes a credit to expense created by an accounting error while writing off a contra account for the California FAS 109 regulatory asset. In September 2003, this contra account was written off by debiting account 1823109 and crediting account 930 for $19 million. During the same month another entry was made to reverse a second quarter adjustment for $4.6 million. Then in December an attempt was made to remove any impact of this entry from results by transferring it below the line to account 426. When the second entry was made, however, the full $19 million was transferred to account 426. This caused the test period expense to be understated by the $4.6 million.

General Wage Increase – Adjustments 4.11 and 4.12 annualize changes to wages and headcount that have occurred during FY04. PacifiCorp has several labor groups, both union and non-union, each with different effective contract renewal dates. These adjustments include several elements. First, there were several changes to employee levels, both new hires and employees no longer employed with the Company. In the case of new hires, their salaries have been annualized. In the case of those no longer employed by the Company, their salaries were removed. Second, the salaries and bonuses of the international assignees who have returned to Scotland have been removed along with adjustment 4.4, which removed their other benefits. Third, based on a weighted matrix of the Company's annual incentive goals, approximately 2.5 percent of the AIP payout was determined to be driven by the financial results of the Company and was removed. Fourth, social security and payroll taxes were adjusted to reflect the impact of these wage changes as well. The overall impact was an increase of salaries and payroll taxes of $6.1 million. The current OMAG Capitalization ratio is then applied, which assigns 76 percent to OMAG, and the net increase of $4.5 million is spread back to all OMAG accounts on the same ratio as they were originally charged

Proforma General Wage Increase – Adjustments 4.13 and 4.14 recognize that before this requested rate change is effective, an additional wage increase will also take effect. These increases are layered on from their effective date forward. (Adjustments 4.11 and 4.12 annualized wage increases that occurred during FY04.) Adjustments 4.13 and 4.14 have four elements: (1) salaries were increased prospectively from the date of their contract renewal dates, (2) we reflected the impact these wage increases will have on the annual incentive payout, (3) pension and benefits were normalized, and (4) the incremental impact of these changes to payroll taxes was calculated. Because incentive pay is affected by increases to base pay, we also escalated the incentive pay for these changes. In addition, as discussed in Mr. Dan Rosborough's testimony, although pension and post-retirement benefits total $44.8 million in FY04, the latest actuarial report indicates that before the rate effective date they will total $86.1 million. Additionally medical, dental, vision, and other employee benefits will increase by $15.4 million from FY04 levels. These increases have been included in this adjustment and spread back to each FERC account on the same ratio as labor. Mr. Rosborough's testimony discusses these cost increases as well. Finally, we reflected the incremental impact to payroll taxes for each of these items.

Scottish Power Cross Charge – Adjustment 4.15 reflects the impact of the cross charge agreement executed by PacifiCorp and Scottish Power UK (SPUK), which governs the allocation of costs incurred by each entity on behalf of the other. On September 30, 2003, the Company filed a Compliance Filing pursuant to the IPUC directives in the merger Order No. 28213 addressing conditions adopted regarding these affiliated interest transactions. The Securities and Exchange Commission authorized SPUK and its subsidiaries to bill PacifiCorp for corporate service costs incurred on behalf of PacifiCorp.

Q What is included within corporate costs?

A. Corporate costs include costs relating to executive management and corporate oversight provided to all ScottishPower plc divisions by SPUK and its subsidiaries. Similarly, costs incurred by PacifiCorp on behalf of SPUK will be cross charged to SPUK. All costs incurred by PacifiCorp for SPUK were charged below the line and are not included in the Company's revenue requirement application. Although SPUK has provided corporate services to PacifiCorp since the merger, cross charges began to be invoiced only as of April 2004.

Q. What measures are in place to ensure that these costs are reasonable in amount?

A. Both SPUK and PacifiCorp employ controls designed to ensure compliance with the corporate cross charge policy before payment is exchanged. Monthly financial meetings, which monitor levels of Group Corporate costs and any variances from amounts budgeted for a particular activity, are ongoing. Each quarter, PriceWaterhouseCoopers undertakes an external audit review of the Group Corporate financial records.

