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

A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah, Suite 2000, Portland, Oregon, 97232. I am currently employed as Manager of Revenue Requirement.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a Bachelor of Science degree in Business Management, with an emphasis in finance from Brigham Young University in 2003. In addition to my formal education, I have also attended various educational, professional and electric industry-related seminars. I have been employed by PacifiCorp since 2002 in various positions within the regulation and finance organizations. I assumed my current position in 2008.

Q. Please describe your present duties.

A. My primary responsibilities include the calculation and reporting of the Company's revenue requirement, assuring that the applicable inter-jurisdictional cost allocation methodologies are correctly applied, and providing the explanation of those calculations to regulators in the jurisdictions in which the Company operates.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My direct testimony addresses the calculation and need for the $34.9 million increase requested in the Company's application. In support of this calculation, I address the following issues:

- A summary of the calculation of the $34.9 million requested rate increase.
- A description of the test period used in this case, which is the twelve months ending June 30, 2007 with known and measurable adjustments through June 30, 2008.
- The Washington revenue requirement calculation and revenue increase, including:
  - June 2007 actual results of operations;
  - Adjustments to the June 2007 results of operations;
  - The West Control Area allocation method, which is used to develop the Washington revenue requirement for this general rate case; and
  - The treatment of applicable commitments made as a condition for approval of MidAmerican Energy Holdings Company's (MEHC) acquisition of PacifiCorp (Docket UE-051090).

Required Rate Increase

Q. What price increase is required to achieve the requested return on equity in this case?

A. Presented as an exhibit to my testimony is the Company's Washington Results of Operations for the twelve months ending June 30, 2007, adjusted for known and measurable changes through June 30, 2008, labeled as Exhibit No.___(RBD-2). Based on the results of operations for this test period, at current rate levels PacifiCorp will earn an overall Return on Equity (ROE) in Washington of 3.8 percent. This return is less than the 10.2 percent ROE authorized in the order in

Docket UE-061546 and is less than the 10.75 percent return recommended in this proceeding in Dr. Hadaway's testimony to provide a fair and equitable return for the Company's shareholders. An overall price increase of $34.9 million is required to produce the 10.75 percent ROE requested by the Company in this proceeding.

Q. What allocation methodology was used in the calculation of the Washington Results of Operations?

A. The Company has used the West Control Area allocation method, as approved by the Washington Utilities and Transportation Commission (Commission) in Docket UE-061546 to calculate Washington's Results of Operations and the associated ROE. As discussed at length in the Company's last rate case filing, this allocation methodology includes all generation and transmission resources that lie within or have delivery capability to the west control area. The use of this methodology resulted in a Washington ROE of 3.8 percent for the twelve months ending June 2007 adjusted for known and measurable changes, and a required rate increase of $34.9 million to earn a 10.75 percent ROE.

Q. Please describe some of the key areas where the Company has experienced cost increases that support the $34.9 million requested price increase.

A. Since the 2006 Washington general rate case, the Company has incurred cost increases to serve its customers in two main areas: new plant investment and net power costs.

- The Company continues to make significant investment to serve its customers. Washington allocated net rate base has increased by over $98 million from the amount included in the Company's last Washington rate case filing. Significant new generating plant investments which were either not included or not fully included in the prior rate case include the Leaning Juniper Wind plant, Marengo Wind plant and the Goodnoe Hills Wind plant as described in the direct testimony of Mr. Tallman.

- The Company is continuing to see significant increases in Transmission and Distribution plant in service. This case includes more than $46 million in transmission plant additions for the west control area and $16 million in Washington distribution plant additions between July 1, 2007 and June 30, 2008.
- Net power costs, as addressed in the direct testimony of Dr. Shu, are projected to increase $41 million on a west control area basis or approximately $9 million on a Washington allocated basis as compared to the amount included in the Company's last Washington rate case.

Overview of the Test Period

Q. Please provide an overview of the test period in this case.

A. The Company has proposed a test year in this case that is based on the historical twelve month period ending June 30, 2007, adjusted for known and measurable changes through June 30, 2008.

Q. Please describe the process used to develop test period costs and revenues.

A. Operation and Maintenance (O&M) expenses were developed using historical expense levels for the twelve months ending June 30, 2007, adjusted for known and measurable changes through June 30, 2008. All components of Labor –

wages, pensions, and benefits – were adjusted on a pro forma basis for the twelve months ending June 30, 2008. This is consistent with the Company's previous general rate case, in which Commission Staff advocated and the Commission adopted an adjustment to include pro forma wages.

Plant and associated accumulated deprecation balances were developed using historical balances adjusted for pro forma capital additions through June 30, 2008. The matching of plant balances with accumulated depreciation balances has been previously advocated by Public Counsel and adopted by the Commission in Docket UE-050684

Net power costs for the west control area were developed using the Generation and Regulation Initiatives Decision tools model (GRID), based on terms of existing contracts, plant availabilities that are normalized using historical information, and pro forma retail load and market prices for the twelve months ending June 30, 2008. This forward looking approach was proposed by Commission Staff in the Company's previous rate case. The Company accepted this change in its rebuttal case and this methodology was adopted by the Commission in its final order.

