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Department of Commerce
Division of Public Utilities

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ACTION REQUEST RESPONSE

To: Utah Public Service Commission

From: Division of Public Utilities

Chris Parker, Director
Artie Powell, Manager, Energy Section
David Thomson, Technical Consultant
Abdinasir Abdulle, Utility Analyst
Justin Christensen, Utility Analyst

Subject: Docket No. 15-035-51. Action Request from the Commission to review and make recommendations. PacifiCorp's December 2014 Results of Operations. In the Matter of PaciCorp's Financial Reports 2015.

Date: September 29, 2015.

RECOMMENDATION (No Action)

After a review of the above mentioned report, the Division of Public Utilities (''Division") recommends that the Public Service Commission ("Commission") take no action.

ISSUE

On April 30, 2015, Rocky Mountain Power ("Company") filed its December 2014 Results of Operations and a confidential Wind Resources Report for the twelve months ended December 31, 2014 with the Commission. The wind report was provided in compliance with the Commission's final order in Docket No.07-035-93, and included the name, nameplate capacity, actual generation and actual capacity by month for each wind resource. On April 30, 2015, the Commission issued an Action Request to the Division requesting a review of the filing and to make recommendations. The Commission asked the Division to report back by June 1, 2015.

Upon initial review of the filing, the Division determined that the review would require the Division (1) to submit requests for information to the Company and (2) to independently check the Company's spreadsheets used in its filing to obtain regulatory results of operations for 2014. The Company told the Division that its initial request for a reconciliation of the results to its FERC Form 1 and SEC 10K filings for 2014, using their best efforts to respond to the request, would be within 30 days of the request. Also, the Company's responses to the Division's additional follow-up data requests would require an additional 30 days. Taking into consideration the time to analyze the data request responses and the report preparation, the Division requested on May 13, 2015, that the Commission extend the due date of the Division's response to the Action Request to September 30, 2015.

On May 15, 2015, the Commission granted the Division's request for an extension of time to September 30, 2015.

GENERAL COMMENTS, ANALYSIS AND REVIEW

As a result of past informal meetings, which the Division discussed in previous reports on the Company's annual results of operations, there was a change regarding how the unadjusted information would be adjusted to arrive at normalized results. Now actual results are adjusted to arrive at normalized results using two types of adjustments. They are Type A, – reporting and ratemaking adjustments, and Type B, – normalizing adjustments. Future period adjustments have been discontinued. The first semi-annual filing using the new Type A and Type B adjustment method was the Semi-Annual filing filed for the year ended December 31, 2011. Except for these adjustment changes, the rest of the filing's basic format and presentation of information remains the same as in previous filings

The Division's review of the Semi-Annual filing under this Action Request was done using three major review procedures. The first major procedure was comparing information given and adjustments made for the year ended December 31, 2013 Semi-Annual filing to the same information given and adjustments made for the December 31, 2014 Semi-Annual filing. The second procedure was to review a reconciliation provided by the Company that reconciled the year ended December 31, 2014 Semi-Annual filing to the Company's FERC Form1 and its SEC 10K filing for the same period. Third, the Division used the IJA model provided by the Commission to check the Company results of operations filings independently. The Division had no informal meetings with Company during its review of the results of operations for 2014.

Net Power costs are a major operating expense of the Company. For the year ending December 31, 2014, these costs were reviewed by the Division in another docket, Docket No. 15-035-03. The result of the Division's audit regarding Net Power Costs can be found in that docket. The Division also filed reports on the REC Balancing Account in Docket No. 15-035-27. The Division's questions for these items were covered in the above Dockets and will not be addressed in this report.

The Division did do a comparison review of Net Power Cost and REC Balancing account adjustments made to the 2013 and 2014 December 31 filings. For the results of that review, see the Net Power Adjustment Section under the Adjustment Comparison Analysis and Review report heading that follows.

Tab 2 in the Semi-Annual filing is entitled Results of Operations. This section of the filing has a one page summary of actual results for the Total Company and Utah, and normalized results for the Total Company and Utah. The normalized results are obtained by applying the Type A and Type B adjustments. In this Tab the allocation of total cost to Utah is done by using the 2010 MSP Protocol without the ECD (Embedded Cost Differential). The summary also uses a 13-month Average Rate Base. Behind the summary are the detail amounts by FERC account. The detail, also by FERC account, shows the business function of the account and the allocation factor or factors used to allocate total FERC account amounts to Utah. The allocation factors are found in Tab 11 – Reporting and Ratemaking Allocation Factors. Tab 11 has the allocation factors for all

Company's jurisdictions and how they were computed. Actual loads were used in determining many of the allocation percentages. For its Utah filing the Company used only the Utah allocation percentages from Tab 11.

