Rocky Mountain Power
Docket No. 13-035-184
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Steven R. McDougal

Revenue Requirement

June 2014

Q. Are you the same Steven R. McDougal who submitted direct testimony in this proceeding on behalf of PacifiCorp dba Rocky Mountain Power (“the Company”)?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to and rebut certain issues raised by Division of Public Utilities (“DPU”) witnesses Dr. Artie Powell, Mr. Matthew Croft, Mr. Robert Davis, Mr. Richard Hahn, Mr. Clair Oman, Mr. Eric Orton, and Mr. David Thomson; Utah Office of Consumer Services (“OCS”) witness Ms. Donna Ramas; Utah Association of Energy Users Intervention Group (“UAE”) witness Mr. Kevin Higgins; Utah Industrial Energy Consumer (“UIEC”) witness Mr. Jonathan A. Lesser; and Federal Executive Agencies (“FEA”) witness Mr. Greg Meyer.

First, I present a revised calculation of the Company’s revised Utah-allocated revenue requirement and revenue increase requested in this case. The Company’s revised revenue requirement includes adjustments made to its original filing that address certain corrections identified by the Company and items raised in the direct testimony of intervening parties. Next, I discuss the Company’s opposition to certain adjustments proposed by intervening parties that are not incorporated into the revised revenue requirement presented herein. Last, I discuss the Company's proposal pertaining to the Naughton unit 3 gas conversion.

Revised Revenue Requirement

Q. Have you recalculated a revised revenue requirement for the Test Period?

A. Yes. The Company has adopted a number of adjustments reflecting updates and corrections to its original filing and issues identified by intervening parties through their direct testimony in this case, reducing the overall requested price change from $76,252,101 to $66,429,236. A summary of the Company's revised revenue requirement is provided in Exhibit RMP___(SRM-1R) and details of the revenue requirement calculation, including new adjustments to the revenue requirement, are included in Exhibit RMP___(SRM-2R). The revised results of operations for the twelve months ending June 31, 2015, (the "Test Period") demonstrate that under current rates, the Company will earn an overall return on equity ("ROE") of 8.7 percent in Utah.

Q. Please describe how Exhibit RMP___(SRM-2R) is organized.

A. Exhibit RMP___(SRM-2R) is the Company's revised Utah results of operations report (the "Report") incorporating all adjustments to the revenue requirement identified in my rebuttal testimony. The Report is organized into sections marked with tabs in a similar manner as Exhibit RMP___(SRM-3). Tabs 1, 2 and 11 of Exhibit RMP___(SRM-2R) replace tabs of the same number in Exhibit RMP___(SRM-3) previously filed by the Company in this proceeding. Tab 12 of Exhibit RMP___(SRM-2R) is a new section of the Report that identifies all adjustments made by the Company in its rebuttal case to the original filing and provides details supporting the calculation of the adjustments. All adjustments in Tab 12 are incremental to the revenue requirement submitted in the Company's original filing.

Q. Please summarize the adjustments the Company is incorporating into its revised revenue requirement calculation.

A. As shown in Table 1, the Company is making the following adjustments to the revenue requirement originally proposed in this proceeding related to corrections identified by the Company and issues addressed in the direct testimony of intervening parties:

Table 1 ($millions)

Filed Price Change		**$ 76.252**
Adjustment Name	**Adj No.**	**Amount**
Capital Structure and Cost Update		(3.514)
Net Power Cost Update	12.1	(4.948)
Fuel Stock Update	12.2	(0.024)
Wages and Benefits Update	12.3	(0.419)
REC Revenue	12.4	(0.427)
REC Revenue 10 Percent Incentive	12.5	0.245
Special Contract Revenues	12.6	(0.269)
Sub-lease Revenue	12.7	0.083
Lease Expense	12.8	(0.208)
Challenge Grants	12.9	(0.048)
Uncollectible Accounts Expense	12.10	(0.292)
Condit Hydroelectric Dam Decommissioning Expense Correction	12.11	0.949
Lobbying Expenses	12.12	(0.000)
Reduction to Affiliate Charges	12.13	(0.432)
Cottonwood Coal Lease	12.14	(0.027)
Bridger and Trapper Update	12.15	0.087
Lake Side 2 Prepaid Overhaul	12.16	(0.300)
Jim Bridger Unit 3 Small Projects	12.17	(0.044)
FC200 to FC300 Replacement	12.18	(0.035)
Mill Fork South Lease Acquisition	12.19	(0.076)
Vehicle Replacement	12.20	(0.002)
DPU Updates Adjustment	12.21	1.405
Big Fork Penstock	12.22	(0.004)
Casper Outer Loop	12.23	(0.006)
U3 OH Boiler Waterwall Tube Replacement At Naughton	12.24	(0.024)
Soda Spillway Improvements Project	12.25	(0.051)
Depreciation Expense Update	12.26	0.921
Depreciation Reserve Update	12.27	(2.134)
Tax Impacts Update	12.28	(0.033)
Renewable Energy Tax Credit Update	12.29	(0.000)
Contingency Reserve	12.30	(0.195)
Total Adjustments		(9.823)
Rebuttal Price Change		**$ 66.429**

<u>Adjustments to Revenue Requirement</u>

Q. Please explain the updates, corrections or other revisions the Company has incorporated into its rebuttal case.

A. Subsequent to filing the original revenue requirement request in this proceeding, the Company identified certain items to be updated in net power costs, miscellaneous fuel stock, wages and benefits, hydro decommissioning expense, and the renewable energy tax credit. Additionally, the Company has adopted several adjustments proposed by parties in this proceeding. The majority of these items have been communicated to intervening parties through discovery and addressed in their direct testimony. I address individually the adjustments made by the Company in developing its rebuttal revenue requirement.

Capital Structure

Q. Were any changes to capital structure included in your revised revenue requirement?

A. My rebuttal exhibit includes the impacts of the revised capital structure as supported in the rebuttal testimony of Mr. Bruce N. Williams. These updates result in a decrease of $3,513,858 to the Company's original request.

12.1 Net Power Cost Update

Q. Please explain the adjustment to update Net Power Costs.

A. Page 12.1 of Exhibit RMP___(SRM-2R) updates the net power costs included in the case consistent with the April 10, 2014, net power cost update ("NPC Update") filing submitted by the Company in this proceeding and as addressed by Company witness Mr. Gregory N. Duvall in his rebuttal testimony. As a result of the NPC Update, Test Period net power costs are reduced from $1,521.9 million to $1,510.2 million on a total Company basis, and from $641.1 million to $636.1 million on a Utah-allocated basis. The NPC Update decreases the revenue requirement requested in this case by $4,947,729.

12.2 Fuel Stock Update

Q. Did the NPC Update affect any other aspects of revenue requirement in this case that are not reflected in the 12.1 Net Power Cost Update adjustment?

A. Yes. The NPC Update included changes to the Company's coal costs that impact the Company's coal fuel stock balances by plant for the Test Period, shown on Exhibit RMP___(SRM-3), page 8.7.1. The updates to the NPC result in a $217,160 decrease in the Company's fuel stock levels in the Test Period. This information was also provided in the Company's response to data request OCS 29.1. This adjustment is shown in Page 12.2 of Exhibit RMP___(SRM-2R). The NPC Update also impacts the Renewable Energy Tax credits, which is discussed later in my testimony.

12.3 Wages and Benefits Update

Q. Please summarize the contents of the revised Wages and Benefits adjustment.

A. Page 12.3 of Exhibit RMP___(SRM-2R) contains an updated Wages and Benefits adjustment which reduces the Company's request by $417,851 on a Utah-allocated basis. Included in this adjustment are various changes due to updates identified by the Company or adjustments proposed by the intervening parties that the Company accepted. Table 2 summarizes the changes included in the updated Wages and Benefits adjustment:

Table 2 - Wage and Benefit Adjustment Summary

	UT Allocated Amount
Medicare Tax Correction Adjustment	$ (1,289)
Wage Increase Incremental Adjustment	1,115
AIP Incremental Adjustment	102,501
Pension Update Incremental Adjustment	(213,717)
Postretirement Update Incremental Adjustment	(122,869)
Normalize 401k Incremental Adjustment	(74,533)
Eliminate Severance Incremental Adjustment	(109,060)
Total Rebuttal Adjustment	$ (417,851)

Each of these items is briefly described below:

Medicare Tax Correction

On November 26, 2013, the Internal Revenue Service implemented the Additional Medicare Tax as added by the Affordable Care Act ("ACA"). The Additional Medicare Tax applies to compensation over certain thresholds and is paid for by the employee at 2.35 percent. The Company's initial filing incorrectly applied the Additional Medicare Tax rate to the employer portion of Medicare tax, resulting in the pro forma payroll tax being overstated by $1,289.

Wage Increases

In February 2014, the Company finalized labor contract negotiations with IBEW 57 Combustion Turbine ("CT"). The Wage and Benefits adjustment updates the wage increase showing in Exhibit RMP___(SRM-3) on Page 4.2.5 to the final contractual amounts. The increase previously shown in February 2014 as 1.25 percent in Exhibit RMP___(SRM-3) has been moved to March 2014 and increased to 1.65 percent. In addition, the IBEW 57 CT increase in Feb 2015 has been decreased from 2.75 percent to 2.0 percent. These changes result in an incremental increase to Utah-allocated utility labor by $1,115.

Annual Incentive Plan

This adjustment updates the filing for the actual calendar year 2013 Annual Incentive Plan (“AIP”) payouts. The actual amount is now known and has been reflected in the Company's updated adjustment. This effectively increases labor expense on Utah-allocated utility labor by $102,501.

Pension Expense

This adjustment updates the Test Period pension expense to reflect an updated actuarial report provided by Towers Watson to the Company for the Calendar year 2014. The impact of this adjustment reduces the Company’s pension expense in the rebuttal filing by $213,717 and is consistent with the adjustment that was proposed in the direct testimony of Mr. Higgins. However, the Company has a concern that this type of adjustment is generally only made when the projections decrease. The Company respectfully requests that the Commission require the update as a policy in future cases, regardless of the direction of the update. Ms. Ramas also proposed an adjustment to the Company’s pension expense that the Company did not accept. Reasons for the rejection of Ms. Ramas’ adjustment are discussed later in my testimony.