Consistent with this approach, retail revenues were developed by applying the current Commission-approved tariff rates to the pro forma loads used in the net power cost study. In addition, these same pro forma loads are the basis for the calculation of West Control Area allocation factors. This methodology aligns retail revenues, net power costs and allocation factors. Each of these components will be discussed in more detail later in my testimony.

Revenue Requirement Calculation

Q. Please describe Exhibit No.___(RBD-2).

A. Exhibit No.___(RBD-2), is PacifiCorp's Washington Results of Operations Report. This report provides totals for revenues, expenses, depreciation, taxes and rate base, from both a total-company perspective and as allocated to the Company's Washington jurisdiction. Net power costs are presented for the west control area and as allocated to the Company's Washington jurisdiction. This report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit No.___(RBD-2) is organized.

A. Tab 1 Summary is the Washington allocated results based on the West Control Area allocation methodology.

Column (1) Total Adjusted Results on Page 1.1 is the Washington results of operations for the test period and shows the normalized Washington earnings. The Total Adjusted Results column is carried forward from the results of operations summary, Page 2.2, and shows Washington's ROE at 3.8 percent. Column (2) Price Change indicates that a revenue increase of $34.9 million is required to raise the ROE from 3.8 percent to 10.75 percent in Washington. Column (3) Results with Price Change reflects the Washington's adjusted revenue requirement with the $34.9 million price increase included. Page 1.2 of Tab 1 supports the calculation of additional revenue-related uncollectible expense associated with the price change requested in column 2 and the net-to-gross bump-up percent. Page 1.3 details the calculation of the net operating income percentage.

Tab 2 details total company and Washington allocated normalized results based on the West Control Area allocation methodology. Pages 2.3 through 2.41 contain revenues, expenses and rate base detail by Federal Energy Regulatory Commission (FERC) account. The Total Column of the 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 actual period data to reflect on-going costs of the Company are described in Tabs 3 through 8. Tab 10 contains the calculation of the West Control Area allocation factors.

Tabs B1 through B21 contain the historical results for the twelve month period ending June 30, 2007 and are organized by major FERC function.

Tab 3 – Revenue Adjustments

Q. Please describe the procedures used to develop the Company's test period revenues and explain the entries behind Tab 3, Revenue Adjustments.

A. The pro forma revenue and adjustments are contained in Tab 3, which begins with an overview and brief summary of the assumptions used to develop test period revenues. This is followed by a numerical summary (pages 3.0.2 – 3.0.4) by FERC account and allocation factor starting with actual revenue and summarizing each adjustment to get from the actual data to the normalized level included in the test period.

Pro Forma Revenue (page 3.1) – This adjustment reflects the incremental changes to walk from historical revenues to the test period pro forma revenues shown on page 3.1.1.

Revenue Correcting Adjustment (page 3.2) – In reviewing the historic data for the twelve months ending June 30, 2007, the Company discovered two adjustments that needed to be made:

- The general business revenues in unadjusted results during the twelve months ending June 30, 2007 are allocated by profit centers. The Company has profit centers in California, Oregon and Washington that cross state boundaries. This adjustment correctly assigns allocation factors based on the location of the revenues rather than profit centers for the affected jurisdictions.
- A review of FERC account 456, other electric revenues, was completed to verify that all of the revenues were correctly recorded in the unadjusted data. This adjustment corrects the allocation factor on several transactions where other electric revenues were assigned incorrect allocation factors in unadjusted results.

SO2 Emission Allowances (page 3.3) – Over the years, the Company's annual revenues from the sale of emission allowances have been uneven. Consistent with the Commission's order in Docket UE-940947, the Company has amortized all sales of emission allowances over a 15-year period. In addition, this adjustment includes pro forma sales through June 30, 2008. Washington's allocation of these sales is based on allowances provided by the Jim Bridger and Colstrip generating facilities, which are included as part of the west control area.

Wheeling Revenues (page 3.4) – During the twelve months ending June 30, 2007 various wheeling transactions took place which the Company does not expect to continue. These relate to prior period adjustments and contract terminations. This adjustment normalizes wheeling revenues to the anticipated level for the twelve month period ending June 30, 2008. In addition, the adjustment includes pro forma wheeling revenues for the twelve months ending June 30, 2008, including an adjustment for additional revenues associated with the Malin – Indian Springs transmission line.

Green Tag Revenues (page 3.5) – A market for green tags or Renewable Energy Credits is developing where the tag or "green" traits of qualifying power production facilities can be detached and sold separately from the power itself. This adjustment reflects the revenues associated with green tag sales for the twelve months ending June 2008 based on megawatt hours (MWh) included in the GRID study.

Q. Are there additional adjustments to revenue that are included in other portions of the Exhibit?

A. Yes. The following adjustments from other portions of my exhibit impact the revenues included in the revenue requirement calculation:

Accounting Correction (page 4.9)
K2 Risk Management System Removal (page 4.11)
Net Power Cost Adjustment (page 5.1)
James River Royalty (page 5.4)
Customer Service Deposits (page 8.9)

These adjustments are described under the Tab in which they are located.

