Q. Please state your name and business address with PacifiCorp dba Rocky Mountain Power ("the Company").

A. My name is Steven R. McDougal, and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah 84111.

Qualifications

Q. What is your current position at the Company, and what is your employment history?

A. I am currently employed as the director of revenue requirements for the Company. I have been employed by Rocky Mountain Power or its predecessor companies since 1983. My experience at Rocky Mountain Power includes various positions within regulation, finance, resource planning, and internal audit.

Q. What are your responsibilities as director of revenue requirements?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings or revenue requirement, assuring that the inter-jurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the Company operates.

Q. What is your education background?

A. I received a Master of Accountancy from Brigham Young University with an emphasis in Management Advisory Services in 1983 and a Bachelor of Science degree in Accounting from Brigham Young University in 1982. In addition to my formal education, I have also attended various educational, professional, and electric industry-related seminars.

Q. Have you testified in previous proceedings?

A. Yes. I have provided testimony before the Public Service Commission of Utah ("Commission"), the Washington Utilities and Transportation Commission, the California Public Utilities Commission, the Idaho Public Utilities Commission, the Oregon Public Utility Commission, the Wyoming Public Service Commission, and the Utah State Tax Commission.

Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. My direct testimony addresses the revenue increase requested in the Company's application and the calculation of the Company's Utah-allocated revenue requirement. In support of this calculation, I provide testimony on the following: Calculation of the $76.3 million requested rate increase.

- The test period utilized in this case, 12 months ending June 30, 2015 ("Test Period").
- The Company's process for compiling the Test Period revenue requirement and a detailed explanation of the normalizing adjustments made to the unadjusted base period data to arrive at the Test Period.
- The treatment of various items from the stipulation in the Company's last general rate case ("2012 GRC Stipulation") Docket No. 11-035-200 as approved by the Commission ("2012 GRC").
- The impact of the depreciation rates approved effective January 1, 2014, in the Company's recent depreciation study, Docket No. 13-035-02 ("2013 Depreciation Study"), on the depreciation expense reflected in the Test Period.

- The 2010 Protocol and Rolled-In inter-jurisdictional allocation methodologies as approved by the Commission.
- My testimony addresses the Company's proposal to revise Test Period results in the event the Environmental Protection Agency ("EPA") allows extension of Naughton Unit 3 as a coal-fired facility; the case is currently prepared under the assumption the unit will cease operations as a coal-fired facility in December 2014. A decision on this matter is expected from the EPA January 10, 2014.

Revenue Requirement Summary

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

A. At the current authorized rates, Rocky Mountain Power will earn an overall ROE in Utah of 8.5 percent during the Test Period. This is less than the 10.0 percent return recommended by Dr. Samuel C. Hadaway in this case and is less than the 9.8 percent return authorized by the Commission in the 2012 GRC. An overall price increase of $76.3 million is required to produce a 10.0 percent ROE under the 2010 Protocol allocation methodology. As I will explain later in my testimony, the same price increase is required when Utah revenue requirement is determined using the Rolled-In allocation methodology. Exhibit RMP___(SRM-1) provides a summary of the Company's Utah-allocated results of operations for the Test Period. Exhibit RMP___(SRM-2) provides a summary index identifying each normalizing adjustment and where each adjustment is addressed in the

Company's filing.[1] Details supporting the revenue requirement by FERC account and the allocation of the various revenue requirement components to Utah are provided in Exhibit RMP___(SRM-3).

Test Period and Revenue Requirement Preparation

Q. What test period did the Company use to determine revenue requirement in this case?

A. The Test Period utilized by the Company to calculate results of operations is based on the 12 month historical period ended June 30, 2013, ("Base Period") forecasted to the 12 month period beginning July 1, 2014, and ending June 30, 2015. Rate base is reflected on a 13-month average basis in the Test Period.

Q. Why did the Company use the 12 months ending June 30, 2015, as the Test Period?

A. Paragraph 41 of the 2012 GRC Stipulation states:

> The Parties agree that in the Company's 2014 GRC application, the Company will use, and the Parties will not oppose, use of a forecast test period of July 1, 2014 through June 30, 2015, with a 13-month average rate base, if the Company files its application prior to March 1, 2014.

On November 5, 2013, the Company filed with the Commission a notice of intent to file a general rate case and proposed a test period ending June 30, 2015, consistent with the 2012 GRC Stipulation. On December 10, 2013, the Commission issued an order approving the Company's test period. The order states:

> In light of the test year stipulation quoted above and the absence of opposition to the Company's proposed test year, we find the proposed test year meets the statutory requirements. See Utah

[1] In conformance with filing requirement R746-700-10.A.1.c.

> Code Ann. § 54-4-4(3). It is approved. Accordingly, consistent with Utah Administrative Code R746-700-10(B), the Company need not provide the alternative test period demonstration required by Subsection (A)(2) of that rule.

My testimony and exhibits provide a detailed explanation of all adjustments that were made to the Base Period data to accurately reflect the normal operating conditions the Company expects to occur during the Test Period.

Q. Does the Base Period match the unadjusted results of operations previously filed with the Commission?

A. Yes. The accounting data relied on for the Base Period in this case is the same data used for the unadjusted results of operations for the 12 months ended June 30, 2013, filed with the Commission in October 2013. However, the jurisdictional allocation model ("JAM") used for the rate case synchronizes interest and cash working capital for the unadjusted inputs while the JAM used for the results of operations does not. This synchronization of the unadjusted data produces an apparent difference between the two models for interest expense, current income taxes, and the cash working capital allowance.

Q. When will a rate change become effective in this proceeding?

A. The Company is requesting that new rates become effective September 1, 2014, which is 241 days after the submission date of this filing.

Q. What are the primary drivers of this case?

A. The primary drivers of the revenue increase requested in this case are the significant levels of capital investment the Company is making on behalf of customers, increases in depreciation expense reflecting new depreciation rates from the 2013 Depreciation Study and decreases in retail revenues and renewable energy credit ("REC") revenues. These are partially offset by higher wheeling revenues, reductions to operations, maintenance and administrative and general expense ("OMAG") and reduced Utah allocation factors resulting from the load forecast utilized in this case. Company witnesses Mr. Douglas N. Bennion, Mr. Chad A. Teply, Mr. Mark R. Tallman and Ms. Natalie L. Hocken provide testimony in support of the capital investments reflected in the Test Period required to serve customers. Ms. Kelcey A. Brown provides testimony on the load and retail sales forecast, Ms. Stacey J. Kusters' testimony supports the level of REC revenues included in the Test Period and my testimony summarizes the Test Period impact of applying the new depreciation rates.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Preparation of the revenue requirement began with historical accounting information; in this case, the Company used the 12 months ended June 30, 2013, as the Base Period for developing the revenue requirement in this case. Each of the revenue requirement components in the Base Period was analyzed to determine if an adjustment would be warranted to reflect normal operating conditions expected to occur during the Test Period. The Base Period data was adjusted to reflect known, measurable, and anticipated events and to include previously ordered Commission adjustments.