Post-retirement Benefit Expense

This adjustment updates the Test Period level post-retirement benefits expense to reflect the impact of the Company’s revised calendar year 2014 plan expense. This adjustment reduces the Company’s expense in the rebuttal filing by $122,869, and is also consistent with the adjustment proposed in the direct testimony of Mr. Higgins.

401(k) Administration Costs

Ms. Ramas stated that 401k administrative costs were abnormally high during the 12 months ended June 30, 2013 (the "Base Period"), proposing to normalize these costs over a three-year period to reduce volatility caused by credits from the 401(k) plan administrator coming through intermittently. This adjustment normalizes Test Period 401(k) administration costs to reflect a typical level as recommended by Ms. Ramas, resulting in a reduction of labor expense by $74,553 on a Utah-allocated basis.

Severance Expense

Severance expense was removed from the Base Period as recommended by Ms. Ramas, decreasing the Test Period labor expense by $109,060. The Company agrees to remove severance expense from the case, but reserves the option to include severance expense in future filings.

12.4 REC Revenuue

Q. Does Exhibit RMP___(SRM-1R) include an adjustment to revenue associated with sales of the Company's Renewable Energy Credits ("REC")?

A. Yes. The Company provided an updated REC revenue forecast in its 1st Supplemental response to data request UAE 2.2. The updated REC revenue forecast contained additional known REC sales volumes and prices. The Company incorporated the updated REC revenue forecast in the rebuttal case, consistent with the recommendations of Ms. Ramas, Mr. Davis and Mr. Higgins. This update decreases the revenue requirement by $427,155.

12.5 REC Revenue 10 Percent Incentive

Q. Please explain the 10 percent incentive adjustment associated with REC revenues in this case.

A. The Stipulation in Docket No. 11-035-200 ("2012 Stipulation") specified that the Company would be allowed to retain 10 percent of the revenues obtained from sales of RECs incremental to the forecast REC revenue included in that case of $25 million through May 31, 2013, and thereafter incremental to the revenues received under contracts entered into after July 1, 2012 included in Confidential Exhibit B to the 2012 Stipulation. The Company did not account for the 10 percent incentive in the original filing with the intention of including it in the RBA filing. Ms. Ramas and Mr. Davis point out that accounting for the 10 percent incentive in the general rate cases sets the amount of REC revenue included in base rates at a more accurate level, avoiding carrying charges on this amount. Therefore, the Company revised the REC revenue adjustment in this case to account for the 10 percent incentive. The Company calculated the incentive by taking 10 percent of the Utah allocated REC revenue during the Test Period, i.e., $2,449,852, which produces a $244,985 decrease in Utah-allocated REC revenues.

12.6 Special Contract Revenues

Q. Please summarize the adjustment proposed by Mr. Higgins related to Special Contract Revenues.

A. Mr. Higgins recommends that the Company adjust revenues in this case for Special Contract 1, which is subject to a 1.93 percent base rate increase on

January 1, 2015, per the terms of the contract. Mr. Higgins states that the 1.93 percent change needs to be applied to the Special Contract 1 pro forma revenue estimated by the Company to properly reflect Test Period level revenues. Mr. Higgins' adjustment adds $268,722 in revenue, calculated as approximately half of the annualized January 1, 2015 increase based on the proportion of kilowatt-hours projected for Special Contract 1 for the period January through June 2015, relative to total Test Period kilowatt-hours for this customer as forecast by the Company.

Q. Did the Company revise the Test Period revenues to incorporate the additional revenue from the Special Contract 1 increase as recommended by Mr. Higgins?

A. Yes, the Company incorporated Mr. Higgins' recommended adjustment, adding $268,722 of revenues to the Test Period. Details of this adjustment are contained on page 12.6 of Exhibit RMP___(SRM-2R).

12.7 Sub-lease Revenue and 12.8 Lease Expense

Q. Did any intervening party propose an adjustment with respect to the Company's sub-lease revenues and lease expense?

A. Yes. Mr. Davis proposed the removal of expired sub-lease revenues and lease expenses from the Test Period. His adjustment removed $196,080, or $83,276 Utah-allocated, of sub-lease rental income associated with the Wilsonville capital lease. Mr. Davis also recommends the removal of total-Company lease expense associated with the 1033 Building lease in the amount of $256,574, the Wilsonville lease in the amount of $227,736 and the Keystone Aviation Hanger lease for $4,250. The Wilsonville Distribution Center lease and the 1033 Building lease expired before the beginning of the Test Period and the need for space in both cases was absorbed elsewhere with no additional expense. In addition, 14 monthly payments for the Keystone Aviation Hangar were inadvertently included in the Base Period.

Q. Does the Company agree with the proposed adjustment to sub-lease revenue and lease expense?

A. Yes, the Company finds Mr. Davis' adjustment to be reasonable as these items do not reflect ongoing revenues or expenses. This adjustment is located on pages 12.7 and 12.8 of Exhibit RMP___(SRM-2R).

Q. Did the Company find any small corrections to Mr. Davis' adjustment calculation?

A. Yes. Mr. Davis removed the two months of Keystone Aviation Hangar expense on a System Overhead ("SO") factor, but the expense was recorded in unadjusted results on a System Generation ("SG") factor. The Company correctly uses the SG allocation factor in its rebuttal adjustment.

12.9 Challenge Grants

Q. Please describe the adjustment proposed by Mr. Orton with regards to challenge grants.

A. Mr. Orton removes challenge grants booked by the Company during the Base Period.

Q. Does the Company agree to remove challenge grants as proposed by Mr. Orton in this case?

A. Yes. The Company has included an adjustment to remove the challenge grants from the filing as shown on page 12.9 of Exhibit RMP___(SRM-2R). This reduces the Company's O&M expense by $48,103.

Q. Why does this amount differ from the $158,750 amount removed by Mr. Orton in his direct testimony?

A. During the Base Period, the Company booked a total of $158,750 associated with challenge grants. However, the Company directly assigns these amounts to the individual states, and Mr. Orton incorrectly included the total Company amount and not the Utah amount in his adjustment. Only $48,103 of the $158,750 total was assigned to Utah. Therefore, the Company revised the amount of challenge grants removed to accurately reflect the amount included in the original filing.

12.10 Uncollectible Accounts Expense

Q. Please describe the adjustment proposed to the Company's uncollectible accounts expense.

A. On August 2, 2013, the Commission approved an update to Electric Service Regulation No. 3 resulting in the direct assignment of Collection Agency fees to individual delinquent accounts. Due to this change, the Company agreed in its response to data request OCS 4.12 to adjust the uncollectible expense in rebuttal. Mr. Thomson, Ms. Ramas and Mr. Higgins propose an adjustment to the Company's uncollectible expense in the amount of $449,965, representing the $434,331 for costs associated with collection fees escalated for inflation.

Q. Does the Company agree that an adjustment is warranted to uncollectible expense?

A. Yes. However, the full amount of the uncollectible expense savings will not be realized during the Test Period. Table 3 below shows the projected fee savings by calendar year. Because the assignment of collection agency fees to delinquent accounts only applies to new arrearages, the Company does not expect to fully eliminate collection agency fees until 2017.

Table 3

Year	Projected Fee Savings
2014	$234,103
2015	$358,680
2016	$387,106
2017	$401,738
Total	**$1,381,627**

Therefore the Company's rebuttal filing includes an adjustment on page 12.10 of Exhibit RMP___(SRM-2R) in the amount of $291,521, calculated as the average of calendar year 2014 and 2015 savings escalated for inflation.

12.11 Condit Hydroelectric Dam Decommissioning Expense Correction

Q. Please describe the adjustment the Company made to correct the original filing related to the Company's Miscellaneous Asset Sales and Removals adjustment in your direct testimony Exhibit RMP___(SRM-3) on Page 8.12.

A. In the Company's original filing, the plant balances and associated expenses related to the Condit dam were removed in the Miscellaneous Asset Sales and Removals adjustment since the plant is no longer in service. As part of the adjustment, the Company inadvertently removed $2,224,227 in depreciation expense that was not associated with the Condit dam. Upon review, this expense represents the accrual of the hydro decommissioning for several of the Company's hydro plants and should not have been removed. The hydro decommissioning detail can be found in RMP___(SRM-3) on page 6.3.9. Page 6.3.9 shows the west side Base Period accruals total of $2,224,227, the amount incorrectly removed as part of the Condit plant adjustment on page 8.12. Since the hydro decommissioning costs are an expense related to assets providing service to customers, the Company has made an adjustment to correct the Condit dam removal adjustment. This correction increases Utah's depreciation expense by $948,151. Supporting detail for this adjustment can be found on page 12.11 of Exhibit RMP___(SRM-2R).

12.12 Lobbying Expenses

Q. Please describe the adjustment Mr. Orton makes with respect to lobbying expenses incurred by the Company.

A. Mr. Orton suggests that the portion of membership dues paid by the Company to Edison Electric Institute ("EEI") and United Telecom Council ("UTC") that relates to lobbying efforts be removed from the revenue requirement. He recommends an adjustment to decrease the revenue requirement by $89,337.

Q. Does the Company agree with Mr. Orton that lobbying expenses should be excluded in customer rates?

A. Yes. The Company agrees that expenses incurred for lobbying activities should not be included in rates to be recovered from customers. However, the majority of the adjustment proposed by Mr. Orton was for costs that were not included in the rate case. The Company removed $295 in lobbying expenses from the revenue requirement requested in this case.

Q. Please describe why the Company's adjustment for lobbying expense is less than that proposed by Mr. Orton.

A. The amount of UTC dues the Company paid in the Base Period was $13,348. The percentage of the expenses attributable to lobbying activities was five percent. Since all of the UTC dues the Company paid in the Base Period were booked above-the-line, five percent was removed in this adjustment, which is $295 on a Utah-allocated basis.

