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 responsibilities?

A. My primary responsibilities are to calculate the Company's revenue requirement, regulated earnings, 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 twelve month future test period ended March 31, 2006. (This future test year corresponds with the Company's Fiscal Year (FY) 2006.) My testimony presents evidence that, based on its forecasted results of operations for the twelve months ended March 2006; PacifiCorp is earning an overall return on equity (ROE) in its Utah jurisdictional service territory of 6.0 percent. This return is far below the 10.70 ROE authorized by this Commission in Docket No. 03-2035-02 and less than the ROE essential to provide a fair and equitable return for PacifiCorp's shareholders. An overall price increase of $123.6 million is required to produce the 11.125% ROE supported by Dr. Hadaway's testimony. In support of this conclusion, I introduce and describe the Company's Utah Results of Operations Report for the twelve months ended March 31, 2006. 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 forecasting approach for the future test year. My testimony sponsors Exhibit UP&L___(JTW-1) which sets out the data that supports my conclusions.

Q. Based on the results contained in Exhibit UP&L___(JTW-1), what level of price increase is necessary for PacifiCorp to earn a fair and equitable return on equity?

A. Dr. Hadaway recommends that the Company be given the opportunity to earn an 11.125% return on equity. To accomplish that return, the Company needs an increase of $123.6 million to general business revenues.

Q. Is PacifiCorp actually seeking to increase revenues by $123.6 million in this proceeding?

A. No. As explained in Mr. Taylor's testimony, the MSP Protocol stipulation caps PacifiCorp's FY 2006 Utah revenue requirement at 101.5 percent of the Utah revenue requirement calculated under the Rolled-in Allocation Method. The rate mitigation cap limits the Company's requested rate increase to $111.0 million, or $12.6 million less than the increase that is supported by Exhibit UP&L___(JTW-1).

Q. What is contained in Exhibit UP&L___(JTW-1)?

A. Exhibit UP&L___(JTW-1) is PacifiCorp's Utah Results of Operations Report ("Report"). The base year for the Report is Fiscal 2004, which has been normalized and used to forecast a twelve-month future test period ending March 31, 2006. The Report details revenues, expenses and rate base allocated to the Utah service territory based on the Revised Protocol methodology. A stipulation recommending that the Utah Commission adopt the Revised Protocol was filed on June 28, 2004. Mr. Taylor, in his direct testimony, describes the changes in jurisdictional allocation methodology between the previously adopted rolled-in method and the Revised Protocol. He also details the impacts of those changes on the Utah revenue requirement.

Q. Please describe the contents of the Report.

A. The Report provides twelve-month totals for FY 2006 forecasted revenues and expenses. Electric plant in-service and the accumulated depreciation reserve are based on a thirteen month average, with the remaining rate base calculated as the average of the beginning and end of FY 2006 forecasted balances. The Report presents operating results for the period in terms of both return on rate base and return on equity. Tab 1 of the Report provides summary information. Page 1.0 is a summary of the capped revised Protocol requested price change. Page 1.1 is a summary of the normalized Utah results of operations for the test period with a calculation of the increase in Utah retail revenues that would be necessary for the Company to earn 11.125% return on equity. The Total Adjusted Results (Column 1) is carried forward from the results of operations summary, Page 2.2, and shows a forecasted return on equity for Utah of 6.0 percent. The Price Change, (Column 2), shows that a price increase of $123.6 million in revenues is required to increase the return from 6.0 to 11.125% return on equity in Utah. Column 3 reflects Utah adjusted results with the $123.6 million price increase included. 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.

Tab 2 details the allocation of the forecasted results to Utah using the Revised Protocol Allocation Method (Protocol). Pages 2.3 through 2.38 contain Total Company and Utah allocated revenues, expenses and rate base detailed by FERC Account. Supporting documentation for the data in Tab 2 is provided under Tabs 3 through 10. The total column of the projected results on page 2.2 reflects the costs, revenues and rate base that have been calculated as described later in my testimony. The normalizing adjustments made to the 2004 base year data to reflect on-going costs of the Company are described in Tabs 3 through 8. Tab 9 is the same summary as provide in Tab 2 except the results are ran on the PITA Rolled-In methodology. Tab 10 contains the calculation of the Protocol allocation factors. The loads used for these factor calculations and for calculating the revenue and net power cost forecasts are explained further in testimony sponsored by Company witness Mr. Reed Davis.

Development of Projected 2006 Results of Operations

Q. Please explain the process used to forecast the results of operations for Fiscal 2006.

A. The Fiscal Year 2006 test year results used in this filing were projected using the historical base year ending March 31, 2004. From that base year, each of the revenue requirement components was first normalized to remove any non-recurring items. Retail revenues were forecasted by applying the current tariffs to fiscal year 2006 forecast loads. Other revenues such as wheeling and joint-use revenues were based on contracts, wholesale sales forecasts were developed using the Generation Resource Integration Dispatch (GRID) model described by Mr. Widmer and the revenue from the sale of SO_2 allowances was added to these totals. The development of the total revenue forecast is summarized under Tab 3.