Q. Please quantify the cost categories included in Adjustment 4.15.

A. Adjustment 4.15 reflects the SPUK annual cross charge to PacifiCorp of $15,657,489 per year; Idaho's allocated share is $933,312. The cross charge is attributed to the following categories:

Corporate secretarial & shareholder services	$3.9 million
Executive Directors	$2.3 million
Group human resources	$2.1 million
Corporate finance	$3.8 million
Strategic planning	$1.3 million
Corporate Services (IT & Office Space)	$2.2 million
Total	$15.6 million

Q. How are the corporate costs allocated across the various entities?

A. The cross charge agreement provides that corporate costs are directly charged, directly allocated, or apportioned on a four-factor formula. Costs directly attributable to an affiliate will be directly charged. For example, external audit fees attributable to PacifiCorp, yet charged to SPUK, will be directly assigned. When direct charging is not applicable, the cost is evaluated for direct allocation. Direct allocation applies when a cost is based on a specific factor. For example, a cost based on personnel headcount would be directly allocated based on the headcount at each affiliate. The employee newsletter costs, for example, are directly allocated based on the number of employees at an affiliate. Common corporate costs that cannot be directly assigned or directly allocated are apportioned based on a four-factor formula. The four factors are sales, operating profit, net assets, and employee headcount. PacifiCorp believes the volume of sales, amount of assets, number of employees and profitability are reflective of the magnitude of common corporate resources required by the US and UK entities. These four factors are essentially the same as the traditional three factors PacifiCorp has used for a number of years, with the addition of a profitability measure. By including profitability as a factor in the allocation methodology, the entity that is relatively "light" on assets, yet profitable, will be allocated a larger share of corporate costs compared to the three-factor formula. About 41.4 percent of common corporate costs, such as corporate secretarial, group human resources, and group finance costs, are allocated to PacifiCorp on the four-factor formula.

Workers' Compensation Expense – With respect to Adjustment 4.16, the Company received notice that the Insurance Carrier used by the Company to provide employee Workers' Compensation insurance was in bankruptcy. The Company therefore set up a contingency reserve for $11.5 million in August 2003. Based on current actuarial studies, the reserve has been reduced by $5.9 million on the Company books to $5.6 million. Since it is not known whether this item will be covered by other insurers, this adjustment removes the expense side of both the establishment of the reserve and the write-off transactions from base year expenses.

Membership and Subscriptions – Adjustment 4.17 follows precedent established by the Commission for treatment of national and regional trade organizations. The Company has included 75 percent of dues paid to Pacific Northwest Utilities Conference Committee, Utility Air Regulatory Group, Edison Electric Institute, and Western Energy Institute and removed all other membership dues from results.

Irrigation DSM – Adjustment 4.18 corrects the allocation of payments made to Idaho irrigators. The load control payments were recorded to account 557, which is system allocated. By direct assigning these costs to Idaho, we have aligned the costs associated with the load reduction in Idaho with the benefit of lower loads. This reduction to load means a reduced amount of system costs gets allocated to Idaho.

Net Power Costs

Q. How are the Company's forecasted Net Power Costs (NPC) for the test period developed?

A. Mr. Mark T. Widmer's testimony describes how NPC is normalized for the test period. The NPC forecast normalizes steam and hydro power generation, fuel, purchased power, wheeling and sales for resale in a manner consistent with normalized operation of production facilities and the contractual terms of sales and purchase agreements. NPC is forecasted using the GRID model.

NPC Study – Adjustment 5.1 removes the actual net power costs incurred during FY04 and replaces those with the normalized results of the GRID model.

Trail Mountain Closure Amortization – Adjustment 5.2 relates to the Company's March 2001 closure of its Trail Mountain Mine, which supplied coal to the Hunter Plant (a jointly owned facility) and replaced that coal with lower cost coal from the Sufco contract.

Q. Will you explain what led to the Company's decision to close Trail Mountain?

A. Yes. When the Company acquired the Trail Mountain Mine from Arco in 1992, it was aware that acquisition of the Trail Mountain reserves provided the Company with access to the adjacent Cottonwood Lease. Production from Trail Mountain and Cottonwood leases would ensure a future supply of coal for the Hunter Plant. The Company first nominated the Cottonwood lease for bid in 1991. By 1998, however, PacifiCorp knew that the economically recoverable coal reserves at Trail Mountain were limited. In 1999, the Company began to consider other alternatives to pursuing the Cottonwood coal reserves and producing its own coal, and issued a request for proposal from outside suppliers. PacifiCorp's long term fueling strategy called for the Company to move into adjacent Cottonwood coal reserves and to continue to produce its own coal, a fact that the other producers in the area knew. At the time PacifiCorp issued its request for proposal, Utah's coal production was about 25 million tons annually, with the Company producing around 8 million tons, or 32 percent of the total production. The Company's mines have long provided the Company with leverage in the Utah coal market and on coal prices. Coal suppliers knew that for their bids to be successful, they would have to be superior to the Company's own cost of production. As a result, the Company was able to negotiate a very favorable five-year contract with an outside supplier. This contract provided an economic justification to cease further environmental permitting of the Cottonwood lease and to close the Trail

Mountain Mine.