Also in Tab 2 is a page that has user specific information, tax information, and capital structure information. The capital structure information is calculated using a five quarter average from December 31, 2013 to December 31, 2014.

Tab 1 of the Semi-Annual filing is called Summary. This tab starts with actual results for Total Company and Utah allocated, then shows the Type A adjustments for Total Company and Utah Allocated to arrive at amounts for Total Company and Utah Allocated after adjustments. These results are shown under a column with a heading of Reporting and Ratemaking Results. These results are then adjusted for Type B adjustments to arrive at normalized results for Total Company and Utah Allocated. The final normalized results in this Tab agree with those in Tab 2. Tab 2 does not show the Type A and Type B adjustments. This section also has an adjustment summary whereby the Utah allocated reconciled actual results of operations, rate base and tax calculations are shown along with all of the adjustment tabs line item totals (combining A and B adjustments) to arrive at the Utah Allocated Normalized Results. The table on the next page provides some summary information for comparative purposes from the latest filings. All numbers are the Utah Allocated normalized results amounts ($000,000).

	December 2014	June 2014	December 2013
Total Operating Revenues	$2,203	$2,159	$2,108
Total O&M Expenses	$1,253	$1,268	$1,224
Depreciation and Amortization	$ 279	$ 271	$ 265
Taxes Other Than Income	$ 59	$ 58	$ 59
Income Taxes and Deferrals	$ 155	$ 137	$ 135
Operating Revenue for Return	$ 457	$ 425	$ 425
Total Electric Plant	$11,360	$11,123	$10,793
Total Rate Base Deductions	$ 5,354	$ 5,249	$ 5,007
Total Net Rate Base	$ 6,006	$ 5,874	$ 5,786
Earned Return on Rate Base	7.602%	7.230%	7.339%
Earned Return on Equity	9.839%	9.094%	9.174%

Through a stipulation approved by the Commission in the Company's last general rate case[1] the Commission authorized an Earned Return on Equity amount of 9.80%. The Division notes that the Semi-Annual filing for the year ending December 31, 2014 shows an earned return on Equity of 9.839% which is .039% greater than the authorized Return on Equity of 9.8%. As shown above for the Semi-Annual filings for the years ending June 2014 and December 2013, the Company is earning less than its authorized Return on Equity of 9.80%. The Division will monitor the return on equity percentage in the Semi-Annual filing for the year ending June 2015 to see it the return on equity percentage remains above 9.8%.

Tab 9 of the filing is labeled Rolled-in. The amounts and the results of operation in this Tab are exactly the same as Tab 2.

[1] Docket No. 13-035-184

A comparison of the numbers for years above indicates a gradual increase in Revenues and O&M expenses except for 2015 O&M which decreased. Also, the total net rate base is increasing along with the earned return on rate base and the earned return on equity except for the earned return on equity for June 2014 which decreased. Depreciation is also increasing due to the increase in Total Electric Plant.

For the last General Rate Case the Overall Capital Structure and Cost of Capital was stipulated as follows:

Component	Percent of Total	Cost	Weighted Average
Long-term Debt	48.55%	5.20%	2.53%
Preferred Stock	0.02%	6.75%	0.00%
Common Stock Equity	51.43%	9.80%	5.04%
TOTAL	100.00%		7.57%

In this Semi-Annual the calculated five quarter average Overall Capital Structure and Cost of Capital is:

Component	Percent of Total	Cost	Weighted Average
Long-term Debt	48.17%	5.20%	2.503%
Preferred Stock	0.02%	6.75%	0.001%
Common Stock Equity	51.81%	9.80%	5.077%
TOTAL	100.00%		7.582%

Using the above Semi-Annual amounts and substituting the authorized return on equity percentage with the return on equity from the filing of 9.839% as shown above you get the following results:

Component	Percent of Total	Cost	Weighted Average
Long-term Debt	48.17%	5.20%	2.503%
Preferred Stock	0.02%	6.75%	0.001%
Common Stock Equity	51.81%	9.839%	5.097%
TOTAL	100.00%		7.601%

The filing has a Tab 10 that is labeled 2010 Protocol With ECD. This Tab uses normalized allocation factors from Tab 12 to allocate Total Company normalized results to Utah. Tab 12 uses temperature normalized loads to derive its allocation factors. Overall, this method causes fewer costs to be allocated to Utah. The Earned Returns on Equity for Tab 10 for December 2014, June 2014 and December 2013 are 9.600%, 8.831%, and 9.011%, respectively.