Q. Is the development of the Test Period in this case consistent with that of the Company's previous general rate cases in Utah?

A. Yes.

Q. What is the significance of Rocky Mountain Power's method of beginning with historical information to develop Test Period results?

A. The Company utilizes historical accounting information as the base and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical accounting data provides known operation and investment information that is readily available for audit by all participants involved in the case. Individual adjustments made to the historical accounting data in order to develop Test Period results are also available for review.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period results of operations.

A. Historical retail revenue is adjusted to reflect normal weather conditions and remove items that should not be included in the revenue requirement calculation. Revenue is also adjusted for the effect of applying the rates from the current Commission approved tariffs to the Test Period load projection. The testimony of Company witness Ms. Brown describes the comprehensive approach used to project Test Period loads for this case. Net power costs ("NPC") were developed using the Generation & Regulation Initiative Decision ("GRID") model, which has been used extensively in prior general rate cases and other regulatory proceedings in Utah. The calculation of Test Period NPC is described in the testimony of Company witness Mr. Gregory N. Duvall. Historical operations and maintenance ("O&M") expenses, excluding NPC, were split into labor and non-labor components. Non-labor costs were adjusted for projected price changes using nationally recognized inflation indices provided by IHS (formerly IHS

Global Insight) and for other discrete changes required to reflect conditions expected during the Test Period. Historical labor costs were also adjusted for expected wage and benefit changes through the end of the Test Period. Rate base was adjusted to capture planned additions to electric plant in service and known changes to other rate base items. In addition, asset retirements, removal costs, and accumulated depreciation balances were walked forward through the end of the Test Period by plant function. I explain the development of the Utah Test Period results of operations and specific adjustments in greater detail later in my testimony and exhibits.

Q. How has the Company addressed areas where the expected change in OMAG is different than the price changes projected by IHS?

A. The Company has identified costs that are projected to change in the future due to causes other than inflation. Specific adjustments for these items are included in the Test Period revenue requirement calculation. Testimony supporting these cost changes is provided as part of the Company's filing. An example of this type of adjustment is the Incremental O&M Adjustment, No. 4.9, which includes the cost of operating and maintaining the Company's generating plants.

Inter-Jurisdictional Allocations

Q. What allocation methodology did the Company use to calculate the Utah revenue requirement in this case?

A. The Company's requested price increase is based on the 2010 Protocol allocation methodology as described in the Agreement Pertaining to PacifiCorp's September 15, 2010, Application for Approval of Amendments to Revised Protocol

Allocation Methodology ("2010 Protocol Agreement") filed with the Commission on June 27, 2011, in Docket No. 02-035-04, and approved November 8, 2011. Consistent with the 2010 Protocol Agreement, allocation of results are based on the Rolled-In allocation methodology with the Hydro Endowment and Klamath adjustments, which are included in the 2010 Protocol, zeroed out. Consequently, Utah-allocated results of operation are identical under either the 2010 Protocol or the Rolled-In allocation methods. For comparison purposes, the Test Period results for this case in Exhibit RMP___(SRM-3) are provided using both the 2010 Protocol (Tab 2) and Rolled-In (Tab 9) methods. In addition, I have provided a calculation of the 2010 Protocol results including the Hydro Endowment and Klamath adjustments using Test Period information in (Tab 10) as required by the 2010 Protocol Agreement.

Docket No. 11-035-200 Stipulation

Q. Please describe how various items from the 2012 GRC Stipulation are included in this case.

A. The stipulation reached by parties in the 2012 GRC addressed several items that impact the development of the Test Period results and revenue requirement in this case. Below I address how certain of these items were reflected in the development of the Test Period results or where further information on treatment of these items in the case can be found.

<u>REC Revenues</u>

Paragraph 39 of the 2012 GRC Stipulation allows the Company to retain 10 percent of REC sales revenue pursuant to terms specified in the stipulation. The

Company has not reflected REC revenue retention in the Test Period results, but rather intends to address this issue in the upcoming REC Balancing Account ("RBA") filing in March 2014. The results in this GRC filing reflect REC revenues at the level expected during the Test Period as supported by the testimony of Company witness Ms. Kusters. Further detail on this issue may be found in REC Revenue Adjustment, No. 3.4. of my Exhibit RMP___(SRM-3).

<u>Depreciation Study</u>

Depreciation expense levels and accumulated depreciation reserve balances included in Test Period results reflect the impact of the new depreciation rates established in the 2013 Depreciation Study, including the excess reserve givebacks for Steam plant and Utah distribution plant. Paragraph 44 of the 2012 GRC Stipulation addresses the treatment of the net difference in depreciation expense resulting from the application of new depreciation rates until they are reflected in base retail rates. The stipulation allows deferral for future recovery of any aggregate net increase in Utah-allocated depreciation expense in excess of $2.0 million annually. The new depreciation rates result in an aggregate net increase in Utah-allocated depreciation expense. As detailed in Deprecation Study Adjustment, No. 6.3 of Exhibit RMP___(SRM-3), the Company has projected the level of depreciation expense to be deferred from January 1, 2014, through August 31, 2014, and has reflected in Test Period results amortization of this deferral beginning September 1, 2014, and continuing through June 30, 2015. My testimony describes the treatment of these items in the Test Period revenue requirement as detailed in Tab 6 of Exhibit RMP___(SRM-3).

Paragraph 45 of the 2012 GRC Stipulation specifies the Company will propose a class cost of service allocation of the deferred depreciation expense to customers as part of the this rate case. This matter is addressed in the testimony of Company witness Ms. Joelle R. Steward.

<u>Carbon Plant</u>

Paragraphs 46 through 50 of the 2012 GRC Stipulation address matters raised in Docket No. 12-035-79 concerning retirement and decommissioning of the Carbon plant. Among other items, the 2012 GRC Stipulation specifies: (i) creation of the Remaining Carbon Balances regulatory asset to be amortized from the date Carbon plant net balances are transferred to the regulatory asset through calendar year 2020; (ii) creation of the Carbon Removal Costs regulatory asset to be recovered from customers from the time the plant is retired (currently projected to occur in April 2015) through calendar year 2020; (iii) agreement by the parties to not challenge recovery of the Remaining Carbon Balances regulatory asset on the grounds of used and useful standards; (iv) the Company is required to propose updates to the Carbon Removal Costs regulatory asset in each future rate case filing, based on the best available cost removal projections;. and (v) any changes to projected Carbon Removal Cost estimates will be identified and explained as part of each future rate case filing, including this rate case.