Q. How have customers benefited from the Trail Mountain Closure?

A. Customers are receiving annual fuel savings of over $19 million a year under the new coal purchase contract compared to continued operation of Trail Mountain. Even with a five-year amortization of the closure cost and including a carrying charge on the un-recovered plant investment, customers still receive a net benefit of over $7 million annually.

Q. How is the Company accounting for these closure costs?

A. A petition for a deferred accounting order allowing deferral of the Trail Mountain un-recovered investment was filed with the Idaho Commission on February 8, 2001. This application was approved in Order No. 28700 issued April 5, 2001. The original application requested deferral of the un-recovered assets only and did not take into account the additional costs associated with closing the mine. Closure costs were an additional $19 million which was also deferred. In April 2002, two regulatory assets totaling $46 million were recorded on the Company's books, one for the Trail Mountain Closure costs and the other for the un-recovered Trail Mountain Investment. These regulatory assets are being amortized over a five-year period. The amortization expense is recorded in Account 501, Fuel Expense. However, because this amortization includes the joint owners' share, we removed it from the normalized fuel costs included in Adjustment 5.1, Net Power Cost study, and added only PacifiCorp's share of twelve months amortization expense of $7,935,023. This adjustment also removes the $1,194,806 of joint-owner payments to PacifiCorp from Account

456, because the joint owners' share of amortization expense is not included.

In addition, because the regulatory assets include the joint owners' portion, it was necessary to correct the balance of the unamortized regulatory asset included in the test period. Adjustment 5.2 decreased the regulatory assets by $3,366,682, reflecting the appropriate regulatory asset balance of $19,808,687 in the adjusted test period.

BPA Regional Exchange Credit – Adjustment 5.3 removes the BPA credit from purchase power expense. The Company receives an annual amount from BPA to be passed on to its customers. This is accounted for by reducing power costs on the expense side and providing a credit to customer bills on the revenue side. Since this is a straight pass-through from BPA, it is not included in the determination of PacifiCorp's revenue requirement. The credit to revenues was removed in adjustment 3.2.

Depreciation and Amortization Expense

Q. Were there any adjustments to the actual depreciation expense?

A. Yes. The Company is adding the new Currant Creek generation facility, as described in Mr. Stan K.Watters' testimony. All components of this investment (with the exception of its impact on NPC) are summarized in adjustment 8.11.

Q. Have you included amortization expense for other miscellaneous items?

A. The actual results include amortization expense for other deferrals and regulatory assets included in Tab B16 of my exhibit.

Taxes

Q. Please describe the adjustments to taxes.

A. This section has four adjustments to income taxes and one to property taxes.

Interest True-Up – Adjustment 7.1 aligns interest expense with net rate base by applying the weighted cost of debt to Idaho net investment.

Deferred Tax Balance Reclass – Adjustment 7.2 is necessary to correct the allocation of two deferred tax balances. A review of these two accounts, which were being allocated on a SO factor, revealed they actually contained several state-specific regulatory assets which should be direct assigned to specific states or, alternatively, should be excluded from the revenue requirement calculation. For example, the deferred income taxes associated with the recovery of the excess power costs incurred during the Western power crisis were recorded in one account. These costs were recovered on a separate rider and should not be included in these results. The supporting work papers detail the components of each account and their correct allocation.

Wyoming Wind Tax Credit – Adjustment 7.3 recognizes that the federal government offered an income tax credit for investment in renewable resources placed into service before December 31, 2001. The Company owns 78.8 percent share of the Foote Creek wind project in Wyoming. The total Company tax credit of $2.2 million is based on PacifiCorp's share of the energy produced at that facility. This adjustment includes that tax credit in results.

Property Tax – Adjustment 7.4 aligns property taxes with the investment included in this filing. Property taxes are based on the plant investment as of

January 1 of each year. The property taxes in FY04 are based on plant balances as of December 31, 2002. This adjustment applies the imputed rates to the plant balance included in the filing.

IRS Settlement Amortization – Adjustment 7.5 amortizes payments made for state income taxes over five years. In FY04 PacifiCorp paid $634,571 to state taxing authorities as a result of the IRS settlement for years 1994 through 1998. The requested amortization of these payments over 5 years is consistent with the number of years to which the IRS settlement applies. This adjustment complies with the Stipulation in Case No. PAC-E-03-05 wherein the Company committed to propose a methodology for the recovery of future audit assessments

Rate Base

Q. Please describe each of the adjustments to rate base balances.

A. **Update Cash Working Capital** – Adjustment 8.1 aligns cash working capital with the operating expenses included in the filing. PacifiCorp utilizes a Lead / Lag study to account for the lag associated with providing electric service to customers. While there are several different methods used to calculate working capital, the Company believes cash working capital based on a Lead / Lag study is the most accurate. The Company updated its study based on fiscal year 2003 data

Environmental Settlement – Adjustment 8.2 deducts the unused insurance settlement for environmental clean-up sites from rate base. In 1996, the Company received an insurance settlement of $38 million to cover the cost of Company clean-up sites. These funds were transferred to PacifiCorp Environmental Remediation Company (PERCO), which is performing the clean-up at these sites.