The normalized base year operation and maintenance (O&M) expense was split between labor related and non-labor costs. The non-labor costs were escalated by utilizing functional specific Consumer Price Indices (CPI) prepared by Global Insight's Utility Cost of Service, release dated May 03, 2004. For those accounts where the O&M budget projection differed significantly from the escalated amounts due to high load growth and other test year-specific issues, the escalated amounts were adjusted to best reflect the expected test year conditions. The labor related costs were adjusted for expected wage increases, manpower levels and changes to employee benefit costs. Then the labor and non-labor costs were combined, and the resulting total O&M forecast is summarized in Tab 4-Operation and Maintenance Expenses. The net power cost forecast was produced using the GRID model and is summarized under Tab 5-Net Power Cost. Annual depreciation expense was developed by applying the Company's composite functional depreciation rates to the projected average plant balances as summarized in Tab 6-Depreciation and Amortization Expense. Tab 7 summarizes Income Taxes and Taxes Other Than Income, Tab 8 contains the Rate Base forecast, Tab 9 is the same summary as provide in Tab 2 except the results are ran on the PITA Rolled-In methodology. Tab 10 shows the Derivation of MSP Revised Protocol allocation factors. I will discuss the calculation of each of these components separately.

Q. The forecasting process that you have just described involves both the use of price indices and budget estimates. Why did the Company use this combined approach?

A. As Mr. Larson explains, the ability to use a future test year in this proceeding is critical if PacifiCorp is to have any reasonable chance of fully recovering the cost of serving its Utah customers in a timely manner. Therefore, the Company believes it must establish its ability to produce reliable future test years. Establishing the desired credibility requires the Company to demonstrate that its forecasting approach was reasonable, systematic and verifiable. With this goal in mind, PacifiCorp considered two possible approaches to developing the future test year forecast: the use of price indices and the use of budget projections. Ultimately, in light of the specific challenges being faced by PacifiCorp in serving its growing Utah load, it was determined that a combination of index-based forecasts and budget projections was the most reasonable approach.

Q. Why did PacifiCorp choose not to rely entirely on price indices to develop the future test year forecast?

A. The advantage of using price indices to produce a forecast is that the resulting calculations are easily understood and readily verifiable. However, a future year forecast based solely on applying price indices to a historic base period assumes that all future cost increases will track the general rate of inflation. This is certainly not the situation facing PacifiCorp. In order to serve rapidly growing Utah loads, and implement the recommendations of the Company's Storm Report, the Company will be making substantial capital additions to distribution plant and will be significantly increasing its distribution operation and maintenance (O&M) expense over historic levels in FY 2006 and beyond. The Company will also bring a new generating resource on line in the test year. Therefore, because of the expected dramatic growth in specific cost categories, a future test year based entirely on indexed prices changes would not best reflect the conditions expected in the rate-effective period.

Q. If price indices will not capture the extraordinary cost increases expected by PacifiCorp in the rate-effective period, why didn't the Company base its test year forecast entirely on FY 2006 budget projections?

A. PacifiCorp has full confidence in its budgeting procedures and the reasonableness of its budget forecasts. However, the reality of the situation is that budget estimates can become controversial when used for ratemaking. Forecasts based on price indices are perceived to be more straightforward calculations. At the risk of being repetitious, I will reiterate that it is the Company's goal in this proceeding to produce a future test year forecast that is reasonable and verifiable. Therefore, in the interest of simplicity the Company has escalated non-labor costs using price indices and then made further adjustments only for those items where FY 2006 budget forecasts showed significant differences from inflationary trends. These adjustments were made to increase or decrease cost requests accordingly. The areas where budget forecasts differ significantly from inflation-adjusted amounts are explained in greater detail by other witnesses. Darrell Gerrard addresses the reasons for rapidly growing distribution O&M and capital costs, and Dan Rosborough addresses increased pension and employee benefit costs.

Q. Please describe the efforts the Company has made to ensure that the forecasted future test year data is as accurate as possible?

A. The Company has realized from the very beginning that the overall accuracy of the forecast depends on the reliability of the budget projections in those key areas where costs are expected to increase dramatically during the rate-effective period. These key areas include distribution O&M and distribution capital additions, new generating resource capital additions, and pensions and employee benefits. Therefore, in my role as coordinator for the revenue requirement calculation in this case, I have had numerous face-to-face meetings with the individuals responsible for the preparing the key FY 2006 budgets forecasts. I reviewed their assumptions and calculations and determined them to be reasonable. These budget assumptions were also subjected to numerous "challenge meetings" throughout the Company's organization, culminating in a final review by PacifiCorp's senior management team.

Q. What is the dollar magnitude of the FY 2006 cost increases in the key areas you have identified?

A. As discussed in greater detail in Mr. Gerrard's testimony, the FY 2006 forecast shows an increase of $24.4 million in distribution O&M as compared to Exhibit UP&L___(JTW-2) and $283.5 million in distribution capital expenditures over FY2004 levels. As explained by Mr. Rosborough, the FY 2006 pension expense and employee benefit expense forecast is $17.7 million higher than FY 2005 levels. Finally, the FY 2006 forecast includes a $348 million capital addition for the Currant Creek generating plant that would not otherwise be reflected.