Later in my testimony, I describe the treatment of the Remaining Carbon Balances regulatory asset in Test Period results. Further detail on this item may be found in Carbon Plant Adjustment, No. 8.13 of Exhibit RMP___(SRM-3). Concerning the Carbon Removal Costs regulatory asset, the Company is proposing in this case to defer any recovery and amortization of this balance until the next general rate case filing. Deferral of this matter to the next general rate case will ensure that amortization of removal costs do not begin until decommissioning activities have commenced and will also enable the Company to develop a more current removal cost estimate prior to inclusion in customer rates. At this time, the Company does not have a more current estimate of Carbon removal costs than the $117/kw figure that was utilized in the 2013 Depreciation Study.

<u>Naughton Unit 3 Development Costs</u>

Paragraphs 52 and 53 of the 2012 GRC Stipulation specifies treatment of the Naughton Unit 3 development costs for which the Company requested deferred accounting treatment in Docket No. 12-035-80. Pursuant to the stipulation, Utah's allocated share of the Naughton Unit 3 development costs of $7.9 million would be deferred and fully amortized by September 1, 2014, providing full recovery prior to the effective date of this rate case. As addressed later in my testimony, Naughton Write-off Adjustment, No. 4.10 of Exhibit RMP___(SRM-3) removes amortization of the Naughton Unit 3 development costs from Test Period results ensuring the amortization is not reflected in the requested revenue requirement.

<u>Klamath</u>

Paragraphs 58 through 60 of the 2012 GRC Stipulation address the revenue requirement treatment of various items related to the Company's Klamath hydroelectric facility. Among other items, the stipulation specifies: (i) the Company is permitted to fully depreciate the Klamath dam facilities through 2022 beginning June 1, 2012; (ii) the Company may recover a return on and return of the Klamath dam balances by including depreciation expense and net unrecovered plant rate base in results through calendar year 2022, even if the plant is decommissioned prior to 2022; (iii) the Klamath related relicensing and process costs of $81.8 million are included in Utah rates through amortization of the balance through 2022, beginning October 12, 2012, with a carrying charge set at the long term cost of debt. Since a carrying charge is reflected in the amortization expense, the relicensing and process cost asset is not included in rate base; and (iv) the Company may not recover from Utah customers dam removal or removal related costs associated with the Klamath Hydroelectric Settlement Agreement ("KHSA"). The Test Period treatment of these items is addressed later in my testimony and in Klamath Hydroelectric Settlement Agreement Adjustment, No. 8.11 found in Exhibit RMP___(SRM-3).

Utah Solar Program

Paragraph 61 of the 2012 GRC Stipulation specified that costs for the Utah Solar Incentive Program, which was being developed and was not approved by the Commission at the time the stipulation was written, be added as a surcharge to the Step 1 rate increase of the 2012 GRC effective October 12, 2012. The program was subsequently approved in Docket No. 11-035-104. In the order approving the program, a separate rate schedule (Schedule 195) was developed to recover the revenue requirement of this program. Schedule 195 charges are added to the energy charges of each customer's applicable tariff rate schedule. Accordingly, costs associated with this program are excluded from the Test Period results.

Utah Results of Operations

Q. Please describe Exhibit RMP___(SRM-3).

A. Exhibit RMP___(SRM-3), which was prepared under my direction, is Rocky Mountain Power's Utah results of operations report ("Report"). The historical starting point for the Report is the 12 months ended June 30, 2013, which was normalized and then projected forward to calculate the revenue requirement for the Test Period, 12 months ending June 30, 2015. The Report provides totals for revenue, expenses, depreciation, net power costs, taxes, rate base, and loads in the Test Period. Rate base has been walked forward through the Test Period using a 13-month average methodology. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit RMP___(SRM-3) is organized.

A. The Report is organized into sections marked with tabs. Tab 1 Summary contains the Utah-allocated results according to the 2010 Protocol Agreement. Page 1.0 summarizes the revenue requirement calculation based on the Utah's results of operations for the Test Period. The Total Adjusted Results column is carried forward from the results of operations summary, page 2.2, and shows an ROE for Utah of 8.5 percent. The Price Change (column 2 of Tab 1, page 1.0) shows that an increase of $76.3 million in revenue is required to increase the ROE from 8.5 percent to 10.0 percent. Column 3 reflects Utah's adjusted revenue requirement of $1.96 billion with the $76.3 million price increase included. Page 1.1 of Tab 1 supports the calculation of additional revenue related uncollectible expense and income taxes associated with the price change. Page 1.2 details the calculation of the net operating income percentage. Page 1.3 shows the same details as page 1.0 but under the Rolled-In rather than the 2010 Protocol allocation methodology. This sheet is provided to show that results are identical under either method, consistent with the 2010 Protocol Agreement. Pages 1.4 through 1.5 contain a summary of adjustments made to the actual results to arrive at the normalized results of operations for the Test Period.

Tab 2 details total-Company and Utah-allocated results based on the 2010 Protocol Agreement. Pages 2.3 through 2.39 contain total-Company and Utah-allocated revenue, expenses and rate base detail by FERC account. Actual results of operations are supplied side-by-side with the normalized Test Period results, on both a total-Company and Utah-allocated basis.[2] Supporting documentation for the data in Tab 2, along with the normalizing adjustments required to reflect on-going costs of the Company, is provided under Tabs 3 through 8. These adjustments are described later in my testimony. Tab 9 is Tab 2 restated with the Utah allocation based on the Rolled-In allocation methodology. Tab 10 is Tab 2 restated with the Utah allocation based on the 2010 Protocol allocation methodology including a dynamic Embedded Cost Differential adjustment ("ECD"). Tab 11 contains the calculation of the 2010 Protocol allocation factors and the Hydro Endowment component of the ECD.

At the beginning of each tabbed section, a summary document is provided which directs the reader to where the underlying electronic workpapers utilized to develop the content in each section can be located in the Company's filing.[3]

[2] In conformance with filing requirement R746-700-22.B.1.
[3] This is provided in compliance with R746-100-3.C.

Tab 3 – Revenue Adjustments

Q. Please describe the information contained behind Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index, which is a list of adjustments used to project retail revenue for the Test Period. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenue and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), which contains a summary showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to revenue in Tab 3.

A. **Pro Forma Revenue (page 3.1) –** This adjustment begins with June 30, 2013, general business revenues and adjusts to the pro forma level for the Test Period based on Commission authorized tariffs applied to forecasted loads. Revenue for the Company's other jurisdictions during the Test Period is also computed using current rates in the respective states. Several items are removed from actual booked revenue that should not be included in Test Period results including special contract buy-through revenue, deferred net power costs, demand side management (Schedule 193) revenue, Utah solar program (Schedule 195) revenue, and out-of-period adjustments to revenue. Test Period revenue reflects the recent changes to base rates approved in the 2012 GRC, including the Step 1 rate change effective October 12, 2012, the Step 2 rate change effective September 1, 2013, and special contract changes effective January 1, 2014.