As remediation work is performed on the clean-up sites, the funds from the insurance settlement are used, reducing the fund balance.

Trapper Mine – Adjustment 8.3 adds PacifiCorp's 21.4 percent interest in the Trapper Mine, which provides coal to the Craig Generating Plant, into rate base. The normalized coal cost of Trapper Mine includes all operating and maintenance costs but does not include a return on investment. It is necessary to add the Company's investment in Trapper Mine to rate base, since this investment is recorded on the Company's books in Account 123.1 - Investment in Subsidiary Company, which is not normally a rate base account.

Jim Bridger Mine – Adjustment 8.4 adds PacifiCorp's two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger Generating Plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. (PMI). Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. The normalized coal costs for Bridger Coal Company include the operating and maintenance costs of mining, but provide no return on investment. This adjustment is therefore necessary to properly reflect the Bridger Coal Company investment in base year rate base.

Plant Held for Future Use – Adjustment 8.5 removes Plant Held for Future Use from the beginning balance that was written off during the year. While the plant was not included in the ending balance, it was still on the books at the beginning of the year.

Correction of Weatherization Allocation – Adjustment 8.6 reverses the system allocation of weatherization loans. During the year, the Company received payment for some Utah DSM loans. These payments were incorrectly allocated on a system wide basis rather than directly to Utah, however, and this adjustment makes the necessary correction.

Hydro Relicensing Obligations – Adjustment 8.7 includes in rate base the net balance of the North Umpqua and Bear River FERC relicensing settlement obligations and associated amortization expense. During the FERC relicensing process, FERC required the Company to comply with several new requirements as a condition for approval of the new license. The North Umpqua agreement is for 35 years and Bear River is a 30 year agreement. FASB requires net present value accounting of these future obligations, creating a regulatory asset and offsetting liability on the Company's books. The Company proposes a straight-line amortization of these obligations. Whether there is a net asset or liability is based on the timing of obligation payments verses the straight line amortization of the asset. This amortization has two components, principal and interest. The principal is amortized to account 404. The Company has filed an accounting application requesting that the interest expense be recognized as an operating expense rather than interest for regulatory purposes.

Customer Advances – Adjustment 8.8 corrects balances that were recorded in the base period to a corporate location rather than state-specific locations. This adjustment corrects the allocation of customer deposits by situs assignment of those balances.

Sale of Naches – Adjustment 8.9 removes the net investment of the Naches hydroelectric facility that was sold in fiscal year 2005.

Sale of Skookumchuck – Adjustment 8.10 removes all effects of the Skookumchuck dam, gross plant, accumulated depreciation and deferred tax balances, depreciation and operating expenses from the base year results of operations. The project was sold because current generating costs to produce power at the Skookumchuck hydroelectric unit was extremely high and was no longer efficient for PacifiCorp to continue to operate. The Skookumchuck dam was constructed for the purpose of holding and storing water for the Centralia plant. Later the hydroelectric unit was added. The hydro dam and generating unit were not sold initially with the Centralia plant because a few counties had expressed interest in purchasing it. Since these counties no longer have the funds to purchase the dam and hydroelectric unit, the Company is in the process of selling Skookumchuck to Washington LLC, a limited liability Company formed by TransAlta USA, Inc., the same entity that purchased the Centralia plant.

Currant Creek Addition Phase I – Adjustment 8.11 adds the investment, depreciation, operating costs and property taxes into results.

Q. Does this conclude your description of rate base adjustments?

A. Yes.

Q. Would you describe the rest of the Report?

A. Yes. Tab 9, Rolled-In, is a re-cast of Tab 2 based on Rolled-In allocation. Tab 10, Allocation Factors, summarizes the derivation of the jurisdictional allocation factors using the MSP Revised Protocol allocation methodology. Mr. Taylor describes the derivation of these allocation factors in his testimony. Tabs B1 through B20 provide fiscal year 2004 unadjusted results by function. The Rolled-In allocation methodology was provided since the Company has not received approval from all jurisdictions to use Revised Protocol and hasn't yet made the programming changes to produce these reports.

Q. Does this conclude your direct testimony?

A. Yes.