Tab 4 – Operation & Maintenance Expenses

Q. Please describe the procedures used to develop the Company's test period operations and maintenance expenses and explain the entries behind Tab 4, O&M Adjustments.

A. O&M expenses included in the test period are based on the historical expense levels for the twelve months ending June 30, 2007, adjusted for known and measurable changes through June 30, 2008. The O&M Summary begins on page 4.0.1 with a page containing assumptions used in the development of the test period O&M expenses. The assumption page is followed by a step-by-step numerical summary of how the historical costs are adjusted to the expense levels included in the test period.

Q. Please describe the O&M numerical summary.

The numerical summary is found on page 4.0.2 through page 4.0.15. The detail in this tab supports pages 2.6 through 2.16. Each adjustment is listed in a separate column. These columns are totaled to produce the test period normalized O&M shown in the column on the right-hand side of the page, titled June 2008 Normalized O&M.

The numerical summary is organized by FERC account and allocation factor starting with the unadjusted data for the twelve-month period ending June 30, 2007. Each column has a numerical reference to a corresponding page in Exhibit No.___(RBD-2), which contains a lead sheet. Each lead sheet shows the FERC account affected by the adjustment, allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to the historical O&M expenses in Tab 4.

A. **Miscellaneous General Expense (page 4.1) –** This adjustment removes from results of operations certain miscellaneous expenses that should have been charged below the line to non-regulated accounts.

Wage & Employee Benefit Adjustment (pages 4.2 and 4.3) – This adjustment is described later in my testimony.

MEHC Transition Savings (page 4.4) – After completion of the MEHC acquisition of the Company, certain cost saving programs were implemented. In Docket UE-061546, the Commission authorized recovery of the severance costs associated with the acquisition through a regulatory asset to be amortized over three years. In accordance with that order, this adjustment removes the salary and severance paid to these former employees, reduces the regulatory asset to reflect the average balance in the test period, and includes twelve months of amortization expense.

Irrigation Load Control Program (page 4.5) – Incentive payments made to Idaho customers participating in the Schedule 72 irrigation load control program were initially booked as system allocated costs in unadjusted results. This adjustment corrects that allocation assigning these costs situs to Idaho, consistent with the situs assignment of other Demand Side Management (DSM) programs.

Incremental Generation O&M (page 4.6) – This adjustment annualizes the O&M expense associated with the Leaning Juniper Wind plant which was placed in service September 14, 2006. This adjustment also adds incremental operation and maintenance expenses for generating units that were not in service during the twelve months ending June 30, 2007 but will be in service during the twelve months ending June 30, 2008. The net power cost benefits associated with these additional resources are included in the net power costs in Tab 5.

Postage Increase (page 4.7) – Effective May 14, 2007, the U.S Postal Service increased its rates by $0.02 from $0.29 to $0.31 for utility mailings. This adjustment reflects that additional cost by applying the two-cent increase to the average number of retail customers during the historical period June 30, 2007. This adjustment also includes an increased number of customers based on the Company's load projections through June 30, 2008.

Grid West Loan (page 4.8) – This adjustment includes the rate base, associated amortization expense, and tax entries related to the Grid West Loan consistent with the Commission order in Docket UE-061546.

Accounting Correction (page 4.9) – In late 2006 it was discovered that in some instances offsetting entries in the labor pool were being charged to inconsistent accounts and/or locations. An entry in December 2006 corrected this for calendar year 2006. This entry removes the portion of the correction that relates to January through June 2006 which is out of period for this filing. An entry in September 2007 made similar corrections for January through June 2007, which should be reflected in the test period. This adjustment is done in four parts on pages 4.9 through 4.9.3, which are summarized on page 4.9.3.

Blue Sky (page 4.10) – This adjustment removes costs associated with the Blue Sky program. The Blue Sky program is designed to encourage voluntary participation in the acquisition and development of renewable resources. To prevent non-participants from subsidizing the program, this adjustment removes administrative and other expenses directly associated with the program.

K2 Risk Management System (page 4.11) – This adjustment removes the K2 Risk Management system from results of operations. This project was capitalized during calendar year 2006. However, the project was written-off/retired during March 2007 as the project had been deemed not used and useful. This adjustment removes the expenses of the project which are included in FERC accounts 921 and 922, and also removes the loss on the disposition of the asset in FERC account 421 included in the revenue summary in tab 3.