Q. Does the Company agree with Mr. Orton's adjustment to reduce EEI dues expense in the Test Period by $209,658?

A. No. The lobbying expenses associated with EEI were booked below-the-line and are not included in the Company's filing. Since Mr. Orton's adjustment is removing an expense that is not included in the original filing, the EEI portion of his adjustment is erroneous and should be rejected.

12.13 Reduction to Affiliate Charges

Q. Please describe the adjustment proposed by Ms. Ramas related to the recent NV Energy acquisition.

A. Due to the recent acquisition of NV Energy, Inc., certain charges associated with MidAmerican Energy Holding Company, now "Berkshire Hathaway Energy," and MidAmerican Energy Company that were previously allocated to PacifiCorp will now be allocated to NV Energy as shown in Ms. Ramas' exhibit OCS 3.9D. This reduces the costs charged to PacifiCorp by an estimated $1,014,774 on a total-Company basis. Ms. Ramas recommends adjusting the Company's revenue requirement accordingly.

Q. Does the Company agree that an adjustment is necessary for this item?

A. Yes. It is appropriate to reflect the impact of the transaction. The Company incorporated Ms. Ramas' adjustment as shown on page 12.13 of my rebuttal exhibit.

12.14 Cottonwood Coal Lease

Q. Please summarize the Cottonwood Coal Lease adjustment proposed by Mr. Davis.

A. The Company provided revised actual development costs for the year ended 2013 for the Cottonwood Coal Lease in its response to data request DPU 16.1. Correspondingly, RMP___(SRM-3), page 8.7.1 was updated with the revised July 2013 through December 2013 development cost numbers and ensuing adjustments through 2014, which resulted in a downward adjustment to Test Period results in Plant Held for Future Use of $596,835 on a total Company basis, and $250,502 on a Utah-allocated basis.

Q. Does the Company accept Mr. Davis' Cottonwood Coal Lease adjustment?

A. Yes. Mr. Davis' adjustment utilizes the most up-to-date costs for the Cottonwood Coal Lease. This adjustment reduces the revenue requirement by $27,140.

12.15 Bridger/Trapper Update

Q. Please explain Mr. Croft's adjustment to Bridger Mine and Trapper Mine rate base.

A. Mr. Croft proposes to update the Bridger Mine and Trapper Mine rate base balances and the Trapper mine final reclamation liability balance with actual data through March 2014, replacing projected data through this period used in the original filing.

Q. Does the Company agree with this adjustment?

A. Yes. The Company has reflected this adjustment in determining the revised results of operations for the Test Period. This adjustment increases the revenue requirement by $86,899, and is detailed on page 12.15 in Exhibit RMP___(SRM-2R).

12.16 Lake Side 2 Prepaid Overhaul

Q. Please explain the correction to Lake Side 2 prepaid overhaul capital costs recommended by Ms. Ramas and Mr. Croft.

A. Ms. Ramas and Mr. Croft correctly point out in each of their testimony that the Company includes overhaul prepayments in rate base as part of the miscellaneous rate base adjustment. These are pre-paid amounts associated with overhaul costs that are ultimately capitalized as plant-in-service when the overhaul is completed. The Miscellaneous Rate Base adjustment on page 8.7 of Exhibit RMP___(SRM-3) included the projected average Test Period prepayments for the Lake Side U11 and U12 combustion overhaul. The associated capital costs were included in plant-in-service with an in-service date of March 2015 in the Company's Pro

Forma Plant Additions and Retirements adjustment on Page 8.6.23 of Exhibit RMP___(SRM-3). In reviewing the details, Ms. Ramas and Mr. Croft noted that there is a two month period during which the capital costs were included in both the prepayments and in plant-in-service and suggest that the Company reduce the plant-in-service along with the depreciation expense and accumulated depreciation to correct this.

Q. Does the Company agree with this adjustment?

A. Yes, with a few minor corrections. In its response to data request OCS 19.11, the Company agreed that the capital costs associated with Lake Side U11 and U12 Combustion Overhaul projects should reflect an in-service date of May 2015. However, the Company's calculation correctly compares depreciation expense between the March 2015 in-service date depreciation and the May 2015 in-service date depreciation to arrive at the appropriate amount. Depreciation expense was $280,689 using the March 2015 in-service date and $120,295 using the May 2015 in-service date. The Company adjusted the depreciation expense by $160,394, representing the total Company difference between the two in-service dates. The Company utilized the same method in calculating the adjustment to depreciation reserve. Depreciation reserve was $49,352 based on a 13-month average using the March 2015 in-service date, and $12,338 based on a 13-month average using the May 2015 in-service date on a total Company basis. The Company adjusted the depreciation reserve by $37,014, which represents the difference between the two in-service dates. This correction to the capital database will reduce pro forma rate base by $5,037,792, pro forma depreciation expense by $160,394, and pro forma depreciation reserve by $37,014 on a total Company basis. This equates to a reduction in rate base of $2,147,526 and a decrease in Depreciation Expense of $68,373 on a Utah jurisdictional basis. The overall impact of this adjustment decreases the revenue requirement by $299,620 and is detailed on page 12.16 of my rebuttal exhibit.

Q. Did Mr. Croft raise additional concerns regarding the Lake Side 2 Overhaul Project Costs?

A. Yes. In his direct testimony, Mr. Croft states that the Company provided two schedules showing the budgeted prepayment dollars for the Lake Side 2 plant. The schedules show how dollars are built up in this account and then transferred to plant-in-service. In addition to the correction addressed above, Mr. Croft also states that the amount being transferred to capital based on the overhaul schedule is only $28,044,166, while the capital database shows $32,745,646 being placed in service for the same project. Therefore, in addition to correcting for the two-month overlap, Mr. Croft also proposes that the Company reduce the amount of capital transferred from prepayments to capital.

Q. Does the Company agree with Mr. Croft's additional adjustment to Lake Side 2 Overhaul amounts?

A. No. Mr. Croft erroneously assumed that the full cost of the overhaul was reflected in the prepaid account, which is wrong. The capital database value of $32,745,646 includes the total amount of the capital project that is expected to be placed in service at the time of the overhaul. The $28,044,166 reflects the prepaid balance only. When the capital project is placed in service it will include other items such as an outage service fee, capital surcharge and Allowance for Funds Used During Construction ("AFUDC"). The actual amount that will be placed into service is $32,745,646 and should not be reduced as recommended by Mr. Croft in this case.

12.17 Jim Bridger Unit 3 small projects

Q. Please explain Mr. Croft's adjustment to Jim Bridger Unit 3 small projects.

A. Through discovery, the Company provided its capital database that reflected 46 small projects under $1 million associated with the Jim Bridger Unit 3 overhaul that were scheduled to occur during the months of May and June of 2015. Because the overhaul has been delayed to November 2015, which is outside the Test Period, Mr. Croft proposes the removal of these projects.

Q. Does the Company agree with the adjustment?

A. Yes, the Company agrees to remove these items from the rate case. This adjustment reduces Utah's revenue requirement by $43,600 and can be found on page 12.17 of my rebuttal exhibit.

12.18 through 12.25 Various Capital Adjustments

Q. Please describe the various capital adjustments the Company made in its rebuttal filing in response to the requests by the intervening parties.

A. Mr. Hahn and Mr. Croft recommended numerous adjustments to the Company's capital projects in each of their direct testimony. The Company carefully reviewed the testimony and exhibits filed by Mr. Hahn and Mr. Croft to determine the validity of their recommendations. This section of my testimony summarizes the adjustments recommended by Mr. Hahn and Mr. Croft which the Company considers to be valid. Later in my testimony, I present the Company's response to the recommended adjustments that I disagree with and have not incorporated into the rebuttal case.

12.18 FC200 to FC300 Replacement

This adjustment revises the revenue requirement to correctly reflect Utah's portion of the FC200 to FC300 replacement project at $279,160 as proposed by Mr. Hahn. The impact on the case reduces the revenue requirement by $34,782, including a correction for a minor formula error found in Mr. Hahn's depreciation expense calculation. Page 12.18 of my rebuttal exhibit contains the details of this adjustment.

12.19 Mill Fork South Lease Acquisition

This adjustment removes the Mill Fork South Lease from the projected plant-in-service, which was proposed by Mr. Hahn. The impact on the case reduces revenue requirement by $76,098, and is shown on page 12.19 of my rebuttal exhibit.

12.20 Vehicle Replacement

This adjustment removes the Vehicle Replacement project from the projected plant-in-service, as proposed by Mr. Hahn. The impact of this adjustment reduces revenue requirement by $2,018 and is included in my rebuttal exhibit on page 12.20.

12.21 DPU Updates Adjustment

Mr. Croft sponsors the DPU Updates adjustment, which replaces the forecast major capital additions data in the Company's original filing with actual data for the months of July 2013 through February 2014. The adjustment also updates for changes to the forecast provided by the Company in its response to data request DPU 35.4. Changes to the Company's major plant additions forecast include the removal of projects that have been canceled or delayed past the Test Period, changes to in-service dates and the addition of projects that were not included the original filing but are now expected to be placed in service during the Test Period. This adjustment includes the removal of condemnation settlement payments as proposed by Ms. Ramas. The impact of these updates is shown on page 12.21 of my rebuttal exhibit. Collectively, these updates increase the Company's revenue requirement by $1,404,545. The depreciation expense, depreciation reserve and deferred tax impacts are accounted for in adjustments 12.25, 12.26 and 12.27.

<u>12.22 Big Fork Penstock</u>

This adjustment removes the Big Fork Penstock project from the projected plant-in-service, which was proposed by Mr. Hahn. This adjustment reduces revenue requirement by $3,666 and is included in my rebuttal exhibit on page 12.22.

<u>12.23 Casper Outer Loop</u>

This adjustment revises the Casper Outer Loop project as discussed by Company witness Mr. Douglas N. Bennion in his rebuttal testimony. Mr. Bennion discusses the reasons why the Company is revising the Casper Outer Loop project amounts instead of accepting Mr. Hahn's recommendation to remove it entirely from the Test Period. The impact of this adjustment reduces revenue requirement by $6,346 and is included in my rebuttal exhibit on page 12.23.