Wheeling Revenue (page 3.2) – This adjustment reflects the projected level of wheeling revenue for the Test Period by adjusting the actual Base Period revenue for normalizing, annualizing, and pro forma changes. On May 23, 2013, a settlement agreement reached in the Company's transmission rate case, FERC Docket No. ER11-3643 ("FERC Rate Case"), was approved by the Federal Energy Regulatory Commission ("FERC"). This adjustment incorporates into Test Period results the revenue impact associated with the changes to the Open Access Transmission Tariff ("OATT") resulting from the settlement agreement as approved by FERC. Paragraph 51 of the 2012 GRC Stipulation specifies that incremental wheeling revenues resulting from the FERC Rate Case will be deferred from July 1, 2012, through the effective date of this rate case (September 1, 2014) and included as a 100 percent pass-through credit in the Company's Energy Balancing Account ("EBA") application subsequent to FERC's final order in the FERC Rate Case. Pursuant to the terms of the 2012 GRC Stipulation, the Company's EBA application filed in March 2014 will reflect a credit for deferred wheeling revenues.

SO2 Emission Allowances (page 3.3) – The Environmental Protection Agency ("EPA") has established guidelines that govern the volume of sulfur dioxide ("SO_2") that can be emitted from power plants and granted the issuance of SO_2 emission allowances to cover each ton emitted. Plants that are not in compliance with EPA guidelines may purchase emission allowances from other companies that have excess allowances. Consistent with the Commission order in Docket No. 97-035-01, the Company has amortized sales of emission allowances over a four-year period. This adjustment replaces the sales from the historical period with the appropriate annual amortization, taking into account projected sales through the Test Period.

REC Revenue (page 3.4) – RECs represent the environmental attributes of electricity produced from renewable energy facilities and can be detached from the electricity commodity and sold separately. RECs may also be used to meet renewable portfolio standards ("RPS") in various states. To comply with current or future year RPS requirements in California, Oregon, and Washington, the Company does not sell RECs that are eligible for RPS requirements in those states. This adjustment ensures Test Period REC revenues are correctly allocated among the Company's jurisdictions after considering the banking of eligible RECs for RPS compliance purposes. Company witness Ms. Kusters' testimony supports the development of the total-Company REC revenue forecast for the Test Period. In addition, this adjustment removes REC deferrals reflected in Base Period results consistent with the treatment of NPC deferrals in the Net Power Cost Adjustment, No. 5.1. Differences between REC revenues reflected in rates and actual REC revenues received are accounted for in the RBA, which the Company files on an annual basis.

Joint Use Revenue (page 3.5) – This adjustment reflects a change to Joint Use Revenue, Schedule 4, resulting from a proposed decrease in the attachment rate from $6.33 to $5.76 per pole. The amount proposed by the Company is calculated in accordance with Commission Rule R746-345-5. Company witness Mr. Jeffery M. Kent provides additional supporting detail in his testimony.

Ancillary Revenue (page 3.6) – This adjusts other electric revenue to account for ancillary services contracts that will expire before or during the Test Period. The Foote Creek 2 contract expires before the beginning of the Test Period and the Foote Creek 3 contract expires effective July 2014. Revenues from these contracts are removed from Test Period results (other than one month of revenue associated with the Foote Creek 3 contract) since revenue will not be received during the Test Period due to expiration of these contracts.

Tab 4 – Operation and Maintenance (O&M) Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes the Operation and Maintenance Expense Adjustment Index followed by a numerical summary and the specific adjustments. The numerical summary (pages 4.0.2 – 4.0.3) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), which contains a summary showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

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

A. **Miscellaneous General Expense (page 4.1) –** This adjustment removes certain miscellaneous expenses from the Base Period results that should have been charged below-the-line to non-regulated expense. It also reallocates certain gains and losses on property sales included in Base Period results to reflect the appropriate allocation.

Wage & Employee Benefits (page 4.2) – Labor related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, post-employment benefits and other benefits for changes expected beyond the actual costs experienced in the Base Period. Company witness Mr. Erich D. Wilson's testimony provides an overview of the compensation and benefit plans provided to employees and supports the costs included in the Test Period.

Collective bargaining agreements are used to escalate union wages where increases are specified, and wage increases for non-union and exempt employees are based on the Company's targets. Incentive compensation for non-union employees is included in Test Period results using a three-year historical average, calculated by multiplying the pro forma wages in this case by the three-year historical average of the actual payment rate. Pension expense and other employee benefit costs are adjusted to the planned expense levels for the Test Period, based on actuarial reports where available or by escalating actual costs. Pension administrative costs are based on a three year historical average.

Page 4.2.1 of Exhibit RMP___(SRM-3) provides further description of the procedure used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual labor costs in the Base Period and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Idaho Irrigation Load Control Program (page 4.3) – Incentive payments made to Idaho customers participating in the irrigation load control program and a portion of the program's administrative costs are initially system allocated in unadjusted accounting data. Consistent with the 2010 Protocol, demand-side management ("DSM") program costs are situs assigned to the states in which the costs are incurred to match the benefit of reduced load reflected in the inter-jurisdictional allocation factors. This adjustment corrects the booked allocation to assign these costs directly to Idaho.

Remove Non-Recurring Entries (page 4.4) – A few accounting entries were made to expense accounts during the Base Period that are non-recurring in nature, or relate to a prior period. These items, which include an adjustment to remove the costs related to the Pilot Solar Photovoltaic Incentive Program, which has been superseded by the Schedule 107 Solar Incentive Program, are removed from results of operations to normalize Test Period results. Details on the specific items in the adjustment can be found on page 4.4.1.

Uncollectible Accounts (page 4.5) – Expense for uncollectible accounts is adjusted to the Test Period level by applying the historical uncollectible rate to the normalized general business revenue in the Test Period. The rate is calculated by dividing the Utah uncollectible accounts expense in FERC account 904 by the Utah general business revenues. This treatment is the same methodology used in Dockets No. 10-035-124 and No. 11-035-200 (the Company's last two general rate case filings).

DSM Expense (page 4.6) – This adjustment removes expenses related to DSM programs in various states because these costs are recovered via separate surcharges and are not included in base rates. In Utah, these costs are recovered through the Demand Side Management Cost Adjustment, Schedule 193. The associated DSM revenues are removed in Pro Forma Revenue Adjustment No. 3.1.

Insurance Expense (page 4.7) – This adjustment normalizes insurance expense related to third-party liability for injuries and damages as well as damage to Company property. Injuries and damages expense is set at the three-year historical average using the cash method, consistent with the Utah Commission ruling in Docket No. 07-035-93.

Insurance expense for damage to Company property is currently accrued to a reserve account. This treatment for property damage expense was included in Dockets No. 10-035-124 and No. 11-035-200. The balance of the reserve account at June 2013 was $1.6 million. The Company believes this is a reasonable reserve level, so no adjustment to the property damage accrual is proposed in this case.

In addition, this adjustment removes an out-of-period allocation correction for an injuries and damages accrual and also removes accounting entries booked in the Base Period related to the California Catastrophic Event Memorandum Account regulatory asset that should not be reflected in Utah results.