MEHC Affiliate Management Fee Commitment (page 4.12) – This adjustment complies with MEHC acquisition commitments and has two elements. First, MEHC commitment Wa 4 states:

> a) MEHC and PacifiCorp will hold customers harmless for increases in costs retained by PacifiCorp that were previously assigned to affiliates relating to management fees. The total company amount assigned to PacifiCorp's affiliates is $1.5 million per year, which is the amount of the total company rate credit. This commitment expires on December 31, 2010. This Commitment is in lieu of Commitment 38, and a state must choose between this Commitment Wa 4 and Commitment 38. (The commitment is reflected in Row 2 of Appendix 2.)
>
> b) This commitment is offsetable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case the following:
>
> > i) Corporate allocations from MEHC to PacifiCorp included in PacifiCorp's rates are less than $7.3 million;
> >
> > ii) Costs associated with functions previously carried out by parents to PacifiCorp and previously included in rates have not been shifted to PacifiCorp or otherwise included in PacifiCorp's rates; and
> >
> > iii) Costs have not been shifted to operational and maintenance accounts (FERC accounts 500-598), customer accounts (FERC

> accounts 901-905), customer service and informational accounts (FERC accounts 907-910), sales accounts (FERC accounts 911-916), capital accounts, deferred debit accounts, deferred credit accounts, or other regulatory accounts.

This adjustment reduces corporate allocations from MEHC included in rates to the $7.3 million level identified in item i) above, which offsets the need for any additional adjustment related to this commitment.

MEHC commitment WA 6 states:

> a) MEHC and PacifiCorp will hold customers harmless for increases in costs resulting from PacifiCorp corporate costs previously billed to PPM and other former affiliates of PacifiCorp. Oregon Commission Staff has valued the potential increase in total company revenue requirement if these costs are not eliminated as $7.9 million annually (total company) through December 31, 2010 and $6.4 million annually (total company) from January 1, 2011 through December 31, 2015, which shall be the amounts of the total company rate credit. This commitment shall expire on the earlier of December 31, 2015 or when PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case, that corporate costs previously billed to PPM and other former affiliates have not been included in PacifiCorp's rates. This Commitment is in lieu of Commitment 38, and a state must choose between this Commitment Wa 6 and Commitment 38.
>
> b) This commitment is offsetable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case, that corporate costs previously billed to PPM and other former affiliates have not been included in PacifiCorp's rates.

PacifiCorp has reduced costs and transferred 31 employees to PPM Energy (PPM) who had been previously charging part of their time to PPM. This will result in annual salary and benefit savings in excess of $6.2 million on a total company basis.

DSM Expenditure Removal (page 4.13) – Washington allows for recovery of DSM expenses through the system benefit charge (SBC) tariff rider. This adjustment removes Washington DSM costs in order to prevent a double recovery through base revenue requirement and the SBC tariff rider.

Non-Recurring Expense Adjustment (page 4.14) – Accounting adjustments were made to expenses that were non-recurring in nature or related to prior periods. This adjustment removes these non-recurring items from the historical twelve month period ending June 30, 2007, reducing total company operating expense by $9.7 million. Details on the specific adjustments can be found on page 4.14.1 of Exhibit No.___(RBD-2).

Captive Insurance Adjustment (page 4.15) – This adjustment demonstrates the Company's compliance with MEHC acquisition commitment Wa 5 which states:

> a) MEHC commits to use an existing, or form a new, captive insurance company to provide insurance coverage for PacifiCorp's operations. The costs of forming such captive will not be reflected in PacifiCorp's regulated accounts, nor allocated directly or indirectly to PacifiCorp. Such captive shall be comparable in costs and services to that previously provided through ScottishPower's captive insurance company Dornoch. MEHC further commits that insurance costs incurred by PacifiCorp from the captive insurance company for equivalent coverage for calendar years 2006 through 2010, inclusive, will be no more than $7.4 million (total company). Oregon Commission Staff has valued the potential increase in PacifiCorp's total company revenue requirement from the loss of ScottishPower's captive insurance affiliate as $4.3 million annually, which shall be the amount of the total company rate credit. This commitment expires on December 31, 2010.
>
> b) This commitment is offsetable if PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case, the costs included in PacifiCorp's rates for such insurance coverage is not more than $7.4 million (total company). (This commitment is reflected in Row 3 in Appendix 2.)

Actual captive insurance expenses for the historical twelve month period ending June 30, 2007 were less than the $7.4 million level identified in this commitment. As a result, no additional adjustment to expense is required.

A&G Cost Commitment Adjustment (4.16) – This adjustment demonstrates the

Company's compliance with MEHC acquisition commitment Wa 7 which states:

> a) MEHC and PacifiCorp commit that PacifiCorp's total company A&G costs will be reduced by $6 million annually based on the A&G categories, assumptions, and values contained in Appendix 3 titled, "UM 1209 A & G Stretch." The maximum amount of the total company rate credit in any year is $6 million. This commitment expires December 31, 2010. Beginning with the first month after the close of the transaction, Washington's share of the $0.5 million monthly rate credit will be deferred for the benefit of customers (unless included in rates in Docket No. UE-050684, PacifiCorp's current general rate proceeding), and accrue interest at PacifiCorp's authorized rate of return. This Commitment is in lieu of Commitment 22 and Commitment U 23 from the Utah settlement, and a state must choose between this Commitment Wa 7 and Commitments 22 and U 23.
>
> b) The credit will be offsetable, on a prospective basis, for every dollar that PacifiCorp demonstrates, to the Commission's satisfaction, in a subsequent general rate case, that total company A&G expenses included in PacifiCorp's rates are less than $6 million above the "Stretch Goal" and have not been shifted to other regulatory accounts. The 2006 Stretch Goal is $222.8 million. Subsequent Stretch Goals shall equal the 2006 Stretch Goal multiplied by the ratio of the Global Insight's Utility Cost Information Service (UCIS)-Administrative and General – Total Operations and Maintenance Index (INDEX CODE Series JEADGOM), for the test period divided by the 2006 index value. If another index is adopted in a future PacifiCorp case, that index will replace the aforementioned index and will be used on a prospective basis only. If this occurs, the Stretch Goal for future years will equal the Stretch Goal from the most recent full calendar year multiplied by the ratio of the new index for the test period divided by the new index value for that same most recent calendar year.