12.24 U3 OH Boiler Waterwall Tube Replacement at Naughton

This adjustment revises the U3 OH Boiler Waterwall Tube Replacement at Naughton project as proposed by Mr. Hahn. The impact of this adjustment reduces revenue requirement by $24,260, and is included in my rebuttal exhibit on page 12.24.

12.25 Soda Spillway Improvement Project

This adjustment removes the Soda Spillway Improvement project because the in-service date has moved outside the Test Period. The impact of this adjustment reduces revenue requirement by $51,206, and is included in my rebuttal exhibit on page 12.25.

12.26 Depreciation Expense and 12.27 Depreciation Reserve Updates

Q. Please describe the Depreciation Expense and Depreciation Reserve Update adjustments included in your rebuttal exhibit.

A. The Company updated the depreciation expense and reserve amounts to account for the impacts of the DPU updates adjustment on page 12.22 described above. The update to depreciation expense results in a revenue requirement increase of $920,576 as provided in my rebuttal exhibit on page 12.26. The correlating adjustment to the depreciation reserve balance decreases the revenue requirement by $2,134,179 and is shown on page 12.27.

12.28 Tax Impacts Update

Q. Please describe the tax impacts update adjustment.

A. This adjustment updates deferred taxes for the changes made to the capital included in the rebuttal filing.

12.29 Renewable Energy Tax Credit Update

Q. Why did the Company include an update to the Renewable Energy Tax Credits?

A. The renewable energy tax credit adjustment that was included in the Company's original filing, Exhibit RMP___(SRM-3), page 7.3, was updated in the rebuttal case to be consistent with the NPC Update. The NPC Update reduces the renewable energy tax credit amount included in the Test Period by $202. Details are provided in my rebuttal exhibit on page 12.29.

12.30 Contingency Reserve

Q. Please explain the adjustment to contingency reserves as proposed by Mr. Higgins.

A. Mr. Higgins proposes to update project contingency reserves provided in this case to reflect updated contingency amounts provided in the Company's response to data request UAE 11.1. The update produces a $3.6 million downward adjustment from $11.8 million to $8.2 million, reducing the revenue requirement by $195,247.

Q. Does the Company agree with this adjustment?

A. Yes. Mr. Higgins adjusts the contingency reserves to a more recent and accurate amount and is incorporated into the Company's rebuttal revenue requirement as shown on page 12.30 of my rebuttal exhibit.

Q. Does the Company's acceptance of Mr. Higgins' proposed adjustment resolve all of Mr. Higgins' concerns related to contingency reserves?

A. No. Mr. Higgins raised additional issues with the principle of using contingency reserves. The rebuttal testimony of Company witness Mr. Chad A. Teply addresses Mr. Higgins' ratemaking policy concerns.

Condemnation Settlements

Q. Please describe the condemnation settlement adjustment proposed by Ms. Ramas.

A. Ms. Ramas proposes removing condemnation settlements associated with the Populus-Terminal 345 kV line.

Q. What is the Company's position with respect to the adjustments to remove condemnation settlement costs as proposed by Ms. Ramas?

A. The Company accepts Ms. Ramas' adjustment related to the condemnation settlements regarding the Populus-Terminal 345 kV line. This adjustment was also included in the DPU updates, and has therefore been removed as part of adjustment 12.21, DPU Updates Adjustment.

Carbon Non-Labor O&M Expense

Q. Please describe the proposed adjustments to the non-labor O&M expense associated with the Company's Carbon plant.

A. The Company's original filing included approximately $4,472,000 in non-labor O&M expense associated with the Carbon plant. Since the Carbon plant is scheduled to be retired in April 2015, both Ms. Ramas and Mr. Higgins claim that leaving this expense in the case will cause the expense to continue to be included in rates beyond the point in time when Carbon is providing service. Ms. Ramas and Mr. Higgins agree that the Company should be able to recover the non-labor O&M expenses for the Carbon plant until it is removed from service and suggest that a mechanism be put in place which allows the Company to recover the costs, but prevents customers from continuing to pay these costs after the plant is retired.

Q. Please respond to Ms. Ramas' and Mr. Higgins' proposal.

A. The Company agrees in principle with Ms. Ramas' and Mr. Higgins' observation that if these costs are recovered in base rates, they will continue to be charged to customers after the Carbon plant is retired and they are no longer being incurred, until superseded by rates established in a subsequent rate case.

Q. How could this be remedied?

A. As noted by Mr. Higgins, the Test Period Carbon O&M expense could be moved from base rates to a rider that would expire after 12 months. Another option would be to convert the Test Period expenses into a regulatory asset and recover them over a specified period of time similar to the Carbon-specific deferred accounting treatment currently being used to recover plant removal costs and the remaining depreciation balance. The Company prefers the method proposed by Ms. Ramas. The amount in rates resulting from Carbon O&M expense could be recorded as an offset in the Carbon Removal Cost regulatory asset each month. This monthly offset to the regulatory asset would continue until the rates established in the next general rate case go into effect.

Q. Does the Company agree with Ms. Ramas' adjustment?

A. In principle, yes. However, the $4.4 million represents the amount that the Company needs to recover related to the nine months the plant will be in service during the Test Period. Based on the Test Period, this amount will be recovered over a twelve month period (The $4.4 million is included as an annual amount in the revenue requirement). Therefore, in order to allow the Company the opportunity to recover the $4.4 million related to Test Period expenses, the Company must include the Carbon costs in rates for twelve months.

<u>Analysis and Response to Adjustments not Included in the Company's Case</u>

Annual Incentive Plan

Q. Please explain the adjustment to the Company's AIP proposed by Mr. Oman and Mr. Meyer.

A. Mr. Oman adjusts the calendar year 2013 AIP payout percentage to the average of the calendar year 2009 through 2012 payout percentages. Mr. Meyer proposes a 33 percent reduction in AIP.

Q. Does the Company agree with either of these proposed adjustments?

A. No. There is no basis for Mr. Oman's indiscriminate adjustment. The Company paid out the AIP at 100 percent in 2013. The AIP program has been established to put a portion of employees' total compensation at risk, making it dependent on employee performance. To reduce the percentage paid out in 2013 simply because it is different from the prior years is inappropriate because the Company already used a three-year average to calculate AIP in the original filing to effectively smooth out differences from year to year. Proposing a downward adjustment on the highest value in a set of data, changes the methodology from an average, as approved in prior Utah general rate cases, to using the lowest percentage payout. Mr. Oman gives no justification for this change in methodology, and provides no evidence that moving away from an average is appropriate.

Mr. Meyer’s adjustment to reduce the AIP percentage is based on nothing more specific than his general criticism of the program, with no support for his percentage disallowance. The Company requested Mr. Meyer provide support for the 33 percent reduction in data request RMP 2.1. When asked for the basis of the 33 percent, Mr. Meyer’s response was “The 33 percent disallowance is a *subjective* [emphasis added] estimate of the portion of the AIP payments which relate to the financial goals, lobbying and/or tasks which should be considered normal job requirements.” Mr. Meyer’s 33 percent reduction is arbitrary and should be rejected by the Commission. Further support for the Company’s AIP is provided in the rebuttal testimony of Mr. Erich D. Wilson.

Net Pension and Post-Retirement Welfare Plan Prepaid Asset

Q. Please summarize the proposed adjustment related to the Company’s net pension and post-retirement welfare plan prepaid asset.

A. Dr. Powell, Ms. Ramas and Mr. Higgins disagree with the Company’s position that the net pension and post-retirement welfare plan prepaid asset should be included in rate base. They propose to reverse the Company’s adjustment shown on page 8.14 of Exhibit RMP___(SRM-3), which produces a decrease in revenue requirement of approximately $7.0 to $7.5 million

Q. Does the Company agree with this adjustment?

A. No. The Company maintains that this net pension and post-retirement welfare plan prepaid asset should receive rate base treatment. Company witness Mr. Douglas K. Stuver provides support for the inclusion of this asset in rate base.

Unclassified Plant (FERC Accounts 106 and 1019)

Q. Please explain Mr. Croft's adjustment to Unclassified Plant (FERC Account 106).

A. Mr. Croft proposes removing the full amount of the June 2013 balance for unclassified plant because he believes the unclassified plant balances are already accounted for in FERC accounts 301 to 399. On lines 160-162 of his testimony, Mr. Croft defines FERC 106 as "plant that has been placed into service and is providing benefits to customers but has not technically been classified yet to the appropriate plant account (Accounts 301 to 399)."

Q. Is the assertion by Mr. Croft that there is a double count of unclassified account balance in the JAM accurate?

A. No. This is an erroneous assumption. Mr. Croft simply does not understand how the Pro Forma Capital Additions adjustment works. The Pro Forma Capital Additions and Retirements adjustment is calculated by taking the June 2015 13-month average balance and subtracting the June 2013 13-month average balance. The amount included in the JAM model is correct.

Q. Has the Company included FERC 106 in prior cases?

A. Yes. The Company has included FERC 106 in all prior rate cases, using both historic and forecast test periods, in all states. The Company is unaware of anyone challenging the inclusion of FERC 106 because the unclassified plant is property that is already in service, and is appropriately included in the case.

Q. Is Mr. Croft's Table 3 showing the flow of unclassified plant correct?

A. No, the flow is correct. However, the numbers in Mr. Croft's table are wrong.

Q. What evidence exists to ensure there is no double counting of unclassified plant in the Company's filing and that Mr. Croft's table is wrong?

A. There is a reconciliation included with the Pro Forma Capital Additions and Retirements adjustment in Exhibit RMP___(SRM-3), page 8.6.2 that ties the total electric plant in service ("EPIS") from adjustment 8.6 Pro Forma Capital Additions and Retirements to the "EPIS balance in the JAM, as seen in Exhibit RMP___(SRM-3), page 2.2, line 36. This reconciliation is included to show that all forecasted EPIS dollars are accounted for and tie to the JAM. This reconciliation shows the $25,515,027,180 on Mr. Croft's table, and how it reconciles to the EPIS total on pages 2.2 and 2.30 Exhibit RMP___(SRM-3). It is important to remember that unclassified plant is a part of EPIS.