Generation Overhaul Expense (page 4.8) – This adjustment normalizes generation overhaul expense using a four-year historical average for the 12 month periods ending June 2010 through June 2013. For Lake Side 2, scheduled to be placed in service June 2014, the four-year average is comprised of the overhaul expense planned for the first four full years the plant is operational. Prior to averaging, annual expenses are restated to June 2013 dollars to make the dollars comparable. A four-year average is consistent with the normalized outages assumed in the GRID model to compute Test Period net power costs.

Use of a four-year historical average to set overhaul costs in customer rates was approved by the Commission in Docket No. 07-035-93, as was the use of a four-year average of projected expenses for the Company's new gas plants. The use of a four-year average methodology has been utilized in all Company rate case filings since the 07-035-93 case. However, the Commission rejected the treatment of restating the annual components of the average to constant dollars prior averaging in the 07-035-93 and 09-035-23 cases; settlement agreements, which did not address this matter, were reached in the remaining cases. The Company continues to believe that the purpose of averaging is to adjust for uneven costs, and that without the restatement to constant dollars in the average calculation, overhaul expenses reflected in rates will be systematically understated.

New evidence in support of this position has been presented in the 10-035-124 and 11-035-200 cases, but was not heard by the Commission as settlement agreements were reached in those proceedings. In both the 10-035-124 and 11-035-200 cases, the Division of Public Utilities ("DPU") provided testimony in support of restating annual expenses to constant dollars prior to averaging.[4] DPU witness Dr. William Powell correctly pointed out that from an economic standpoint, averaging dollars from multiple years requires the dollars to be stated on a consistent basis prior to averaging. On lines 139 – 143 of his direct revenue requirement testimony in Docket 11-035-200, Dr. Powell states:

[4]Direct testimony of Dr. William Powell, Docket No. 10-035-124, lines 443 – 560. Direct testimony of Dr. William Powell, Docket No. 11-035-200, lines 94 – 203.

> First, economic theory suggests that in order to compare two values separated by time, the values need to have a common monetary base. That is, the values should be expressed in real terms, where the effects of inflation are taken into account, as opposed to nominal terms. Comparing values expressed in nominal terms—ignoring inflation—can lead to erroneous conclusions.

The Company agrees with Dr. Powell's statement in this regard. A simple example below shows the impact of averaging, assuming a 2.5 percent inflation rate, a $100 amount in year one, and a four-year average of years one through four used to project costs in year five. Using this assumption, Example 1 shows the impact without adjusting for inflation and Example 2 shows the impact when years one through four are stated in real or constant dollars.

As shown in the first example, with no restatement to account for inflation, a four-year average of costs is $103.8, much less than the projected costs in year five, resulting in an expense level that is 2.5 years old compared to the current expenses. In Example 2, the average is equal to the year five amount resulting in an accurate forecast.

Example 1

Year	Amount	
1	$ 100.0	
2	102.5	Average
3	105.1	$103.8
4	107.7	
5	110.4	

Example 2

Year	Amount	Escalation	Adjusted Amount	
1	$ 100.0	1.104	$ 110.4	
2	102.5	1.077	$ 110.4	Average
3	105.1	1.051	$ 110.4	$110.4
4	107.7	1.025	$ 110.4	
5	110.4			

Incremental O&M (page 4.9) – This adjustment accounts for changes in costs at the Company's thermal, hydro, and wind generation plants due to changes in operations and regulatory requirements. Support for the thermal generation costs reflected in this adjustment is provided in the testimony of Company witness Mr. Dana M. Ralston. Consistent with the treatment proposed in my rebuttal testimony in the 2012 GRC, wind plant oil change costs for the Test Period are reflected on a three-year average basis in the wind generation O&M included in this adjustment.

Naughton Unit 3 Write-Off Adjustment (page 4.10) – As stated in the 2012 GRC Stipulation, recovery for Utah's allocated share of the Naughton Unit 3 development costs is to be deferred and fully amortized by September 1, 2014, prior to the effective date of this general rate case. Therefore, this adjustment removes the regulatory asset, related amortization, and the write-off expenses reflected in the Base Period associated with this matter.

O&M Expense Escalation (page 4.11) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Projected increases or decreases in costs are based on IHS indices, which provide a detailed assessment of the electric market both historically and into the future. The indices used are based on electric utility costs for materials and services only, which exclude labor expense, according to the Uniform System of Accounts defined by FERC for major electric utilities.

The IHS indices are prepared at the FERC functional subcategory and are denoted with their corresponding FERC account number. The individual FERC account indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses. The IHS study used to prepare this filing was the third quarter 2013 forecast, released November 4, 2013. The IHS data is proprietary and subject to copyright protection, therefore the indices utilized in the Company’s case are provided in Confidential Exhibit

RMP___(SRM-4).

Tab 5 – Net Power Cost Adjustments

Q. Please describe the information contained behind Tab 5 Net Power Cost Adjustments.

A. The Net Power Cost Adjustment Index on page 5.0.1 is a numerical summary of adjustments made to NPC related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3) which contains a summary showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **Net Power Cost Study (page 5.1) –** The NPC study presents normalized Test Period steam and hydro power generation, fuel, purchased power, wheeling expense and sales for resale based on the Company's GRID model. It also normalizes hydro generation, weather conditions and plant availability as described in the testimony of Company witness Mr. Duvall.

James River Royalty Offset (page 5.2) – On January 13, 1993, the Company executed a contract with James River Paper Company ("James River") 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 an offset to royalties paid to James River. The contract costs of energy for the Camas unit are included in the Company's NPC as purchased power expense, but GRID does not include an offsetting revenue credit for the capital and maintenance cost recovery. This adjustment adds the royalty offset to FERC Account 456, Other Electric Revenue, for the Test Period.

Little Mountain (page 5.3) – The Little Mountain plant is an electric generation facility located near Ogden, Utah, which ceased operations on May 31, 2013. This adjustment removes the steam revenues, depreciation, and O&M expense incurred in the Base Period, as well as plant and depreciation reserve balances to reflect the retirement and decommissioning of the Little Mountain plant in Test Period results.

Tab 6 – Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The summary on page 6.0.1 is an index of adjustments to depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), which contains a summary showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1) –** The depreciation and amortization expense for the Test Period is calculated by applying functional composite depreciation and amortization rates to projected plant balances by month. Depreciation related to pro forma capital additions is computed from the date the depreciable asset is placed into service. Depreciation rates set in the 2013 Depreciation Study are used to develop Test Period depreciation expense. Depreciation expense prior to January 1, 2014, which impacts the depreciation reserve balance developed in this case, is calculated using rates approved in Docket No. 07-035-13. Depreciation expense also includes the accrual for hydro decommissioning. Details are provided on pages 6.1.2 through 6.1.17.