Q. What do you conclude about the overall reasonableness of PacifiCorp's future test year forecast in this proceeding?

A. Recognizing that ratemaking involves predictions about future conditions and that no prediction will ever be totally accurate, I believe that the future test year forecast that the Company has put forward in this case best reflects the conditions in the rate-effective period. It reflects adjustments for normal inflation based on nationally recognized cost indices, coupled with specific adjustments for rapidly escalating costs that have been carefully scrutinized and extensively reviewed.

Q. How does the Company's forecasted future test year revenue requirement for FY 2006 compare with the revenue requirement determined for a test period based on historical FY 2004 operating results with known and measurable adjustments through the end of FY 2005?

A. As I indicated earlier, the FY 2006 future test year proposed in this case shows the need for $123.6 million price increase in order for the Company to earn its requested ROE of 11.125%. Based on the Semi-Annual Results of Operations Report filed with the Commission on July 30, 2004 (included in this application as Exhibit UP&L___(JTW-2)), a historical FY 2004 test year with known and measurable adjustments through the end of FY 2005 would indicate the need for a $97.8 million price increase in order for the Company to earn an ROE of 11.125. This difference of $25.8 million is the amount of cost under-recovery that PacifiCorp would experience in the rate-effective period and beyond because a test year normalized through 2005 would fail to capture escalating costs.

Q. What do you conclude from the foregoing comparison?

A. I conclude that the use of a FY 2006 forecast future test year is the only means by which PacifiCorp can be provided a fair opportunity to completely recover the fair and reasonable cost of serving its Utah customers. This is the test period that best reflects the conditions that the Company will encounter during the rate effective period.

Revenues

Q. Would you describe the procedures used to forecast the Company's Fiscal Year 2006 revenues and explain the purpose of Tab 3, Revenue Adjustments?

A. The procedures used to forecast future test year revenues are summarized in Tab 3, which provides the detail of total Company revenues by FERC account starting with Fiscal Year 2004 revenue. The data in Tab 3 summarize forecasted test year revenues which were developed by applying current rates to the Fiscal Year 2006 load forecast and then further adjusting for revenues from other sources, such as wheeling, joint-use, wholesale sales and SO_2 allowances. Pages 3.1.1 through 3.1.4 summarize the normalization of base year (FY 2004) revenues and the projection of FY 2006 revenues. On these pages, the columns with the headings 3.2 - 3.8 summarize a normalization adjustment to the base period that is supported with a coversheet and work papers. Calculations made to roll the base year revenues forward to Fiscal 2006 are summarized in the columns headed 3.9 and 5.1. These pages are also supported by appropriate work papers. Account 456, Other Revenues, was held constant with the exception of wheeling revenues and the removal of one-time items that are described in the normalization adjustments. The far right-hand column titled "FY2006 Adjusted Revenues" contains the forecasted future test year revenues that are summarized in the revenue section of the results of operations in Tab 2. I will briefly describe each of the normalizing adjustments to base year revenue.

Weather Normalization (Adjustment 3.2) **–** Adjustment 3.2 normalizes revenues in the base year by comparing actual loads to temperature normalized loads.

Effective Price Change (Adjustment 3.3) **–** Adjustment 3.3 annualizes existing contracts and tariff changes to reflect a full year of revenues in the base year, based on approved rates.

Revenue Normalizing Adjustments (Adjustment 3.4) – Adjustment 3.4 normalizes the base year revenues by removing out-of-period adjustments.

Special Contract Reclassification (Adjustment 3.5) **–** Adjustment 3.5 normalizes base year revenues by reversing the system allocation of special contract revenues and assigns those revenues to their home state. The PITA Modified Accord agreement specified that any non-tariff based contracts entered into after January 1, 1997 would receive revenue credit treatment. The Protocol methodology developed by the Multi-State Process 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 being retained by their home state.

Rock River Warranty Reversal (Adjustment 3.6) – Adjustment 3.6 removes a non-recurring settlement from base year results.

One-Time Revenues (Adjustment 3.7) – Adjustment 3.7 adjusts base year revenues to remove one-time gains and losses.

Wholesale Trading Activity Removal (Adjustment 3.8) – The Company models the normalized wholesale sales and purchase activities in the net power cost calculations. Adjustment 3.8 removes net trading activities from the base year to avoid a double-count.

After the base year revenues have been normalized by Adjustments 3.2 – 3.8, a final adjustment (Adjustment 3.9) is made to add the difference between Fiscal Year 2004 base year general business revenues and the Fiscal Year 2006 test year revenue forecast.

Q. How was the Company's FY 2006 revenue forecast developed in the results of operations report?

A. The 2006 Utah Revenue Forecast for general business revenues is derived from forecasted kilowatt-hour sales priced at rates that the Commission authorized in Docket 03-2035-02. Mr. Reed Davis supports the load forecast in his testimony.