Q. Is the $87 million unclassified plant referenced in Mr. Croft's table included in the rate case?

A. Yes. However, it is already included as part of the $25.15 billion amount in Mr. Croft's Table 3, and should not be included a second time as he is showing in his table. As can be seen on the reconciliation included with the Pro Forma Capital Additions and Retirements adjustment in Exhibit RMP___(SRM-3), page 8.6.2, the only differences between the $25.15 billion on the pro forma plant addition sheet and the total EPIS in the case are mining assets, Little Mountain and an Oregon solar project. This reconciliation was provided to avoid questions similar to the one raised by Mr. Croft. If a double count did exist, this reconciliation would not tie to the JAM.

Q. Does the Company agree with Mr. Croft's assertion that the FERC 106 balances are included in the FERC 301 - 399 plant accounts as stated on lines 148-150, 210, and 216-218?

A. No. Mr. Croft is wrong. FERC 106 is not included in the FERC 301 - 399 plant accounts and is also not included in plant additions because the FERC 106 balances are already in-service. The plant is specifically referred to as unclassified because it is has not been classified to the 301 - 399 FERC accounts yet.

Q. Did Mr. Croft describe how he came to the conclusion that unclassified plant balances should be removed?

A. According to his direct testimony, Mr. Croft arrived at this conclusion through examination of three key questions: 1) What capital assets are going into service? 2) When are they going into service? and 3) Does the Company's capital database, depreciation template and JAM accounts 301 to 399 already account for when these asset go into service and when they are depreciated?

Q. Does the Company agree with Mr. Croft that those are the appropriate questions to ask?

A. Yes. Mr. Croft asked the right questions. The problem is that he did not list the correct answers, resulting in an incorrect conclusion.

Q. Can you please describe where Mr. Croft erred in his answers to these questions?

A. Mr. Croft erred in his response to the third question. The FERC 106 balances are part of EPIS. They are included in the beginning balance, and not as part of future plant additions, because they are already in service. By removing these amounts, Mr. Croft is removing plant that is already in service.

Q. What is unclassified plant?

A. Unclassified plant is plant which has been placed into service but for which the final cost analysis to determine which specific FERC accounts to which it should be charged has not yet been completed. Unclassified plant is a part of EPIS. Usage of unclassified plant is approved by FERC. The level of detail for unclassified plant is at the plant function level i.e., steam, hydro, distribution.

Q. What adjustments incorporate the unclassified plant balance?

A. The Depreciation and Amortization Expense, Depreciation and Amortization Reserve adjustments, and Pro Forma Plant Additions and Retirements incorporate unclassified plant. The June 2013 actual unclassified plant is included to more accurately calculate the depreciation expense and depreciation reserve. The plant balances are adjusted each month for forecasted plant additions, retirements and removals. There is no additional forecasted unclassified plant additions included.

Q. Has the Company reviewed the FERC 1019 adjustment, proposed by Mr. Croft?

A. Yes.

Q. Are there any computational or methodological errors in the adjustment?

A. Yes. FERC account 1019 was already removed in the DPU’s unclassified plant adjustment. An additional adjustment to remove FERC 1019 balances would result in a double count.

Q. Please explain how this results in a double count.

A. The $87 million removed in the unclassified plant adjustment included the FERC

1019 balance. Therefore, the 1019 adjustment is duplicative.

Q. What is FERC account 1019 used for?

A. At the end of each quarter, the Company estimates the amount of unprocessed retirements to ensure the asset account balances are accurate.

Miscellaneous General Expense - Civic Memberships

Q. Please describe Mr. Orton's proposed adjustment to remove expenses for Civic Memberships.

A. Mr. Orton proposes to remove from the Test Period expenses associated with dues paid by the Company to chamber of commerce organizations. He asserts that the Company's participation in these organizations does not provide a direct, quantifiable benefit to customers, and is not necessary to the Company's efforts of providing safe and reliable electric service to customers.

Q. Does the Company agree with Mr. Orton's assessment?

A. No. Contrary to Mr. Orton's perspective, Company participation in these organizations does provide tangible benefits to customers. The Company is linked to the economic viability of the communities it serves and to the actions taken by community leaders with respect to Company operations. A primary purpose of membership in these organizations is to foster and strengthen relationships with key civic and business leaders in the community. Positive working relationships help streamline Company efforts in making necessary investments to provide safe and reliable electric service to customers.

As an example, the Company is a member of the Utah Valley Chamber of Commerce and is supporting the chamber in economic development activities for siting new business expansion. By participating in this initiative, Rocky Mountain Power can aid in identifying more favorable sites where electrical service is more readily available than less desirable sites. By being part of the process, the Company is able to provide better service to customers at potentially lower costs.

Participation also allows the Company to develop and build relationships within the community. This helps employees to speak on a regular basis and be available for members of these organizations, who are also Rocky Mountain Power customers, to discuss issues of concern such as service, billing or programs, so that the employee can quickly and more easily resolve these issues without undue disturbance to the customer. Many of these organization members are key customers and run businesses that are major employers in the community. These relationships are invaluable for employees to understand business needs and concerns, and respond appropriately.

Another example of the benefit of membership in these organizations is with the Salt Lake Chamber of Commerce. The Company has served on various committees within the chamber which has helped to educate and inform members of the chamber on key issues facing the Company such as new investments in the power system to plan for reliable service and new customer growth and enlist their support for programs to help customers use energy more efficiently.

Mr. Orton provides little demonstrable evidence to support his claim that these costs provide no quantifiable benefit to customers, or that regulatory bodies in other jurisdictions have excluded these types of costs from rate recovery. For these reasons, the Company recommends that the Commission not adopt Mr.

Orton's proposed adjustment to chamber of commerce dues.

Demand Side Management, Blue Sky and Project Silver Expenses

Q. Please explain the adjustment to Demand Side Management, the Blue Sky program, and Project Silver as proposed by Mr. Orton.

A. Mr. Orton proposes to remove Demand Side Management and Blue Sky costs charged to FERC account 921 as they are recovered under separate surcharges. Mr. Orton also proposes to remove any Project Silver costs charged to FERC account 921 on the grounds that they relate to the Nevada Energy acquisition and should have been recorded below-the-line.

Q. Are there any computational errors made by Mr. Orton in his adjustment?

A. Yes. Mr. Orton's adjustment considers only one side of the entry for Demand Side Management, Blue Sky, and Project Silver expenses charged to FERC account 921. When the expenses were charged to FERC account 921, an offsetting entry was then recorded during the same period to settle the expense to a below-the-line account. The result is a net-zero charge to FERC account 921 for Demand Side Management, Blue Sky, and Project Silver expenses.

Q. Does the Company agree with the adjustment to Demand Side Management, Blue Sky and Project Silver as proposed by Mr. Orton?

A. No. As noted above, this is a one-sided adjustment and singles out only debit entries. The charges only flow through FERC account 921 and are eventually settled into the correct order number in the same period. Accepting Mr. Orton's adjustment would effectively remove costs from the revenue requirement that were never included in the case in the first place.

Pension Expense/Post-retirement Benefit Expense

Q. Earlier in your testimony you accepted Mr. Higgins' proposed adjustment to pension and post-retirement benefit expense but rejected the adjustment proposed by Ms. Ramas. How does Ms. Ramas' adjustment differ from the one proposed by Mr. Higgins?

A. Mr. Higgins uses the method utilized by the Company in this proceeding. He substitutes the updated 2014 forecast number for the earlier one used in the filing. Ms. Ramas however, takes the difference between the updated 2014 forecast and the original 2014 forecast used in the filing. This is flawed logic because the filing is based on the Test Period, 12 months ending June 2015. Since the actuarial reports cover calendar years, the Company based its forecast on a 50/50 split of 2014 and 2015. Ms. Ramas treats the forecast pension expense as if the Company were using 12 months ending December 2014 as the Test Period. On line 277 of her testimony, Ms. Ramas gives the reason for this treatment as:

> "Absent RMP providing updated estimates of the 2015 net periodic benefit costs from its actuarial firm as requested in OCS Data Request 3.16, I recommend that Test Year pension costs be reduced by the reduction in the projected 2014 net periodic benefit costs."

This is not valid and should be rejected by the Commission. 2015 estimates of the net periodic benefit costs were not available. To then assume the difference between the amount originally filed and the updated amount is somehow equivalent to the 2014 difference is unfounded. In actuarial projections, each year can be very different. Pension expenses for 2015 are already considerably lower than 2014, so it would be invalid to assume the estimate would decrease by the same dollar amount.

The Company accepts Mr. Higgins' adjustment because it correctly implements the methodology utilized by the Company to update expense forecasts, as stated above. The Company rejects the interpretation offered by Ms. Ramas.

Legal Expenses

Q. Please describe the legal expense adjustment proposed by Mr. Higgins, Ms. Ramas and Mr. Thomson.

A. Mr. Higgins proposes removing from the case legal costs related to the USA Power and Deseret Power disputes. Ms. Ramas proposes removing legal expenses related to the USA Power dispute. Mr. Thomson also proposes to normalize legal costs related to the Wood Hollow fire by escalating and amortizing them over five years.

Q. What is the Company's position with respect to the adjustments to remove legal costs as proposed by Mr. Higgins, Ms. Ramas and Mr. Thomson?

A. The Company opposes these adjustments. The level of legal costs included in the case are the level the Company anticipates in the future.

Q. Why is it appropriate for the Company to include legal costs escalated to the test period?

A. These costs are ordinary and typical business costs necessary for any business to operate effectively. The Company has no control over the type of lawsuits that are filed against it, just as it has no control over a jury verdict. The Company will continue to incur legal costs necessary to defend itself from third parties or power plant joint-owners in the future, regardless of whether the lawsuits have any merit and whether a jury verdict goes against the Company.

Simply stated, the Company will always incur legal expenses to deal with a variety of issues. Not one of Mr. Higgins, Ms. Ramas, nor Mr. Thomson points to anything that suggests the Company will have fewer legal expenses on a going-forward basis. In fact, Table 4 below summarizes legal expenses for the last four years. The results show the 12 months ended June 2015 legal costs forecast included in the filing is comparable to prior years, is almost the exact amount of the four-year average, and is at a reasonable ongoing level, particularly when considering the ongoing litigation.