Depreciation and Amortization Reserve (page 6.2) – Accumulated depreciation and amortization balances for the Test Period are calculated by walking the June 2013 13-month average actual reserve balances forward using the pro forma depreciation and amortization expense, plant retirements and removal costs as calculated in the Depreciation and Amortization Expense Adjustment (page 6.1) and the Pro Forma Plant Additions and Retirements Adjustment (page 8.6). Accruals and planned spending for hydro decommissioning are also included in the adjusted depreciation reserve balance. The reserve balances are calculated on a monthly basis through June 30, 2015, as detailed on pages 6.2.2 to 6.2.11. Consistent with electric plant-in-service, the accumulated depreciation and amortization reserve balance included in Test Period rate base is stated on a 13-month average basis.

Depreciation Study (page 6.3) – This adjustment incorporates into Test Period results the impacts of the 2013 Depreciation Study. Pursuant to the Commission's order in that docket, new depreciation rates and other components of the depreciation study became effective January 1, 2014. The depreciation and amortization expense for the Test Period calculated in Adjustment 6.1 reflects the new depreciation rates and Adjustment 6.2 reflects the accumulated reserve impact of the new rates beginning January 2014. This adjustment captures other elements of the depreciation study that are not reflected elsewhere in the development of Test Period results.

The new depreciation rates approved by the Commission result in a net increase to Utah-allocated depreciation expense. Paragraphs 43 through 45 of the 2012 GRC Stipulation specify the treatment of 2013 Depreciation Study items to be included in this rate case. As addressed in paragraph 44 of the stipulation, any aggregate net increase in Utah-allocated depreciation expense in excess of $2.0 million annually may be deferred for future recovery. The period of deferral begins when the new depreciation rates became effective (January 1, 2014) until the new rates are reflected in customer rates. To calculate this deferral for inclusion in Test Period results, both the depreciation rates in effect prior to January 2014 and those effective beginning in January 2014 going forward were applied to projected Electric Plant in Service balances on a monthly basis from January 2014 through August 2014. The variance between the old and new rates totaled approximately $5.0 million from January to August 2014. To this balance, the $2.0 million annual deadband was applied at a rate of $166,667 per month ($2.0 million divided by 12-months) to calculate the balance allowed for deferral. As allowed in paragraph 45 of the 2012 GRC Stipulation, the deferred depreciation expense balance is amortized through June 30, 2031, beginning September 1, 2014. Amortization of the deferred depreciation expense balance adds $178,159 of amortization expense to Utah-allocated Test Period results. No carrying charge is allowed on the deferred balance, pursuant to paragraph 45 of the 2012 GRC Stipulation, so a regulatory asset for the deferred balance is not reflected in the adjustment.

The details of this calculation are provided on pages 6.3.2 through 6.3.6 of Exhibit RMP___(SRM-3). This methodology is consistent with Exhibit C to the 2012 GRC Stipulation which was provided in that proceeding to detail the calculation of the depreciation deferral amortization. Paragraph 45 of the stipulation also specified that the Company agrees to propose an allocation of any deferred amount in this rate case. This is addressed in the testimony of Company witness Ms. Steward.

In addition, this adjustment reflects into Test Period results excess reserve amortizations identified in the 2013 Depreciation Study. Excess reserves were identified for both steam and distribution plant and are addressed by crediting depreciation expense with an offsetting debit to the depreciation reserve. Excess reserves were identified for the Hunter, Gadsby, Colstrip and Blundell steam plants in addition to Utah distribution plant. In total, the steam plant excess reserve Test Period amortization is $11.3 million (total-Company basis) whereas the Utah distribution plant Test Period amortization is $23.1 million. The amortization period for the steam balance varies by plant; the Utah distribution balance is to be amortized over 6.5 years. Amortization for both the steam and distribution items begins January 1, 2014. Additional detail on these items can be found in paragraphs 21, 22 and 23 of the 2013 Depreciation Study stipulation. This adjustment also reflects into Test Period results the change in vehicle depreciation resulting from rate changes in the 2013 Depreciation Study.

Tab 7 – Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index (page 7.0.1) followed by a numerical summary and the specific adjustments. The numerical summary (pages 7.0.2 – 7.0.3) identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), which contains a lead sheet showing the affected FERC account(s), allocation factor, dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1) –** Details the adjustment to interest expense required to synchronize the Test Period expense with rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2) – Property tax expense for the Test Period was computed by adjusting actual property tax expense for known or anticipated changes in assessment levels through June 30, 2015. The property tax expense in this case was estimated using methods similar to those employed by the Company in previous rate cases. These methods give necessary consideration to the effect that changes in the level of operating property and net operating income may have on state-by-state assessed values. Confidential Exhibit RMP___(SRM-5) provides a comprehensive description of the Company's property tax estimation procedures along with a detailed calculation of Test Period property taxes.

Renewable Energy Tax Credit (page 7.3) – The Company is eligible to recognize certain federal income tax credits as a result of placing qualifying renewable generation plants into service. The federal tax credit is based on the kilowatt-hours of generation from those plants, and may be taken for 10 years on qualifying property. Under the calculation required by Internal Revenue Service Code Sec. 45(b)(2), the current renewable electricity production credit is 2.3 cents per kilowatt hour of generation.

Allowance for Funds Used During Construction ("AFUDC") Equity (page 7.4) – This adjustment aligns the amount of AFUDC equity in regulatory income with the related tax Schedule M item. Consistent with the stipulation approved by the Commission in Docket No. 09-035-03, AFUDC equity is treated on a flow through basis rather than normalized for tax purposes.

Repairs Deduction Deferred Accounting (page 7.5) – As a result of a stipulation in Dockets No. 09-035-03 and No. 09-035-23 regarding income tax treatment, a regulatory liability equal to the revenue requirement impact of the difference in the deduction for repairs recognized in regulatory results versus recognized for tax return purposes for calendar years 2009 and 2010 was to be included in rate base and amortized over a period of not more than five years. Given the magnitude and direction of this amortization, the Company amortized this item over one year in the 2012 GRC. This adjustment removes the regulatory liability remaining on the books during the Base Period from Test Period results.

Pro Forma Schedule M's (page 7.6) – The Base Period Schedule M items were updated for known and measurable adjustments through the Test Period. Non-utility items, separate tariff items, and other non-recurring items were removed from the historical period before updating. The Schedule M items were then used to develop deferred income tax expenses and balances for the Test Period.

Pro Forma Deferred Tax Expense (page 7.7) – Non-property related Schedule M items in the Test Period were used to develop the deferred income tax expense. 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.

Pro Forma Deferred Tax Balance (page 7.8) – The deferred income tax expense was used to develop the deferred tax balances for the Test Period. This adjustment normalizes the accumulated deferred income tax balances to the estimated pro forma 13-month average rate base balance for the Test Period. The allocation of property related deferred income tax balances are also updated consistent with the Company's model using the Power Tax fixed asset software system.