Mr. William Griffith explains the development of general business revenue from this forecast in his testimony, which will be filed with the rate spread and rate design portion of this case on August 27, 2004.

Q. How was Other Electric Revenue projected?

A. Other Electric Revenue is based on Fiscal Year 2004 amounts, adjusted to remove any non-recurring items. Wheeling revenues were forecasted based on existing contracts and capacity. Joint-Use revenues are also based on current rates and will need to be updated as this case proceeds.

Q. Why will joint use revenues need to be updated?

A. There are currently proceedings before the Commission that are looking at the appropriate attachment rate for customers attaching to PacifiCorp's pole network. At this time, these proceedings are not resolved and the potential resolution of these proceedings will likely result in a change to the revenues collected by PacifiCorp with respect to the joint use of these facilities. PacifiCorp therefore proposes to make an adjustment in this rate case proceeding to take account of either the increased or reduced forecasted revenues resulting from any revision to these existing arrangements.

Q. Other than the normalizing adjustments to base year revenues and the calculation necessary to forecast 2006 revenues have you made any additional revenue adjustments?

A. Yes. There is one additional adjustment (Adjustment 5.1) made to revenues to reflect the wholesale sales forecasted by the GRID model. Mr. Mark Widmer explains how these sales were forecasted in his testimony.

Q. Why doesn't this filing contain an adjustment to amortize S02 sales?

A. Over the years, PacifiCorp's annual revenues from the sale of emission allowances have fluctuated dramatically. Thus, the level of emission allowance sales in any particular year was not likely to reflect the ongoing level of revenue from future sales. Therefore, the Company's approach was to track these sales and amortize them over a four-year period.

However, since 2002, the Company has only sold the amount mandated by the EPA, which has been less than $600,000 a year. In the base year the sales were $585,037, which is consistent with the prior two years experience. Since the Company plans to continue with this level of sales in the future, we have held the base year actual emission allowance sales constant for the forecast.

Q. Why hasn't the Company included the WAPA wheeling revenue imputation adjustment previously ordered by this Commission?

A. The Company requests that the Commission reconsider this adjustment. It is the view of the Company that the WAPA contract, at current revenue levels, provides net benefits to PacifiCorp customers. Let me explain why.

The WAPA contract currently provides a revenue source greater than the cost of owning and operating a pro-rated share of the specific facilities used as they were contemplated in 1962. In 2003, total actual wheeling revenues were $2,819,275. The operating and maintenance cost attributable to the WAPA wheel was approximately $183,000 as it represents about 10 percent of the Utah control area load served by PacifiCorp. Total maintenance on the facilities used in the Utah control area was $1,825,690 in 2003. Therefore, out of the $2,819,275 of annual revenue from WAPA, approximately $2,636,000 was available as a contribution to fixed costs. Recognizing that the assets serving the WAPA wheel are more than 42 years old and largely depreciated, this contribution exceeds current fixed costs. In addition, WAPA is required to reimburse PacifiCorp for energy losses resulting from the WAPA Contract at a rate of 7 percent. PacifiCorp's current transmission loss factor is 4.48 percent

Q. Why do other firm wheeling contracts provide revenues based on PacifiCorp's average embedded revenue requirement?

A. I am advised that, under PacifiCorp's Open Access Transmission Tariff, PacifiCorp provides two types of firm wheeling service, Point-to-Point and Network. Both reflect rates designed to provide revenues based on an average embedded (or rolled in) revenue requirement. Under these agreements, a transmission customer is entitled to use the entire transmission system of PacifiCorp in exchange for paying a single system wheeling rate. For Point-to-Point Customers that rate is set by FERC tariff. Payment entitles the customer to the full firm rights on the contract transmission path. This would include the firm scheduling rights up to twenty minutes before each hour as well as the right to re-market its firm transmission reservation to other parties. Any revenues from such re-marketing would belong to the customer. In addition, a Point-to-Point customer can select alternative receipt and/or delivery points throughout PacifiCorp's entire transmission system with no additional charges from PacifiCorp. Network Customers pay for transmission services based on their contribution to PacifiCorp's average transmission system coincidental peak. They can use PacifiCorp's entire transmission system in serving their loads. Firm resources are deliverable on a firm basis, and alternate resources can be substituted up to twenty minutes before each hour with the highest level of priority for any non-firm use of the transmission system (i.e. PacifiCorp would have to curtail non-firm transmission service). In addition, PacifiCorp must plan and construct for these customers' load growth. The level of service that both Point-to-Point and Network transmission customers enjoy justifies a charge based on PacifiCorp's total transmission system cost of service.

Q. How does the service available to WAPA under the contract differ from the service provided to PacifiCorp's transmission customers paying for service based on average embedded transmission pricing?

A. WAPA is limited to the use of only those points of interconnection and points of delivery listed in the contract. WAPA may not substitute alternate resources or deliver its energy to alternate points of delivery. WAPA may not re-market any of its transmission rights to any party. Also, PacifiCorp has no planning or construction requirements resulting from load growth occurring within the load serving systems of WAPA's customers served from PacifiCorp under the WAPA contract. These circumstances need to be taken into account in determining whether PacifiCorp's charges to WAPA under the WAPA contract are just and reasonable.