Table 4

Period	External Legal Expense (1)
CY 2010	15,191,707
CY 2011	17,608,560
CY 2012	14,174,477
CY 2013	16,884,101
4 year average	15,964,711
Base Period	15,226,268
Test Period	15,964,534

Notes:
(1) Above the line only, stated in 2013 dollars

Q. Please describe the Legal Consulting Costs adjustment proposed by Mr. Thomson in regard to the Wood Hollow fire.

A. Mr. Thomson's adjustment attempts to normalize and amortize over five years legal consulting service expense related to the Wood Hollow fire due to what he perceives to be an abnormal level of one-time occurring costs in the Base Period.

Q. Does the Company agree with the Legal Consulting Costs adjustment proposed by Mr. Thomson?

A. No. Mr. Thomson's proposed adjustment should likewise be rejected because the table above clearly shows that the legal costs as projected for the 12 months ended June 2015 are in line with the Company's four year average, in fact, they are almost identical amounts. If the legal costs related to the Wood Hollow fire were abnormal, keeping them as a Base Period expense would produce abnormally high projected legal costs, and that is clearly not the case here.

Carbon Overhaul Expense

Q. Please explain Carbon Overhaul Expense adjustment as proposed by Ms. Ramas and Mr. Higgins respectively.

A. In its original filing, the Company normalized generation overhaul expense using a four-year average methodology. The Carbon plant generation overhaul expense was scaled back by 25 percent, representing April to June 2015, in the four-year average totals due to the plant's scheduled April 2015 retirement. Ms. Ramas and Mr. Higgins propose to remove 100 percent of the Carbon plant generation overhaul expense from the Test Period calculation, resulting in a decrease of $633,903 on a total Company basis and $270,222 on a Utah basis before escalation. Mr. Higgins' adjustment also incorporates escalation of past generation expense.

Q. Does the Company agree with the proposed Carbon Overhaul adjustments?

A. No. To be consistent, averaging adjustments need to be made over the entire span of the four years. During the years in which the Company performs plant overhauls, the expense is reduced to an average, which may include years with no overhauls. Eliminating Carbon plant from the four year average used during the Test Period doesn't allow the expense to be increased consistent with the earlier decrease. For example, if an overhaul costs $1,000, the Company would only recover $250 during that year because only one-quarter of the cost is to be recovered each year. If a plant were retired before the end of the four years included in the average, the Company would not recover the full $1,000 unless it was permitted to continue to include the plant's $1,000 in the four-year average until the end of the four years. The Carbon Plant Overhaul adjustment does not afford the Company the opportunity to recover the $2,703,000 cost of the 2013 overhaul at Carbon as shown on page 4.8.2 of RMP___(SRM-3), which has not been included in any prior cases. As in the example discussed above, the four-year average methodology results in only 25 percent of the cost of the Carbon Overhaul being included in the Company's filed case. Removing the entire cost of the overhaul increases the under recovery of this expense.

Q. Ms. Ramas argues that this adjustment is fair because the Company also includes projected overhauls for new generation plants like Lake Side 2. How does the Company respond to this argument?

A. The Company did not begin an averaging methodology for generation overhauls until the 2008 general rate case, in Docket No. 07-035-93. Therefore, the Company would not have added a projected amount as is the case with Lake Side 2. Because of this error in methodology, the Company urges the Commission to reject Ms. Ramas' and Mr. Higgins' adjustments.

Plant Additions

Q. Please describe the adjustment entitled "Late Additions to Capital Projects Database," proposed by Mr. Hahn.

A. In DPU 35.4, Mr. Hahn requested that the Company provide capital projects that were not in the original July 2013 to June 2015 forecast that are now expected to be placed into service during the March 2014 to June 2015 time period, within the Test Period. The Company provided 10 specific projects that fit the criteria in its response, which are listed in Mr. Hahn's Exhibit DPU 3.5 Dir-Rev Req. These projects were included in the DPU Update adjustment proposed by Mr. Croft. Mr. Hahn deemed the projects to be unsupported and proposes removing them from the case.

Q. Does the Company accept this adjustment?

A. No, with the exception of the Naughton U3 OH Boiler Waterwall Replacement and the Soda Spill Way Gate projects, which were removed from the case as described earlier in my testimony as adjustments 12.24 and 12.25.

Q. Please list the capital projects discussed in this adjustment?

A. The eight projects that were not included in the Company's original filing but were provided to the DPU through discovery and included in the DPU's plant additions update adjustment are listed below, along with the Company witness who provides support for the project in rebuttal testimony:

1. Wallowa Falls, *Mr. Mark Tallman*
2. Swift Side Nets, *Mr. Mark Tallman*

3. Swift Main Net, *Mr. Mark Tallman*
4. Yale Upper Rock Block, *Mr. Mark Tallman*
5. DJ U3 Primary Superheater Mid Span, *Mr. Dana Ralston*
6. Lakeside U12 Combustion Turbine Exhaust Cylinder, *Mr. Dana Ralston*
7. Huntington U1 FGD Inlet Duct Header, *Mr. Dana Ralston*
8. Vantage Pomona Heights, *Ms. Natalie Hocken*

Chehalis CSA Variable Fee

Q. Please explain Mr. Croft's adjustment to the Chehalis CSA Variable Fee.

A. Based on the Company's response to data request OCS 4.33, Mr. Croft proposes a reduction in costs for this project from the $29,676,287 shown in the capital database to the $25,742,236 prepaid balance, referenced in the data request. This cost reduction results in a $15,241 decrease in Utah's revenue requirement.

Q. Does the Company agree with this adjustment?

A. No. The referenced capital database value of $29,676,287 includes the total amount of the capital project that is expected to go in-service at the time of the overhaul. The $25,742,236 reflects only the prepaid balance, derived from the variable factor fired hour fees paid. When the capital project is placed in-service it will include items such as outage service fees, capital surcharge and AFUDC. Therefore, the recommended adjustment should be rejected.

Employee Reductions

Q. Please describe the adjustment proposed by Ms. Ramas concerning employee reductions.

A. Ms. Ramas proposes an adjustment based on her assertion that employee headcount in the Company's filing is not reflective of the likely Test Period level. Her adjustment reduces revenue requirement by approximately $3,685,197.

Q. Does the Company accept Ms. Ramas' adjustment?

A. No. Mr. Wilson provides support for the level of employees included in the Company's original filing.

Wage and Benefit Expense

Q. Does the Company agree with the adjustment proposed by Mr. Higgins reducing revenue requirement for the difference in the number of employees at January 2014 compared to June 2013?

A. No. As addressed in the testimony of Mr. Wilson, the labor costs included in this case are at an appropriate level and reflect the level necessary for the Company to provide safe and reliable service to our customers.

Generation Overhaul Expense

Q. Please explain Ms. Ramas' adjustment to Generation Overhaul Expense.

A. Ms. Ramas proposes to reduce revenue requirement on a total Company basis by $1.5 million, and $625,426 on a Utah-allocated basis. This proposed reduction removes the adjustment applied by the Company to restate the prior year overhaul expenses to a June 2013 level before calculating the four-year average level of overhaul costs.

Q. Is the Company's position that generation overhaul expense must be restated to current dollars supported by any intervening parties in this case?

A. Yes. In his direct testimony, Dr. Powell provides a detailed and astute argument supporting the Company's methodology on this issue in this case. On lines 115-

116 referring to the Company's generation overhaul expenses ("GOE") he says, “failure to account for inflation will systematically underestimate or understate the Company’s test period GOE.” Dr. Powell then goes on to introduce new evidence to support his claims using economic theory that lead to the conclusion stated on lines 155-159:

> "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."

Q. Does the Company agree with Dr. Powell’s conclusion as it relates to the generation overhaul adjustment?

A. Yes. Before averaging historical amounts from different years, it is important that the dollars be correctly stated using constant dollars. Since dollars from different years have different purchasing power, failing to restate each of these dollar levels to a common basis is analogous to comparing apples to oranges to bananas. To ignore an adjustment accounting for the differing purchasing power of dollars in different years is to ignore inflation has occurred. Any financial analysis performed by the Company in evaluating investment alternatives by necessity and common sense must consider inflation. Ms. Ramas states that productivity offsets and lessons learned will offset any inflationary drivers. This simplistic assumption is a notion that would be difficult to support by actual data.

Q. As pointed out by Ms. Ramas, the Commission has ruled against the use of escalation to constant dollars in prior cases. Why does the Company think the Commission should reconsider its position?

A. Based on the arguments provided both in my testimony and that of DPU witness Dr. Powell in this case, the Company urges the Commission to reconsider its position on this issue.

Q. Please explain Mr. Higgins' adjustment to Generation Overhaul Expense.

A. Mr. Higgins proposes to reduce Company revenue requirement on a total Company basis by $378,000, and $161,000 on a Utah-allocated basis. This proposed decrease represents a reduction to the forecasted overhaul cost included for the Lake Side 2 plant. This reduction is derived from a ratio which Mr. Higgins calculates based on actual overhaul expenses versus projected overhaul expenses applied for in rates. Based on the Company's past general rate case filings, Mr. Higgins asserts that the Company had overestimated projected overhaul costs by 62.7 percent on average for the Currant Creek and Lake Side 1 plants over the period 2007 through 2011. Thus, in the current case, he states that generation overhaul expense must be scaled back by this proportion to more accurately reflect the actual expense to be expected for this project.

Q. Does the Company agree with Mr. Higgins' generation overhaul adjustment?

A. No. Mr. Higgins argument is based on a generalization. In reality, the appropriateness of the amounts included in the rate case should be based on the reasonableness of the amount included. As supported in the rebuttal testimony of Mr. Ralston, the forecasted overhaul expense for Lake Side 2 is reasonable, and the Company urges the Commission to reject the Generation Overhaul adjustment as proposed by Mr. Higgins. As summarized in table 5 below, Mr. Higgins table KCH-3 shows actual average overhaul costs for the first four years of operations for the Currant Creek and Lake Side 1 plants at $1.7 million and $1.2 million, respectively. By comparison, the Company is including only $1.0 million for the four year average of Lake Side 2 in Exhibit RMP___(SRM-3) page 4.8.2, less than either Currant Creek or Lake Side 1. Therefore, his overhaul adjustment should be rejected.