Normalized total company administrative and general expenses for the test period in this proceeding are less than $6 million above the Stretch Goal identified in this commitment requiring no additional adjustment to the total A&G expense level included in this filing.

Q. Please describe how the Company adjusted wage and benefit expenses for the test period.

A. Wages and benefits are adjusted on Pages 4.2 and 4.3. The Company projects labor and labor-related costs by adjusting salaries, incentives, benefits, and costs associated with FAS 87 (Pension), FAS 106 (Post Retirement Benefits), and FAS 112 (Long Term Disability). Page 4.3.2 is a numerical summary starting with historical labor expenses for the twelve-month period ending June 30, 2007 followed by the adjustments necessary to reflect expense levels for the twelve months ending June 30, 2008. This summary is followed by the detailed worksheets used to adjust the labor costs.

The first step was to annualize salary increases that occurred during the historical twelve-month period ending June 30, 2007. This was done by identifying actual wages by labor group by month and when each labor group received wage increases. Those increases were then applied to wages paid prior to the effective date to annualize salary expense. The next step was to repeat that process by applying the wage increases for July 1, 2007 through June 30, 2008 to the annualized historical salaries to project test period wages. The Company used union contract agreements to escalate union labor group wages, while increases for non-union and exempt employees were based on budgeted increases. This calculation is detailed on pages 4.3.3 through 4.3.5.

Q. Was an adjustment made to the annual incentive plan payout?

A. Yes. The incentive plan is described in the testimony of Company witness Mr. Wilson. The net impact of this adjustment was a reduction in total company incentive compensation of $4.1 million from the historical expense level as shown on page 4.3.2.

Q. Were employee pension and benefit costs adjusted in this section also?

A. Yes. Consistent with all other labor related costs, pension and other employee benefit costs were itemized starting with the historical expense levels for the twelve months ending June 30, 2007 and walked forward to June 30, 2008. Total pension costs decrease by $15.8 million between the historical period of June 2007 and the amounts included in the test period. These projections were provided by Mr. Wilson and supported in his testimony.

Q. Does the Wage and Benefit Adjustment cover any other items?

A. Yes. Payroll taxes were updated to capture the impact of the changes to employee salaries. This was calculated by applying the FICA tax rates to the net change in salaries and also to reflect the change in the social security cap for the twelve month period ending June 30, 2008.

Q. How are the Wage and Benefit adjustments incorporated into the O&M Summary?

A. The annualizing and pro forma labor adjustments are included in the O&M numerical summary by FERC account and allocation factor based on the same percentage that existed in the historical period.

Q. Does the Wage and Benefit adjustment include any adjustment for changes in workforce levels?

A. No. The wage and employee benefit adjustment assumes a constant level of workforce. The labor savings from the reduction in the number of employees due to the MEHC transaction was reflected in the MEHC Transition Savings adjustment discussed earlier in my testimony.

Tab 5 – Net Power Cost Adjustments

Q. How was the Net Power Cost adjustment calculated?

A. The Net Power Cost adjustment normalizes revenues and expenses in a manner consistent with normalized operation of production facilities. Page 5.1 is an overview of the $451.1 million in west control area net power costs included in the filing. The normalized west control area Net Power Costs are discussed in Dr. Shu's testimony.

Q. Please describe the Net Power Cost adjustments included in Tab 5.

A. **Net Power Cost Adjustment (page 5.1) –** Page 5.1 is an overview of the west control area power costs included in this filing. Pages 5.1.1 through 5.1.10 are the support sheets from the GRID report.

The Net Power Cost adjustment normalizes steam and hydro power generation, fuel, purchased power, wheeling expense, and sales for resale in a manner consistent with the contractual terms of the Company's sales and purchase agreements. It also normalizes hydro, weather conditions and plant availability as described in Dr. Shu's testimony. The revenue amounts from this adjustment flow to pages 3.0.2 through 3.0.4, and the expense amounts flow to 4.0.2 through 4.0.15.

Removal of Colstrip Unit #3 (page 5.2) – As directed by the Commission in Cause U-86-02, this adjustment removes the costs (except fuel expense which was removed from normalized net power costs) of the Colstrip Unit #3 plant from the results.

BPA Exchange (page 5.3) – The Company received a monthly BPA purchase power credit from BPA. This credit was treated as a 100 percent pass-through to eligible customers. Both a revenue credit and a purchase power expense credit are posted to unadjusted results. The revenues are reversed as part of the revenue normalization adjustment. This adjustment reverses the BPA purchase power expense credit recorded during the historical period, twelve months ending June 30, 2007.