Q. Does the WAPA contract provide any other benefits to PacifiCorp customers?

A. Yes. The lack of flexibility afforded to WAPA under the WAPA contract results in short term transmission marketing opportunities for PacifiCorp. PacifiCorp Transmission Systems actively markets available transmission scheduling rights over its Open Access Same-time Information System ("OASIS"). These available transmission rights can be from un-committed transmission capacity or from transmission capacity committed to others that remains un-scheduled (as is the WAPA contract transmission capacity throughout the year). These short-term transmission sales appear as revenue credits against the total system cost of service allocation to Utah retail customers, thus reducing rates. Based on calendar year 2003 the total amount of short-term transmission revenue credits allocated to Utah was $4,597,115. This is the product of total short-term revenues ($11,167,044) and Utah's allocation factor (41.1668%). In 2003, PacifiCorp's short term wheeling revenues associated with imports from Mona, Four Corners and Glen Canyon were $1,506,222, $837,812, and $237,725, respectively. This level of revenue would no doubt be adversely affected if WAPA controlled the flexibility in its scheduling practices or if it owned the right to re-market its transmission rights to others.

Operation and Maintenance (O&M) Expenses

Q. What is the purpose of the O&M Summary?

A. I have already detailed earlier in my testimony the process used to develop future O&M Costs for the future Test Period. Pages 4.1.1 through 4.1.12 provide a bridge between the O&M section of the results of operations in Tab 2 and the detail supporting the Company's 2006 O&M projections contained in Tab 4.

Q. How is Tab 4 organized?

A. The O&M summary begins with the Company's unadjusted Fiscal year 2004 O&M expense. Base year labor and employee benefits are then subtracted and additional normalizing adjustments are made to the remaining base year non-labor O&M expense. Each adjustment is listed in a separate column and the sum of 2004 actual non-labor O&M and the normalization adjustments are shown in the column titled "March 2004 Total Adjusted O&M (w/o labor)". These costs are then escalated to 2005 and 2006 levels using appropriate DRI indices for each FERC account. The non-labor O&M expense that has been escalated to the 2006 level is then added to the forecasted 2006 labor O&M expense and additional forecast changes beyond normal inflation are included to produce the total forecasted 2006 O&M expense. The supporting documentation for each of the base year adjustments is contained in Tabs 4.2 through 4.11 and the additional changes beyond normal inflation are described in Tabs 4.12 through 4.16.

Q. Please describe the adjustments made to base year (FY 2004) non-labor O&M expense in Tab 4.

A. The adjustments to base year non-labor O&M expense are summarized by column on pages 4.1.1 through 4.1.12, with the reference page and adjustment title pointing to the supporting documentation. I will briefly describe each of these adjustments:

Blue Sky Program (Adjustment 4.2) – 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.

Miscellaneous General Expense (Adjustment 4.3) – Adjustment 4.3 removes from the base year certain miscellaneous expenses that should have been charged below the line to non-regulated expense.

International Assignees (Adjustment 4.4) – Adjustment 4.4 removes from the base year expense the housing and other costs associated with international assignees who have either returned to Scotland or "localized" (transferred to the U.S. compensation package). Their labor-related costs for those international assignees who returned to Scotland are removed in the labor adjustment.

DSM Liability Write-Off (Adjustment 4.5) – PacifiCorp contracted for the development of some energy saving equipment for customers. PacifiCorp later sued for partial non-delivery and ultimately lost in arbitration, resulting in a liability being created in calendar year 2000. A settlement was later reached between the parties, and the Company wrote-off the liability. Adjustment 4.5 removes that liability write-off from the base year expense.

Customer Guarantee Reversal (Adjustment 4.6) – As part of the ScottishPower merger, a number of customer guarantees were made. A subsequent review discovered that some of the customer guarantee payments were incorrectly booked above the line. Adjustment 4.6 removes those payments from the base year expense.

New Generation (Adjustment 4.7) **–** The base year includes the write-off of some preliminary survey and investigation costs. Adjustment 4.7 removes these prior period costs from the base year expense.

Remove Settlement Termination Expenses (Adjustment 4.8) **–** During the base year the Company accrued a potential legal liability associated with the termination of the failed sale of the California service territory. Adjustment 4.8 removes these costs from the base year expense.

Workers' Compensation Expense (Adjustment 4.9) - The Company received notice that the Insurance Carrier used by the Company to provide employee Workers' Compensation insurance was in bankruptcy. Therefore, the Company 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. Because the reserve is not included in the results of operations, adjustment 4.9 removes the expense side of both the establishment of the reserve and the write-off transactions from base year expenses.

Amortization of Regulatory Asset (Adjustment 4.10) **–** Commission orders in Docket Nos. 99-035-10 and 01-035-01 established several regulatory assets with three to five year amortizations which will be fully amortized before the end of the future test period in this proceeding. Adjustment 4.10 removes those expiring amortizations and the associated remaining asset balances from the base period.