Table 5

Plant	4 Year Average Overhaul Cost	Source
Currant Creek	$1,685,095	Table KCH-3
Lake Side 1	$1,237,744	Table KCH-3
Average	$1,461,420	
Lake Side 2	$1,031,295	Exhibit RMP___(SRM-3) Page 4.8.2

Construction Work In-Progress ("CWIP")

Q. What issue does Ms. Ramas raise with the inclusion of CWIP in the current case?

A. Ms. Ramas proposes to remove the amounts associated with the Wallula McNary project and Generation Compliance Initiative Hardware. Ms. Ramas explains that the Wallula McNary project currently being charged to an expense account in order to establish a reserve in the event of a possible write-off, poses risks of double recovery if the Company determined a need and completed the project. Ms. Ramas also recommends removing the write-off of unused electronic equipment associated with the Generation Compliance Initiative Hardware security project, which was done to comply with NERC/Critical Infrastructure Protection Standards ("NERC CIPS").

Q. Please elaborate on the details of the Wallula McNary 230Kv line project in dispute.

A. The Oregon Public Utilities Commission ("OPUC") issued a Certificate of Public Convenience and Necessity ("CPCN") in September 2011. In 2013, the project was delayed based on customer needs. Based on this delay, the Company continues to evaluate the need for the project. In anticipation of a possible write off, the Company has established a reserve account for $1.7 million.

Ms. Ramas argues if the project is deemed necessary and placed into service the Company will double-recover the cost. She recommends removing the amount charged to expense to establish the reserve from the Test Period for this proceeding. To avoid a double recovery, the Company would offset the cost as described below if the project continues.

Q. What is the Company's proposed treatment of the write-off reserve for Wallula McNary if the project is completed?

A. Currently, the Wallula McNary line includes a $1.7 million CWIP reserve account established for the possibility of a write-off. In the event the construction of the line was completed, the reserve would be reversed and the project would move from CWIP to plant-in-service. Since this reserve is proposed to be collected from customers, a reserve balance would be credited to plant-in-service for the same CWIP reserve amount upon completion. The overall result would fully offset the

CWIP reserve account to customers. The project is currently being monitored by the Company to ensure the accuracy of future accounting methods if this situation does arise.

Q. Please elaborate on the details of the Generation Compliance Initiative Hardware in dispute.

A. In 2008, following an assessment of the extensive nature of the NERC CIPS standards, the Company made the decision to hire an outside consultant to design a fully integrated compliance program that would bring its critical asset generation facilities and operations into compliance with the new NERC CIPS standards. The "Matrikon" solution that was chosen included a complete set of compliant policies, procedures, and documentation, as well as a network design that allowed each critical asset generation facility to automate many of its compliance obligations, while simultaneously meeting the new cyber security requirements imposed by the new NERC standards.

In February of 2010, PacifiCorp Energy management and the PacifiCorp IT department performed an internal reassessment of the Matrikon solution. The assessment concluded that while the Matrikon solution provided a compliant program, it also presented several undesirable drawbacks, among which were: (1) requiring the Company to rely on a third-party vendor for its compliance program; (2) requiring that the Company either add internal headcount or hire Matrikon on an ongoing basis in order to sustain the compliance program; (3) essentially requiring the creation of an IT department within the Generation organization; and (4) reinforcing the stand-alone operation mode of the critical asset generation plants rather than moving closer to a centralized, integrated solution.

The IT department presented the Company with an alternative compliance model that was instead primarily supported by internal resources. The alternative compliance model offered the benefit of centralizing many of the compliance tasks that, under the Matrikon solution, would have been performed independently by plant personnel at each of the critical asset facilities.

When this option was deemed more viable, the determination was made to terminate the original Matrikon scope of work and to pursue implementation of the alternative compliance model proposed by the IT department. The work is now being done by the in-house IT group with the changes in scope reflecting fewer facilities requiring the full-scale implementation. Ms. Ramas proposes to remove this project on the basis that the Company did not complete a robust analysis of the project and the costs could have been avoided by using internal resources rather than an outside vendor.

Q. Does the Company agree with Ms. Ramas' assessment?

A. No. The Company maintains that at the time the decisions were made to incur the costs related to these projects, these solutions were thought to be the best available to the Company to solve these specific issues. In coming to this conclusion, the Company underwent its own process of due diligence into all of the available solutions using the best, most complete information it could gather at the time. However, additional information revealed during the implementation process of these solutions, uncovered and unforeseen potential safety concerns and other undesirable consequences of which the Company was not previously aware. Subsequent reassessments of these projects given the new information indicated that alternative solutions would be better suited to meet the Company's needs. Though the Company could not perfectly foresee all of the consequences of these projects prior to making the decision to begin their implementation, this is a basic reality of operating any business. Any decision the Company makes can only be based on the best information it can obtain at the time. These decisions are constantly reassessed pursuant to new information that becomes available so that the Company can serve its customers in the most efficient way possible. The Company is opposed to the idea of prohibiting specific CWIP write-off expenses related to projects that were canceled.

Q. Does the Company accept Ms. Ramas' proposed adjustment to CWIP?

A. No. The Company has established accounting protocols and internal resources to ensure that any projects with reserve accounts will be properly accounted for and not double-recovered from customers. Additionally, the Generation Compliance Initiative Hardware solution was thought to be the best available to the Company to solve these specific issues at the time and are normal operating costs of doing business. The investments made for such compliance purposes should not be excluded from rates.

O&M Expense Escalation

Q. Please explain the adjustment to the escalation of non-labor O&M costs proposed by Mr. Higgins.

A. Mr. Higgins' proposed adjustment removes the increases to non-labor O&M expense through the application of IHS Global Insight Inc. ("IHS") escalation factors as projected for the Test Period. He cites two primary concerns: (1) including a provision for escalation in rates makes inflation a “self-fulfilling prophecy”; and (2) including escalation in the Company’s rates builds a “cost cushion” and provides a disincentive for the Company to improve efficiency. His adjustment reduces the Company’s revenue requirement by $2.4 million.

Q. Has the Commission ruled favorably on the use of escalation rates?

A. Yes. In Docket No. 07-035-93 the Commission stated, “In this case, we find use of Global Insight inflation forecasts is appropriate and provide the Company adequate incentive to manage their non-labor O&M costs (other than net power costs).”

Q. Why does the Company oppose Mr. Higgins’ adjustment?

A. Mr. Higgins’ position that including a forecast of inflation in the Company’s case becomes a self-fulfilling prophecy is overreaching. The proposed adjustment is based solely on his interpretation of high-level, macro-economic indicators and not empirical evidence of the cost pressures facing the utility industry and the Company. The Company is simply reflecting the cost of goods and services that it projects to experience during the Test Period. If these cost increases are not reflected in the Company’s projected revenue requirement, it will impact the Company’s ability to recover the costs necessary to serve customers during the rate-effective period.

Q. Does the Company agree that including escalation serves as a “cost cushion” for the Company?

A. No. Planning for the costs the Company will incur in providing service to customers during the Test Period is not a cost cushion, but rather an accepted practice in setting rates that will allow the Company an opportunity to recover its prudently incurred costs as needed to provide safe and reliable electrical service. Mr. Higgins purports that the use of a test period through mid-2015 is "aggressively-forward", and that "RMP should not be rewarded for the use of an aggressively-forward test period with a windfall-markup of costs…" (Ref Line 285). In fact, the Test Period for the current rate case was specifically selected to align closely with the rate-effective period. This is the period when the Company is to provide services to customers, and in doing so, this is also the period when the Company will be making the O&M expenditures. It is evident, then, that O&M expenses should rightfully be matched to the real economic dollars of the rates paid by customers. To reject any adjustment to O&M for inflationary pressures would mean that rates will continue to be set based on expenses at 2013 levels, while the Company's actual expenses are incurred at 2015 levels. This will result in chronic under-earning and does not afford the Company a reasonable opportunity to earn its authorized return and counters the objective of ameliorating regulatory lag.

Q. Does escalation of O&M expense create a disincentive to O&M efficiency efforts?

A. No. In fact, the Company has managed costs and drastically improved O&M efficiencies in spite of the inclusion of an O&M expense escalation adjustment in past cases. The Company agreed to a stayout period in the last case, and has managed costs to try and minimize customer rate impacts, and will continue to manage costs, but inflationary pressures are inevitable and out of the Company's control.

Q. Has Mr. Higgins proposed a similar adjustment in past general rate cases?

A. Yes. Mr. Higgins has proposed the complete removal of inflation from the Company's cases since 2007. Had Mr. Higgins been successful in persuading the Commission to remove escalation from the Company's case, today the Company's expenses would be chronically lagging actual costs, preventing the Company from recovering the costs of serving customers. Adequate planning for these costs is vital to the Company's ability to provide electric service, and ignoring inflation in planning, rate cases, retirements, or any other activity would be irresponsible.

Q. What additional arguments does Mr. Higgins provide to support his adjustment?

A. Mr. Higgins claims that inflationary pressures will not be substantial through the Test Period. He lists two sources to support this claim: the Minutes of the Federal Reserve Open Market Committee from March 18-19, 2014, and the February 2014 forecast of the Congressional Budget Office. Both of these sources contain high level discussions of national economic factors, including core inflation, which is anticipated to be in the range of 1.4 percent to 1.6 percent in 2014 and 1.7 percent to 2.0 percent in 2015. Both of these indicate that inflation will exist, and should not be ignored.

Q. Why does the Company believe that the IHS Global Insight escalation factors included in the case are more appropriate than Mr. Higgins' core inflation argument?