James River Royalty Offset (page 5.4) – On January 13, 1993, the Company executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, the Company built a steam turbine and is recovering the capital investment over the twenty-year operational term of the agreement as a royalty offset. The agreement also includes payment of royalties from the Company to James River based on contract provisions. Included in PacifiCorp's net power costs as purchased power expense are the contract costs of energy for the Camas unit, but GRID does not include an offsetting revenue credit for the capital cost recovery and maintenance cost recovery amounts. Adjustment 5.4 adds this royalty offset to FERC account 456, Other Electric Revenue, for the twelve month period ending June 30, 2008.

Tab 6 – Depreciation and Amortization Expense Adjustments

Q. How are the Company's depreciation and amortization expenses developed in this filing?

A. Detailed worksheets supporting the calculation of depreciation and amortization expense contained in Tab 2 are provided in Tab 6. The depreciation and amortization expense amounts included in this filing are summarized on pages

6.1.1 and 6.1.2. Depreciation and amortization expense is calculated by applying functional composite depreciation and amortization rates to pro forma plant balances. Pro forma plant balances are developed as described in Tab 8. A description detailing the depreciation and amortization expense calculation can be found on page 6.0.

The methodology of applying composite rates to pro forma plant balances results in a test period depreciation expense of $439.1 million and amortization expense of $55.6 million. The calculation of these amounts is detailed on pages 6.1.3 to 6.1.10. The $439.1 million of depreciation expense reflects the depreciation rates currently approved by the Commission in Docket UE-021271.

Included in depreciation and amortization expense are items in addition to the amount calculated as described above. Adjustment 4.8 Grid West Loan, adjustment 8.6 Powerdale Decommissioning, and adjustment 8.8 Trojan Removal each contains amortization expense adjustments. Amortization of the plant acquisition adjustment in FERC account 406 is held constant at the historical period amount.

Q. How are the accumulated depreciation and amortization balances included in the filing calculated?

A. Accumulated depreciation and amortization balances are calculated by applying depreciation and amortization expense and plant retirements to the historical June 2007 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2007 to June 30, 2008. The monthly balances from June 2007 through June 2008 are used to calculate the average of the monthly averages reserve balance included in this filing. This averaging methodology is used to align the treatment of the reserve balances with the treatment of the electric plant in service (EPIS) balances explained on page 8.0. The reserve balance calculations are detailed on pages 6.2.1 to 6.2.8.

Q. Will this adjustment be updated when new rates are approved by the Commission?

A. Yes. The depreciation and amortization expense and balances will be updated for the depreciation rates approved by the Commission in Docket UE-071795. Since this case is based on the historical twelve month period ending June 2007 adjusted for known and measurable changes through June 30, 2008, the Company will update this filing by applying the new rates to plant balances from January 1, 2008 through June 30, 2008.

Tab 7 – Tax Adjustments

Q. Please describe the process of developing taxes for use in the results of operations report.

A. An explanation of the Company’s method for projecting the test period tax expense is provided on page 7.0 of that tab. Tax expense is separated into three main categories: Schedule M items, Deferred Income Tax Expense and Balances, and Taxes other than Income. The other sections in this tab contribute to one of these main categories. Detail supporting the development of the test period tax expense is provided in Tab 7.

Schedule M Items (page 7.1) – The Schedule M items at June 30, 2007 were used to develop the June 2008 amounts. Non-utility items, items that are recovered under separate tariffs, and other non-recurring items were removed from the June 2007 base period. For example, Schedule M items related to the Grid West Note Receivable and Trojan were removed. Normalizing adjustments were then added, such as adjustments to Pension & Benefits and SO2 Emission Allowances. The Schedule Ms were also adjusted for the Production Activity Deduction. Depreciation differences on capital additions were generated in order to bring the Schedules Ms in line with the June 30, 2008 period. The Schedule Ms related to property were then used to develop deferred income tax expenses and balances for June 2008 per normalization requirements.

Deferred Income Tax Expense and Balances (page 7.2) – The only deferred taxes included in the case are those associated with differences related to property, Investment Tax Credit (ITC), Malin Line Amortization, and SO2 emission allowances. The property-related deferred income tax expense was generated using the capital additions and resulting book and tax depreciation. Normalizing adjustments were added consistent with the Schedule M items. The deferred income tax expense was then used to develop the deferred tax balances for June 2008.

Taxes Other Than Income Taxes (page 7.3) – Page 7.3.1 shows a numerical summary of how Taxes Other than Income were adjusted from the historical level as of June 30, 2007 to the twelve months ending June 2008. Included in this summary are several adjustments including: Removal of Utah Gross Receipts Tax, Property Taxes, Low Income Tax Credit, and Washington Public Utility Tax. Property Taxes related to the removal of Colstrip Unit #3 are also removed in this section. Payroll tax expenses for the test period are included in O&M as part of the wage and benefit adjustment (Pages 4.2 and 4.3) as described above. The remaining miscellaneous taxes other than income were developed using June 2007 accruals and adjusting for known or anticipated changes through June 2008. The net-to-gross calculation incorporates some of the miscellaneous other taxes to add an incremental cost to the incremental revenue requirement.