Customer Service Deposits (Adjustment 4.11) - As specified in Utah Electric Service Regulation No. 9, the Company pays interest on customer service deposits. These deposits are treated as a reduction to rate base and the interest is treated as an expense of electric operations. Absent this adjustment, the interest true up, Adjustment 7.1, would nullify any recovery of customer service deposit interest. This adjustment to base year expense was initially approved in Docket No. 97-035-01 and has been re-affirmed in each subsequent case.

In addition to the foregoing adjustments, there is also an adjustment to base year non-labor O&M expense related to the sale of the Skookumchuck Hydro Plant. This adjustment is discussed further in the Rate Base section of my testimony.

Q. Please describe how the Company forecasted FY 2006 labor costs.

A. Labor costs, including incentives, benefits, and costs associated with FAS 87 (Pension), FAS 106 (Post Retirement Benefits), and FAS 112 (Long Term Disability) were identified by FERC account and labor group. These labor-related expenses were then segregated from the other non-labor-related O&M costs so they could be escalated separately. Next, all base year wages for employees that had left the Company as of March 31, 2004 were removed. The remaining salaries were then annualized to get a full base year salary expense at the March 2004 wage level. The final step was to apply the wage increases for 2005 and 2006 to the annualized base year salaries to forecast the FY 2006 test period wages. Consistent with the approach the Company has used in previous Utah rate cases to prepare its general wage increase adjustment, union agreements were used to escalate union labor group wages and budgeted wage increases were used for non-union and exempt employees. Each union labor group was isolated and escalated in accordance with the individual union agreements. Next, projected changes in manpower were identified by business unit for Fiscal Years 2005 and 2006 and associated salaries were added to the escalated labor costs.

Employee benefits, including incentive compensation, medical, dental, vision, pension, post retirement, and long term disability were spread to FERC accounts on the same ratio as labor. Mr. Rosborough's testimony provides support for the projected increase in employee benefit expense. The labor forecast also reflects two accounting policy changes that were implemented in Fiscal Year 2004 pertaining to the treatment of payroll taxes and vehicle depreciation. Historically payroll taxes were recorded to FERC account 408 and vehicle depreciation to account 403. These expenses are now treated as a labor overhead and follow labor costs.

A detailed explanation of the process used to forecast test year labor is found in the Labor Tab under Tab 4.17.

Q. Please describe the further adjustments made to the O&M expenses after they were escalated to Fiscal Year 2006.

A. Seven additional adjustments were made to the escalated expenses to reflect forecasted increases in Fiscal Year 2006 operating expenses beyond normal inflation.

CBS System Support (Adjustment 4.12) – The Company continues to add additional software packages and systems. Adjustment 4.12 reflects the additional costs required to support these systems.

Property Insurance (Adjustment 4.13) – Adjustment 4.13 increases expenses in Account 924, Property Insurance, and Account 925, Injuries and Damages, to reflect the increase in premiums and uninsured losses for property and injury insurance the Company expects to experience during FY 2006.

Capital Lease Interest (Adjustment 4.14) – GAAP accounting requires a capital lease to be recorded on the balance sheet as a liability with an offsetting asset at its net present value. However, the balance sheet impact is any is not included in rate base. The monthly amortization of capital leases is comprised of two components, principle and interest which reflect the annual lease payment. The principle portion of the lease payment is recorded to account 930 and the interest component is recorded to account 431. For regulatory purposes PacifiCorp's interest expense is synchronized to net plant investment, because there is no asset on which to earn a return, this adjustment moves the interest component of the lease payment to account 930 to include the full capital lease expense in results.

Scottish Power Cross Charge (Adjustment 4.15) – PacifiCorp and Scottish Power UK (SPUK) executed a cross charge agreement governing the allocation of costs incurred by each entity on behalf of the other. Although SPUK has provided corporate services to PacifiCorp since the merger, cross charges only began to be invoiced as of April 2004. Six months earlier PacifiCorp filed details of the cross charge with the Commission in Docket No. 03-035-026. As a result of that filing the Division of Public Utilities recommended the Commission acknowledge the filing and resolve ratemaking treatment of Group Corporate costs in the Company's next general rate case.

Adjustment 4.15 reflects the SPUK annual cross charge to PacifiCorp of $13,044,000 per year, Utah's allocated share is $5,427,443. The cross charge is attributed to the following categories:

Corporate secretarial & shareholder services	$6.5 million
Group human resources	$1.5 million
Corporate finance	$3.0 million
Strategic planning	$0.5 million
IT services	$0.5 million
Corporate office space	$1.0 million
Total	$13 million

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 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 indicate 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 company that is asset light yet profitable will be allocated a larger share of corporate costs compared to the three-factor formula. About 46 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.

Current Creek (Adjustment 4.16) – The revised MSP protocol treats Currant Creek as a seasonal resource for the July 2005 through March 2006 timeframe when it operates as a simple-cycle combustion turbine generator. Adjustment 4.16 corrects the allocation by reclassifying the operation and maintenance costs for that timeframe from a System Net Plant Production factor to a seasonal generation factor in accordance with the Protocol allocation method.