A. IHS conducts thorough research that is highly specialized to the electric utility industry. Based on its research, IHS formulates escalation factors related to specific FERC accounts. In contrast, core inflation is a broad predictor of inflation that is measured based on aggregate price growth excluding food and energy prices. While core inflation can be a valuable tool when examining the economy as a whole, it is too broad to be an accurate predictor of the specific cost pressures the Company will experience during the Test Period.

Incremental Generation O&M

Q. Please explain Ms. Ramas' adjustment to Incremental O&M costs.

A. Ms. Ramas proposes to reduce the Company's Incremental O&M adjustment by $14.3 million on a total Company basis or $6.1 million on a Utah-allocated basis. She recommends increasing the O&M expense for the Test Period to escalated amounts (escalation factors are provided by IHS) only, rather than the Company's forecasted Test Period amounts. On line 937 of her testimony she does, however, make an exception for the Carbon, Lake Side 1, Lake Side 2, and Naughton plants which she accepts on the basis they are "unique and significant circumstances."

Q. Are there any additional adjustments Ms. Ramas has proposed to Incremental O&M costs?

A. Yes. As requested in OCS 19.4, a billing delay true-up for Cholla occurred during the months of May and June of 2013 for $1,656,330. Ms. Ramas proposes to adjust Cholla actuals for this billing delay which caused Cholla to be understated by $1.6 million.

Q. Does the Company agree with the adjustment as proposed by Ms. Ramas?

A. No, the Company does not agree given the upward trend in costs necessary to operate and maintain the Company's thermal generation resources. These increases include environmental cost increases, non-reagent chemical increases, and additional maintenance increases. Additional pertinent details are provided in the rebuttal testimony of Company witness Mr. Ralston.

In regards to the billing true-up proposed by Ms. Ramas, the Company also rejects this adjustment on the premise that the mathematical result is a net zero. Ms. Ramas proposes to reduce the incremental O&M adjustment for the Cholla billing delay by $1,656,330. However, Ms. Ramas does not provide a separate adjustment which would be required to increase the base by the equivalent amount. To accurately address the billing delay, two adjustments would be required: an adjustment to increase the base period by the billing delay amount to correctly state the base and test period costs, then an adjustment to decrease incremental O&M adjustment. The overall result of the two adjustments would completely offset one another. If a decision were made to adopt the methodology of Ms. Ramas, the Company would also need to provide an offsetting adjustment to the base period. Ms. Ramas is attempting to adjust from a corrected base amount, without actually correcting the base amount.

Bonuses and Awards

Q. Please explain Mr. Meyer's adjustment to bonuses and awards.

A. Mr. Meyer asserts that bonuses and awards given to employees were administered with no set criteria or plan documentation. He proposes to completely remove these amounts from the filing.

Q. Does the Company agree with this adjustment prohibiting all bonuses and awards excluding AIP amounts?

A. No. As fully supported in the rebuttal testimony of Company witness Mr. Wilson, these bonuses and awards serve to attract, retain, and justly recognize employees of the Company who meet and exceed personal and Company-wide goals.

Residential Revenue and Load Adjustment

Q. Please explain Mr. Meyer's adjustment to Residential Revenue and Load.

A. Mr. Meyer believes the Company has overstated the reduction in forecasted loads for residential revenues. Mr. Meyer attempts to make an adjustment related to loads, but appears to lack the understanding that any change in load changes three revenue requirement components: 1) revenues; 2) net power costs; and 3) allocation factors.

Q. Are there any computational or methodological errors in Mr. Meyer's adjustment?

A. Yes. Mr. Meyer's testimony has four areas where over-simplification has caused errors. The first is in the load adjustment itself, which is addressed in the testimony of Company witness Ms. Kelcey A. Brown. His second error is in the calculation of revenues, where an average rate was used without looking at the impact on specific rate schedules and rate tiers. The third error is in the simplifying assumptions regarding net power costs. Mr. Meyer adjusts net power costs assuming 39 percent of revenues, as opposed to looking at the impact that the load would have on incremental power costs. The last error is that Mr. Meyer fails entirely to account for how a change in load will impact allocation factors. Any change in load will change the energy and peak loads used to allocate costs to Utah, including the SG, System Energy ("SE"), and SO allocation factors. A change in these factors would have a cascading effect on multiple issues, particularly the allocation of O&M, A&G, capital, generation and transmission rate base, and deferred taxes, all of which would shift costs to Utah. Because of these errors and simplifications this adjustment should be rejected.

Naughton and Medicare Tax Amortization

Q. Does the Company agree with the adjustment proposed by Mr. Meyer prohibiting amortization of the Naughton U3 Emission Cost Regulatory Asset and the amortization of the regulatory asset associated with the tax impact of healthcare reform changes to the deductibility of Medicare retiree drug subsidies?

A. No. This adjustment has already been accounted for in the Company's filed case. Mr. Meyer's adjustment constitutes a double count. Concerning the Naughton regulatory asset, in my direct testimony filed for this case, lines 267-276 stated:

> "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, the 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."

Since adjustment 4.10 in Exhibit RMP___(SRM-3) already completely removes this cost, Mr. Meyer's proposed adjustment to remove it a second time would be double counting and therefore should be rejected.

Q. Why would adjusting the Medicare Tax regulatory asset constitute a double count?

A. Again referring to my direct testimony, lines 739 - 743 state:

> "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. Nonutility 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."

The non-recurring Medicare Tax regulatory asset was removed from the filing in adjustments 7.6 and 7.7. Again, Mr. Meyer is proposing to remove a cost that does not exist in the case.

Fixed Costs Associated with Lower Energy Sales

Q. Please summarize Mr. Lesser's testimony regarding fixed costs associated with lower energy sales.

A. Mr. Lesser contends that the Company should not be afforded the guarantee to recover their fixed costs due to lower energy sales, and the risk should be borne by the shareholders should the Company be unable to recover fixed costs through wholesale market sales.

Q. What are the fallacies in Mr. Lesser’s argument?

A. The Company is not seeking a guarantee for fixed cost recovery. The 2010 Protocol dictates the methodology by which costs are allocated among the states, and has been applied correctly in this proceeding. Mr. Lesser's argument has no merit, and has no specific recommendation or remedy. The Company will respond to the rate design part of Mr. Lesser's testimony in the cost of service phase of this case.

Retail Transmission at FERC OATT

Q. Please explain Mr. Lesser’s proposed adjustment with regards to the transmission costs paid by retail customers.

A. Mr. Lesser states that the Company should charge all customers the same transmission costs. He argues that retail customers should incur the same FERC Open Access Transmission Tariff (“OATT”) rate that wholesale customers are charged. He also believes that other costs that the Company includes in its retail transmission rates, such as purchases of transmission services from other companies, should be functionalized as generation-related costs, thus making all customers equal, paying the same FERC OATT rate.

Q. Does the Company agree with Mr. Lesser’s proposed adjustment to transmission rates charged to retail customers?

A. No. This is an issue that is addressed by the allocation methodology utilized by the Company. The 2010 Protocol allocation methodology has been agreed upon by all parties to be used through December 31, 2016. This is not an issue that Mr. Lesser should be arguing in this general rate case, and the adjustment should not have been recommended. The issue has been previously discussed in Multi-State Process (“MSP”) negotiations, and an agreement was made by all parties to utilize this methodology until the end of 2016, or until a new allocation methodology has been established in new MSP proceedings.

Cost Allocation Formula

Q. Please explain the issue addressed in the testimony of Mr. Lesser with the “75-25” cost allocation methodology.

A. Mr. Lesser attempts to explain how this methodology exacerbates the Company’s fixed costs. The “75-25” methodology allocates fixed generation and transmission costs, in part, based on energy consumption. In the opinion of Mr. Lesser, this methodology has the effect of magnifying the Company’s fixed cost recovery shortfall. Mr. Lesser believes that the “75-25” cost allocation formula leads to inefficient cost allocation, resulting in ambiguous price signals for the Company’s retail customers. He proposes abandoning this methodology, but does not provide an alternative solution or argument.

Q. Does the Company agree with the adjustment?

A. No. In referring to the "75-25" cost allocation formula, Mr. Lesser does not state whether he is proposing a change to inter-jurisdictional allocations or to the cost of service allocations within the state of Utah. If this is related to allocations to customer classes within the state of Utah, the revenue requirement phase of a general rate case is not the appropriate forum for proposing this type of change. Intra-class allocations should be addressed in the cost of service phase of this case. If Mr. Lesser is proposing a change to the 75/25 cost allocation formula for inter-jurisdictional cost allocations the proper forum is the MSP. Either way, this is not an issue that Mr. Lesser should be arguing in this phase of the general rate case.

Naughton Unit 3 Gas Conversion

Q. Does the rate case reflect the Naughton 3 Gas Conversion?

A. Yes. The revenue requirement for this case continues to be 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.

Q. Has the Company requested to delay the Naughton 3 Gas Conversion?

A. Yes. As addressed in the direct and rebuttal testimony of Company witness Mr. Chad Teply, the Company has requested that, as part of the Environmental Protection Agency ("EPA") review of the Wyoming Regional Haze State Implementation Plan, 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 revise 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 approximately $5 million to $6 million.

Q. What is the Company's proposal if the EPA approves a delay in the Naughton 3 Gas Conversion?

A. In my original testimony the Company anticipated a decision prior to rebuttal. However, as described in the testimony of Company witness Mr. Teply, the Company has not received approval to continue the operation of Naughton unit 3 as a coal fired unit. If approval is granted, the Company would propose including the benefits of the continued operation as a coal unit as part of the Company's Energy Balancing Account ("EBA") at 100 percent.

Q. Why would it be appropriate to include this as part of the EBA?

A. One of the major changes related to continued operations as a coal-fired unit will be on net power costs, which are included in the EBA but subject to the 70 percent EBA sharing provisions. Therefore, it would make sense to include all of the changes related to the continued operation as a coal unit in the EBA, but to pass through 100 percent of the effects of the changes so that customers receive the full benefit of the savings. The Company would include the changes related to net power costs, electric plant in service and accumulated depreciation balances, fuel stock balances, generation O&M expense and related tax impacts associated with continued operations in the EBA.

Q. Does this conclude your rebuttal testimony?

A. Yes.