Property Tax Expense (page 7.4) – Property tax expense for the twelve months ending June 2008 was developed by adjusting year-to-date accruals through June 30, 2007 for known or anticipated capital changes in assessment levels through June 2008.

Flow Through Deferred Taxes (page 7.5) **–** This adjustment reflects the removal of the June 2007 balances for all non-depreciation related deferred taxes, and the removal of the associated deferred tax expenses. This in effect flows through to income the current tax impacts on these items. This adjustment is incorporated into the deferred tax expense and balance summary on pages 7.2.1 through 7.2.12.

Malin Line Amortization (page 7.6) – In 1981, the Company built a transmission line called Malin-Midpoint and placed it into service. The Company was eligible for investment tax credits and accelerated tax depreciation. The Company entered into a Safe Harbor Lease transaction to transfer these tax benefits to an unrelated third party. As ordered in Docket UE-050684, the Company has treated this transaction as a sale of part of the benefits associated with the property and is amortizing the cash receipts over the life of the assets. The gain will be amortized over 30 years (composite book life of the plant) with a rate base deduction for the unamortized balance. In 1988, the substation was sold to Amoco and therefore the only amortization remaining is on the transmission line which is reflected in this adjustment.

Renewable Energy Tax Credit (page 7.7) – The Company is eligible for a federal income tax credit as a result of placing wind generating plants in service. The tax credit is based on the generation of the plants, and the credit can be taken for ten years on qualifying property. Under the calculation prescribed by Internal Revenue Service (IRS) Code Sec. 45(b)(2), the most current renewable electricity production credit is 2.0 cents per kilowatt hour of the electricity produced from wind energy. The impact of this adjustment on federal income tax expense can be found on page 2.22.

Utah Gross Receipts Tax Adjustment (page 7.8) – In 2006 the governor of Utah approved Utah House Bill 34 which repealed the gross receipts tax. The Company has removed this expense from its results.

Low Income Tax Credit (page 7.9) – This adjustment reduces the level of taxes included in the test period by the 2008 low income tax credit authorized by the Washington Department of Revenue.

Washington Public Utility Tax Adjustment (page 7.10) – This adjustment includes the additional Washington public utility tax expense based on the level of normalized revenues included in the test period.

Interest Synchronization (page 7.11) – Interest expense included in the test period was calculated by multiplying the total Washington allocated rate base by the weighted cost of debt. This calculation is shown on page 7.11.

Q. How are state income taxes treated in this filing?

A. No state income taxes are included in the calculation of Washington's revenue requirement. Under the West Control Area allocation methodology state income taxes are situs assigned based on each state's statutory tax rate. Since Washington has no state income tax, no state income tax expense is included in this filing.

Q. How have federal income tax expenses been calculated?

A. Federal income tax expense for ratemaking is calculated using the same methodology that the Company uses in preparing its filed income tax returns. The detail supporting this calculation is summarized on page 2.22.

Tab 8 – Rate Base

Q. Please describe how the Company developed the rate base projections used in the test period.

A. The detail for rate base for the test period is described in Tab 8. The key assumptions used in developing the test period rate base are summarized on page 8.0. The June 30, 2007 unadjusted balances, by FERC account, are included in the left-hand column of Pages 8.0.1 through 8.0.18. These pages summarize the incremental changes to walk rate base forward from June 30, 2007 to June 30, 2008 and show the rate base amounts included in the test period. The column "Jun 07 – Jun 08" is the average rate base summarized on pages 2.23 through 2.41 of Tab 2 - Results of Operations. Pages 8.0.19 through 8.0.54 detail each normalization adjustment made to rate base between June 30, 2007 and June 30, 2008.

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

A. **Cash Working Capital (page 8.1) –** In the last general rate case, Docket UE-061546, the Company proposed inclusion of cash working capital based on a Lead-Lag study methodology. Commission Staff proposed the calculation of cash working capital based on the investor supplied working capital formula (ISWC). Both proposals were rejected by the Commission in the final order in that proceeding which states:

> The problem here is that neither the Company nor Staff calculated working capital in a manner consistent with the WCA allocation methodology. Mr. Schooley, for Staff, testified that he performed his ISWC analysis on a total company basis, not a WCA basis, and then applied an allocation factor based on Washington plant relative to total system plant. This, he believes, "captures it to a certain degree."
>
> Mr. Wrigley, for PacifiCorp, testified that the Company relied on the same 2003 lead lag study putatively relied on in the 2005 rate proceeding. That study looked at PacifiCorp on a total Company basis and then performed an allocation based on either the revised protocol or modified accord allocation methodology. We expressly rejected the revised protocol in the 2005 Rate Case Order and the modified accord allocation methodology is obsolete.
>
> Due to the basic flaws in both parties' working capital analyses and assumptions, as in the prior case, we are unable to resolve the working capital issue here.