Q. Do the adjustments in Tab 5, Net Power Costs, impact the O&M summary?

A. Yes, each of the Net Power Cost adjustments impact the O&M summary, and I will explain those adjustments in the Net Power Cost section of my testimony.

Net Power Costs

Q. How are the Company's forecasted net power costs for FY 2006 developed in the Results of Operations Report?

A. As described in Mr. Widmer's testimony, the net power cost 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 contractual terms. The net power costs are forecasted using the GRID model, as summarized in Net Power Cost Adjustment 5.1, and form the basis for the Company's future test year net power costs contained in Tab 2.

Depreciation and Amortization Expense

Q. How are the Company's forecasted depreciation and amortization expense for FY 2006 developed in the results of operation report?

A. A detail sheet supporting the calculation of the projected FY 2006 depreciation and amortization expense contained in Tab 2 is provided in Tab 6. The Company's approach to forecasting depreciation and amortization expense is explained in Tab 6, on page 6.0. In general, annual depreciation expense was developed by applying the Company's functional composite depreciation rates, based on the March 2002 depreciation study, to the 2005 and 2006 thirteen-month average plant balances, as shown on page 6.3. Page 6.1 summarizes FY 2004 actual depreciation expense and FY 2005 and FY 2006 forecasted depreciation expense.

Amortization expense for Fiscal Years 2004 through 2006 is summarized on page 6.2. Account 404, Intangible Plant Amortization, was forecasted for FY 2005 and FY 2006 by applying a composite amortization rate to the forecasted average intangible plant balances as shown on page 6.4. Amortization of plant acquisitions in Account 406 and un-recovered plant in Account 407 were held constant for straight-line amortization of these assets. The annual depreciation and amortization expense was added to the accumulated depreciation and amortization reserves on a monthly basis to project these balances forward to FY 2006. The procedures used to project FY 2005 and FY 2006 thirteen-month average rate base are explained in Tab 8.

Q. Would you explain how the composite depreciation rates were calculated and why the composite rates used aren't the same as those contained in the 2002 depreciation study?

A. Yes. The composite depreciation rates used in this filing are based on the current Commission authorized rates. These rates identified depreciable electric plant in service by function. Generation facilities were detailed by plant by FERC account; transmission investment was detailed by FERC account; and distribution and general plant were grouped by state by FERC Account. Remaining plant lives were determined and used to calculate the study depreciation rate. These rates were then applied to the depreciable plant balance to calculate the annual depreciation expense for each sub-category. The authorized composite rates were calculated by dividing the proposed depreciation expense summarized by function by the depreciable plant for that function. For this filing, the Company calculated composite rates by dividing the actual depreciation expense recorded during the base year by total March 2004 plant investment. This calculation is summarized on pages 6.11 through 6.12. The Company calculated composite rates based on total electric plant in service because the forecasts for plant additions were not detailed enough to allow the Company to identify depreciable versus non-depreciable plant.

Taxes

Q. Please describe the process of forecasting Fiscal Year 2006 taxes for use in the results of operations report.

A. Detail supporting the forecast of the future test period tax expense is provided in

Tab 7. An explanation of the Company's method for projecting the test year tax expense is provided on page 7.0 of that tab. For purposes of this discussion, tax expense is separated into the following categories: taxes-other-than-income, federal and state income taxes, Schedule M items, deferred taxes, and the Wyoming wind tax credit.

Taxes-Other-Than-Income - The forecast for taxes-other-than-income is shown on page 7.3. Property taxes are based on revenues, investment, and property valuations. The base year expenses were held constant with the exception of two items, payroll and property taxes. Payroll taxes for the base year were replaced by the FICA taxes calculated on the labor adjustment as shown on page 17 of the Labor Tab. Estimated property taxes for the 2006 test period were used.

State and Federal Income Taxes - Both state and federal income taxes were calculated by applying the applicable tax rates to the Utah allocated taxable income. The income taxes for book tax accrual and ratemaking are calculated using the same methodologies the Company uses in preparing its filed income tax returns. The detail supporting this calculation is contained on page 2.21.

Schedule M-1 Items - The Schedule M-1 items from the base year were reviewed and any non-recurring items were removed. The Schedule M impact of normalization adjustments and the timing differences of book versus tax depreciation associated with the capital additions were included. Pages 7.2.1 through 7.2.12 detail the Schedule M estimates for the FY 2006 test period.

Deferred Taxes - The combined federal and state deferred income tax expense includes the tax effect of the difference between operating income and income considered for income tax purposes. The non-property related Schedule M items were used to develop the estimated deferred income tax expense. The property-related deferred income tax expense was developed from the capital additions and retirements and the difference from tax to book depreciation. Tax depreciation and deferred tax expense and accumulated deferred income tax balances were calculated using those inputs. The deferred income tax summary is found on pages 7.1 with detail on pages 7.1.1 through 7.1.20.

Wyoming Wind Tax Credit - The final adjustment under the Tax Adjustment Tab is Adjustment 7.4, Wind Tax Credit. 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.