Recently, Congress reinstated bonus depreciation for the calendar year 2013. For qualified property placed in service before January 1, 2015, 50 percent of the tax basis in construction work in progress at December 31, 2013, is deductible as bonus depreciation. The deferred tax balances reflected in the Test Period include the tax benefits of the recently reinstated bonus depreciation.

Wyoming Wind Generation Tax (page 7.9) – The Wyoming wind generation tax is an excise tax levied upon electricity generated from wind resources in the state of Wyoming. The tax is on the production of electricity from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the entity producing the electricity. The tax is one dollar on each megawatt hour of electricity produced from wind resources at the point of interconnection with an electric transmission line. The tax begins three years after the in-service date of the wind turbine. For the Test Period, all of the production from the Company owned Wyoming wind turbines qualifies and are therefore subject to this tax. This adjustment normalizes the Wyoming wind generation tax into the Test Period results.

Tab 8 – Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The summary begins on page 8.0.1 with an index of adjustments made to electric plant in-service and other rate base components. The numerical summary (pages 8.0.2 – 8.0.3) identifies each adjustment made to rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in Exhibit RMP___(SRM-3), which contains a summary showing the affected FERC account(s), allocation factor, dollar amount and a brief description of the adjustment.

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

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital included in results based on the normalized results of operations for the Test Period. Cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on the lead lag study prepared by the Company using calendar year 2012 information. A complete copy of the 2012 study is provided as part of the Company's response to filing requirement R746-700-22.D.43. Based on the results of the lead lag study the Company experiences 5.99 net lag days in Utah and requires a cash working capital balance of $22.0 million in rate base.

Trapper Mine Rate Base (page 8.2) – The Company owns a 21.4 percent share of the Trapper Mine, which provides coal to the Craig generating plant. This investment is accounted for on the Company's books in account 123.1, investment in subsidiary company, which is not included as a rate base account. The normalized coal cost from Trapper Mine in net power costs includes operation and maintenance costs, but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine net plant investment to rate base in order for the Company to earn a return on its investment.

Jim Bridger Mine Rate Base (page 8.3) – The Company owns a two-thirds interest in the Bridger Coal Company which supplies coal to the Jim Bridger generating plant. Due to the ownership arrangement, the mine investment is not included in the Company's unadjusted results of operations, and the normalized coal costs for Bridger include all operating and maintenance costs but do not include a return on investment. This adjustment adds the Company's portion of the Bridger Mine net plant investment to rate base in order for the Company to earn a return on its investment.

Plant Held for Future Use (page 8.4) – This adjustment removes certain Plant Held for Future Use ("PHFU") assets from FERC account 105. In my rebuttal testimony in the 2012 GRC, the Company agreed to remove the Twelve Mile, Wild Horse, Aeolus, Anticline, and Populus properties from PHFU. The Company continues to believe it is appropriate to exclude these items from rate base. However, the Company continues to assess these properties for appropriate inclusion in rate base and will propose rate base treatment for these items once it is determined that they are appropriately includable in rate base.

Customer Advances for Construction (page 8.5) – Refundable customer advances for construction are booked to FERC account 252. The Base Period balances do not reflect the proper allocation because amounts were recorded to a corporate cost center location rather than state specific locations in the Company's accounting system. This adjustment corrects the allocation of customer advances.

Pro Forma Plant Additions and Retirements (page 8.6) – To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be placed in-service by the end of the Test Period. Company business units identified capital expenditures that will be placed into service prior to the end of the Test Period. Additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Plant additions are included on a 13-month average basis in the Test Period. Descriptions of large individual projects are included on pages 8.6.31 through 8.6.39.

Plant retirements were applied to pro forma plant balances to reflect ongoing asset retirements through the Test Period. Retirement levels were calculated using a normalized five-year average methodology. This adjustment incorporates these retirements into Test Period electric plant in-service balances. A corresponding entry to accumulated depreciation and amortization is included in the calculation of Test Period reserve balances in the Depreciation and Amortization Reserve Adjustment (page 6.2). In addition, plant removal costs are reflected into Test Period results through this adjustment. The Company used a five-year average to project removal costs in the Test Period incurred in capital projects where existing infrastructure must be removed prior to construction of the new asset. Removal costs are booked as a reduction or (credit) to electric plant in service and a reduction (or debit) to accumulated depreciation reserve when incurred. The impact of removal costs is reflected in the Depreciation and Amortization Reserve Adjustment (page 6.2).

Miscellaneous Rate Base (page 8.7) – This adjustment reflects the Test Period level of fuel stock balance in results based on projected inventory by plant, along with offsetting working capital deposits. In addition, prepaid overhaul balances in FERC Account 186 for Lake Side Units 1 and 2, Chehalis, and Currant Creek gas plants are walked forward to reflect the continued payments and the transfer of these costs into plant in-service through the end of the Test Period. Also, the balance in FERC Account 105, Plant Held for Future Use, related to the acquisition of the Cottonwood coal lease is walked forward to reflect approximately $6.0 million for additional development costs during the Test Period. The Cottonwood coal lease was included as part of Plant Held for Future Use in the 2012 GRC.

Powerdale Hydro Removal (page 8.8) – Powerdale was decommissioned after it was damaged by a flood in November 2006. Deferred accounting for the unrecovered plant balance and decommissioning costs was authorized by the Commission in Dockets No. 07-035-14 and No. 07-035-93. The regulatory assets for unrecovered plant and decommissioning costs were fully amortized by December 2010. This adjustment removes residual items related to the Powerdale hydroelectric plant from results.

Regulatory Asset Amortization (page 8.9) – This adjustment incorporates known and measurable changes to regulatory assets not addressed elsewhere in results. Amortization expense is reflected at the level expected in the Test Period and assets are walked forward to Test Period levels on a 13-month average basis. Assets impacted include: Electric Plant Acquisition Adjustment, Cholla Transaction Costs, Pension Measurement Date Change, and Weatherization Assets. The Utah Independent Evaluator costs turned into a balance owing to customers during the Base Period. This adjustment returns the balance to customers through the Test Period.

Customer Service Deposits (page 8.10) – This adjustment includes customer service deposits in results as a rate base deduction and also includes the interest paid on the customer service deposits in expense. This treatment was stipulated in Docket No. 97-035-01 and has been upheld in subsequent dockets.

Klamath Hydroelectric Settlement Agreement (page 8.11) – This adjustment reflects the appropriate treatment of Klamath related items in the Test Period. Paragraphs 58 through 60 of the 2012 GRC Stipulation address the revenue requirement treatment of various items related to this facility. The stipulation specifies that the Company is permitted to fully depreciate the Klamath dam facilities through 2022 beginning June 1, 2012. This adjustment removes depreciation reserve balances from Test Period results that relate to accelerated Klamath plant depreciation schedules approved by other PacifiCorp state jurisdictions. Adjustment 6.1 includes depreciation expense for Klamath in the Test Period at rates which reflect the 2022 schedule approved in Utah. Adjustment 6.2 reflects the appropriate level of depreciation reserve in the Test Period for Klamath plant.