As a result of the Commission's decision, the Company has calculated cash working capital in this proceeding on the basis of the "1/8 of O&M" formula. This methodology divides total Washington allocated O&M expenses (less fuel and purchased power expenses) by eight, the approximate number of 45 day periods within a year. In addition to this calculation, the Company has removed all Washington allocated rate base balances for cash, working funds, notes receivable, other accounts receivable, accounts payable, fuel stock, materials and supplies, and prepayments. These adjustments to rate base are included as part of the Miscellaneous Rate Base adjustment found on page 8.5, which will be discussed later in my testimony.

The Company believes that this methodology is an acceptable alternative to the calculations previously rejected by the Commission. The Bonneville Power Administration (BPA) also uses this formula in the calculation of average system costs for investor owned utilities. This calculation can be found on page 8.1 of Exhibit No.___(RBD-2).

Jim Bridger Mine (page 8.2) – The Company 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. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base in order for the Company to earn a rate of return on its investment. The normalized coal costs for Bridger Coal Company in net power costs include the O&M costs of the mine, but provide no return on investment.

Customer Advances for Construction (page 8.3) – Customer advances were recorded in June 2007 unadjusted data to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation of customer advances for construction.

Plant Additions (page 8.4) – To provide a better match between the system infrastructure investment requirements and the load required to serve our customers, the Company has identified capital projects that will be completed by June 30, 2008. This information was provided by Company business units, which were asked to identify capital expenditures that will be used and useful prior to this date. Additions by functional category are summarized, indicating the in-service date and amount by project. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements as described in the depreciation section above. Although plant additions throughout the Company's six state service territory are shown in this section, only the additions applicable to the west control area have been included in the calculation of the Washington revenue requirement.

Miscellaneous Rate Base (page 8.5) – This adjustment removes cash, current assets (other working capital), fuel stock, material and supplies inventories and prepaid expenses from operating results. The Company is using the "1/8th of O&M" convention for calculating cash working capital, therefore all other components of working capital are being removed. This adjustment also removes miscellaneous deferred debit balances and miscellaneous rate base not authorized by the Commission.

Powerdale Hydroelectric Facility (page 8.6) – Powerdale is a hydroelectric generating facility located on the Hood River in Oregon. This facility was scheduled to be decommissioned in 2010; however, in 2006 a flash flood washed out a major section of the flow line. The Company determined that the cost to repair this facility was not economical and determined it was in our customers best interest to cease operation of the facility.

The Company petitioned the Commission in Docket UE-070624, for an Order (A) authorizing the Company to transfer its undepreciated net investment in the Powerdale Plant from FERC account 101 (EPIS), to FERC account 182.2 (unrecovered Plant and Regulatory study costs), (B) permitting the Company to record decommissioning costs in FERC account 182.2 and (C) authorizing the Company to establish amortization periods for these amounts. The Commission granted the Company's accounting request on October 27, 2007. This adjustment is consistent with the Commission’s order.

Removal of Colstrip Unit 4 AFUDC (page 8.7) – This adjustment removes AFUDC from plant in service for the period that Colstrip Construction Work in Progress (CWIP) was allowed in rate base. This treatment was authorized in Cause U-81-17 and has been included in all cases since its inception in July 1984.

Trojan Removal Adjustment (page 8.8) – This adjustment removes the Trojan amortization expense and the balance from results as ordered by the Commission in Docket UE-991832.

Customer Service Deposits (page 8.9) – This adjustment includes customer service deposits as a rate base deduction and also includes the interest paid on these deposits. This treatment was accepted by the Commission in its final order in Docket UE-061546.

Environmental Remediation (page 8.10) – On April 27, 2005 the Commission granted a request by PacifiCorp for an accounting order relating to the Company's treatment of environmental remediation costs in Docket UE-031658. The

Commission authorized the Company to record and defer costs prudently incurred in connection with its environmental remediation program. Additional costs of existing projects expected to exceed $3 million system-wide and incurred from October 13, 2003, the date the petition was submitted, through Fiscal Year 2005 will be deferred and amortized over a ten-year period. Currently only one project, the Third West Substation Cleanup, meets the criteria to be deferred. This adjustment removes the balance and amortization from FERC accounts 182.391 and 925, except for the amounts related to the Third West Substation Cleanup.

Retirements (page 8.11) – Retirement rates used in this filing were calculated using a five-year historical average of retirements. These rates are applied to the monthly pro forma plant balances to calculate plant retirements through June 30, 2008. The retirements reduce both electric plant in service and accumulated depreciation each month between July 2007 and June 2008

Q. Please describe the rest of Exhibit No.___(RBD-2).

A. **Tab 10, Allocation Factors**, summarizes the derivation of the jurisdictional allocation factors using the West Control Area allocation methodology. These factors are based on the loads, summarized in Tab 10 and the plant balances contained in Tab 2.

Q. From your analysis what do you conclude about the overall reasonableness of the Company's results included in this proceeding?

A. Based on Exhibit No.___(RBD-2), the Company will need the requested rate increase to recover its cost of serving Washington customers and provide a fair and equitable return for shareholders.

Q. Does this conclude your direct testimony?

A. Yes.