Rate Base

Q. Please describe how the Company developed the rate base projections used in the FY 2006 test period results of operations.

A. The detail for the projected average rate base for the FY 2006 test period is described in Tab 8. The key assumptions used in forecasting FY 2006 average rate base are summarized on page 8.0. Pages 8.1.1 through 8.1.18 summarize March 2004 base year balances, by FERC account, in the left-hand column and the net rate base changes by year for FY 2004, 2005 and 2006. The far right-hand column "FY2006 Projected Average Rate Base" is summarized on pages 2.22 through 2.38 of the Results of Operations. Pages 8.1.19 through 8.1.72

summarize the incremental change by year from FY 2004 to FY 2006 for each of normalization adjustment made to the base year. Detail for these adjustments is contained in Tabs 8.2 through 8.14.

Q. Please describe each of the adjustments to the base year (FY 2004) rate base balances.

A. **Environmental Settlement** (Adjustment 8.2) – 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 $33 million to cover the cost of Company clean-up sites. These funds were transferred to PacifiCorp Environmental Remediation Company (PERCO). 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) - PacifiCorp owns 21.4 percent interest in the Trapper Mine, which provides coal to the Craig Generating Plant. The normalized coal cost of Trapper Mine includes all operating and maintenance costs but does not include a return on investment. Adjustment 8.3 is necessary to add the Company's share of Trapper Mine plant investment to the base year rate base, since this investment is in 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) - PacifiCorp owns a 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. Therefore, this adjustment is necessary to properly reflect the Bridger Coal Company investment in base year rate base.

Miscellaneous Rate Base (Adjustments 8.5, 8.6 and 8.7) – These adjustments look at each of the regulatory assets to identify all those that will be fully amortized by March 2006 and remove those investments from rate base.

Customer Advances (Adjustment 8.8) – 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 the balance.

Sale of Naches (Adjustment 8.9) – The Naches hydroelectric facility has been sold. However, the transaction is not reflected in base year results. Adjustment 8.9 removes the sold assets from the base year rate base and adds back the accumulated depreciation.

Sale of Skookumchuck (Adjustment 8.10) - 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. The purpose for the sale is that current generating costs to produce power at the Skookumchuck hydroelectric unit is extremely high and is no longer efficient for PacifiCorp to continue to operate. Adjustment 8.10 removes all effects of the Skookumchuck dam, gross plant balance, accumulated depreciation and deferred tax balance, from the base year results of operations.

APS Combustion Turbine (Adjustment 8.13) - In December 1996, the Company recorded a $23 million payment to Arizona Public Service Company (APS) pursuant to a Combustion Turbine Construction agreement that was part of the August 1991 contract to purchase the Cholla 4 generating station. This payment was recorded as a deferred debit in account 182.399 and is being amortized over the 26 year life of the plant beginning August 1991. The Utah Commission in its order dated March 4, 1999 in Docket No. 97-035-01 ordered a sharing of the $23 million payment between customers and shareholders. This sharing is achieved by leaving the annual amortization expense in results and removing the unamortized balance from rate base. This adjustment removes from base year rate base the unamortized average balance of the deferred debit being amortized over the 26 year life of the plant as approved by the Utah Commission. The amortization continues through July 2017.

Deferred Tax Update (Adjustment 8.14) – The tax balances for the base period were normalized to remove items collected on separate riders and non-regulated balances. The non-property Schedule M-1's for the test period were used to develop the forecasted deferred expense and corresponding balance. The property related deferred income tax balance was developed from the capital additions in pages 8.12 through 8.13 and resulting book and tax depreciation differences.

Q. Does this describe all of the adjustments to the base year (FY 2004) rate base?

A. Yes. There was one additional adjustment to rate base that was approved by the Commission that is no longer necessary to make. The Commission had approved a sharing adjustment for Organizational costs associated with the Utah Power-Pacific Power merger that were recorded in 1990. These costs were amortized over fifteen-years and are fully amortized prior to the test period, making this adjustment no longer necessary.

Q. Would you describe how the base year balances were walked forward to FY 2005 and FY 2006 to create the thirteen-month average plant balances summarized in the Report?

A. The forecasted plant additions with completion dates as of March 31, 2005 and March 31, 2006 are summarized in Adjustments 8.11 and 8.12, respectively. These capital additions were identified in a four-step process. First, the estimated completion dates for existing construction work in progress was determined, then the planned capital projects were identified. The next step was to separate the projects with completion dates during Fiscal 2005 into one group and those with completion dates in 2006 into another. The final step was to summarize these projects by plant function. These balances were then summarized and netted against the estimated retirements. The retirements were estimated by calculating a five-year average percent of retirements to plant investment by functional group. These percentages were then applied to the year-end balances to estimate retirements for each year, which were subtracted from rate base.

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

A. Yes.

Q. Would you describe the rest of the Report?

A. 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 Protocol allocation methodology. These factors are based on the loads provided by Mr. Davis and the plant balances contained in this Report. Mr. Taylor describes the derivation of those allocation factors in his testimony.

Q. Does this conclude your testimony?

A. Yes.