The 2012 GRC Stipulation also specified that the Klamath-related relicensing and process costs of $81.8 million are included in Utah rates through amortization of the balance through 2022, beginning October 12, 2012, with a carrying charge at the long term cost of debt. Since a carrying charge is reflected in the amortization expense, the relicensing and process cost asset is removed from rate base in this adjustment. This adjustment removes Base Period amortization expense and accumulated reserve associated with the relicensing and process cost asset and includes in Test Period results amortization expense calculated using the methodology prescribed in the 2012 GRC Stipulation. This adjustment also restates Base Period O&M expense for the Klamath facility to levels expected to occur during the Test Period.

Miscellaneous Asset Sales and Removals (page 8.12) – This adjusts the Company's filing for sales or removal of various assets, including the removal of Deseret Power's portion of the Hunter Unit 2 scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, the sale of Snake Creek hydroelectric plant to Heber Light & Power Company, and the sale of St. Anthony hydroelectric plant to St. Anthony Hydro, LLC. A brief description of each item is provided below:

<u>Deseret Power's Portion of Hunter Assets Removal</u> – Removes the capitalized costs pertaining to Deseret Power's ownership share of the Hunter Unit 2 scrubber and turbine upgrade from the Company's filing. The depreciation expense is also removed. A similar adjustment was included in the Company's 2012 GRC filing.

<u>Condit Hydroelectric Asset Decommissioning</u> – Removes electric plant in service, depreciation reserve, depreciation expense, and O&M expense related to the Condit hydroelectric plant from results. A similar adjustment to remove the Condit plant from results was included in the Company's 2012 GRC filing.

<u>Snake Creek Hydroelectric Asset Sale</u> – On September 26, 2011, the Company sold an undivided ownership interest in the Snake Creek hydroelectric generation plant located in Wasatch County, Utah, to Heber Light & Power Company. This adjustment removes residual O&M expense from the Base Period.

There are no corresponding adjustments on electric plant in service, depreciation reserve and depreciation expense as these impacts were recorded outside of the Base Period of this filing. The impacts of this sale were reflected in the Company's filing in the 2012 GRC.

St. Anthony Hydroelectric Generation Plant – On September 30, 2013, the Company sold its St. Anthony facility, a one-unit powerhouse located within the city limits of St. Anthony, Idaho, to St. Anthony Hydro, LLC. This adjustment removes from results the balance in electric plant in-service, depreciation reserve, depreciation expense, and O&M expense related to St. Anthony.

Carbon Plant (page 8.13) – As described in the Company's application in Docket No. 12-035-79, the Carbon plant (a coal-fired generation facility located in Carbon County, Utah) is scheduled to be retired in early 2015 to comply with environmental and air quality regulations. In Docket No. 12-035-79, the Company requested approval to transfer the net book value of the Carbon plant to a regulatory asset once the facility is retired and to amortize the regulatory asset through 2020, the remaining depreciable life of the facility. This matter was addressed in the Company's 2012 general rate case. In that proceeding, stipulating parties agreed to the Company's proposal in Docket No. 12-035-79 to transfer the remaining plant balance at the time of retirement to a regulatory asset and amortization of the balance through 2022. In Docket No. 13-035-02, depreciation rates for Carbon were established effective January 1, 2014, to fully depreciate plant by April 2015.

This adjustment: 1) removes from results the accelerated depreciation expense for the Carbon plant reflected in Adjustment 6.1; 2) adds back to rate base incremental depreciation reserve associated with the Carbon plant accelerated depreciation expense reflected in Adjustment 6.2; 3) includes in rate base the unrecovered plant regulatory asset for Carbon as of April 2015; and 4) adds to the Test Period amortization expense for the unrecovered plant regulatory asset. As addressed earlier in my testimony, the Company is proposing in this case to defer any recovery and amortization of the Carbon removal costs until the next general rate case filing.

Pension and Post Retirement Welfare Plan (page 8.14) – This adjustment adds into rate base the Company's prepaid pension and other post-retirement welfare balance, net of the accumulated deferred income tax liability. This adjustment is supported in the direct testimony of Company witness Mr. Douglas K. Stuver.

Bridger and Naughton Liquidated Damages (page 8.15) – In the 2012 Utah EBA (Docket No. 13-035-32), parties reached a settlement agreement, as approved by the Commission, which credited customers with the benefit of liquidated damages payments received by the Company for outages at Bridger Unit 4 and Naughton Units 1 and 2 through the EBA rather than as a credit to electric plant in service; the liquidated damages payments amount to approximately $1.6 million on a total-Company basis. Parties also agreed that Utah's portion of the liquidated damages payments (set at $700,000 in Docket No. 13-035-32) will be set up as a regulatory asset includable in rate base and amortized over a 20 year period beginning January 1, 2014, to ensure that Utah customers do not receive a double count of the liquidated damages benefit as a credit through the EBA and as a credit to rate base. This adjustment reflects in results the regulatory asset and amortization expense in Test Period results as agreed to in Docket No. 13-035-32.

Q. Are there any other matters that need to be addressed in your direct testimony?

A. Yes, the revenue requirement for this case has been prepared under the assumption that Naughton Unit 3 will cease operations as a base load coal-fired generating unit in December 2014 and be converted to a gas-fired peaking unit by May 2015. As addressed in the testimony of Company witness Mr. Teply, the EPA has a deadline of January 10, 2014, to take final action on the Wyoming Regional Haze State Implementation Plan ("SIP"). The Company has requested that as part of their review of the SIP, the EPA consider extending the operation timeframe of the unit as a coal-fired resource from December 31, 2014 to December 31, 2017.

If the EPA grants the Company's request to extend the operation timeframe of Naughton Unit 3, the Test Period results will be materially impacted. In the event the EPA extends the operation timeframe beyond June 30, 2015, the Company will need to restate the Test Period results to reflect the continuation of the unit as a coal-fired base load generation facility through the Test Period. This includes revisions to net power costs, electric plant in service and accumulated depreciation balances, fuel stock balances, generation O&M expense and related tax impacts. The Company estimates that continuation of Naughton Unit 3 through the Test Period as a coal-fired facility will reduce the

Utah revenue requirement requested in this case by $5.2 million. If the EPA allows continuation of the unit as a coal-fired facility beyond the Test Period, the Company will update the revenue requirement request in this case as part of its rebuttal filing.

Q. Do you have any final comments regarding the revenue requirement requested by the Company in this proceeding?

A. Yes, in my opinion, the revenue requirement requested in this proceeding is fair, reasonable and in the public interest. The Test Period results developed as described previously in my testimony are a reasonable projection of costs the Company expects to occur during this period in order to provide electric service to customers in the state of Utah.

Q. Does this conclude your direct testimony?

A. Yes.