Per the last general rate case, the stipulated Utah base Net Power Costs were $630.0 million on an annual basis. For the December 2014, June 2014, and December 2013 Semi-Annual filings the Utah Net Power Cost were computed to be $689.8, $696.3, and $659.6 million, respectively.

As with last year filing the Company has chosen to include postretirement welfare plan balances in its December 2014 results of operations These balances were included in the last general rate case filing Docket No. 13-035-184. The Company's rate case testimony explained why it believed these balances were (or should be) included rate base. Whether or not the Commission will accept these balances in rate base was not determined by the settlement in the last rate case. There is no Commission order supporting the use of this adjustment to obtain Utah normalized results of operations for the semi-annual filing.

For analysis purposes the Division has run the JAM without the postretirement welfare plan balances generating a new results of operations summary. The amounts used to back out the balances from the JAM were provide by the company. We then compared the new results of operations summary we produced to the Company's original results of operations summary with the postretirement welfare plan balances as filed with the Commission. Exhibit A has the results of the comparison. The pertinent results for not including postretirement welfare plan balances is as follows: not including increased operating taxes by $658,499; decreased rate base by $115,463,740; decreased rate base deductions by $46,140,065; increased return on rate base from 7.602% to 7.780% (plus 0.078) an increase of 1.03%; and increased return on equity from 9.839% to 9.989% (plus 0.150) an increase of 1.50%. See exhibit A for details.

As in past filings, the Company has restated generation overhaul expenses to constant dollars when it does its normalizing adjustment for generation overhaul expenses (see adjustment page 4.6.1 in the filing).

In its August 11, 2008 Order issued in Docket No. 07-035-93 and in its February 18, 2010 Order issued in Docket No. 09-035-23 the Commission directed that historic costs should not be inflated prior to determining the normalized four-year average expense level. As stated above, the Company in its rate case filings subsequent to the above orders has restated overhaul expense amounts in constant dollars. In past rate cases the Company has written testimony to support it doing so. The Division in recent rate case testimony has also provided reasons and analysis why historical costs should be adjusted to constant dollars. However, all of the rate cases subsequent to the above Orders on this matter have been settled with this restating to constant dollars not addressed in the stipulated settlements.

Again, as a matter of analysis, the Division wanted to see the impact of adjustment 4.6 to results of operations using historical dollars instead of constant dollars as filed by the Company in the 2014 filing. Using the same method and analysis as that used for prepaid pension costs above, the results were as follows: not including constant dollars decreased O&M expense $684,540; increased taxes by $259,856; decreased rate base working capital $6,964; increased return on rate base from 7.602 to 7.610 (plus 0.007) an increase of 0.09%; and increased return on equity from 9.839 to 9.853 (plus 0.014) an increase of 0.14%. See exhibit A for details.

Also in Exhibit A, the Division has included a comparison of the original results of operations summary with one prepared by the Division without prepaid pension costs and the constant dollar adjustment to generation overhaul expenses. The results are as follows: decreases O&M expenses $684,540; increases taxes $918,355; decreases rate base $115,463,740; increase working capital by $3,834; decreases rate base deductions $46,140,065; increases return on rate base from 7.602% to 7.687% (plus 0.085) an increase of 1.12%; and increases return on equity from 9.839 to 10.003 (plus 0.164) an increase of 1.67%. See exhibit A for details.

The Division notes that all adjustments in the Results of Operations are consistent with the Company's last GRC filing, unless specific adjustments were called out in the settlement stipulation or Commission Order. New adjustments appear to be consistent with Commission Orders under Dockets subsequent to the last GRC that would impact ROO, such as the Deer Creek adjustment.

RECONCILIATION ANALYSIS AND REVIEW

As noted above, one of our major review procedures was to have the Company provide a reconciliation of the Semi-Annual results to the Company's FERC Form 1 and SEC Form 10K. The Company's Semi-Annul filing to the Commission is based on FERC accounting and FERC accounts. The first reason for this reconciliation is to make sure that the unadjusted historical information in the Semi-Annual filing results of operations provided by the Company is reconcilable to the FERC Form 1 data. Through the reconciliation of the Semi-Annual filing, the Division can get assurance that the form and the accounting for the Semi-Annual filing are the same as that provided to another outside regulator, in this case the FERC.

The second reason for the requested reconciliation is that if the 10-K results can be reconciled to the Semi-Annual filing, then the Division can take into account the external auditor's 10K audit opinion on the results shown in the Company's year-end filing of its Semi-Annual. The Division can look to this audit to obtain assurance as to accounting correctness and accuracy for Semi-Annual base unadjusted historical information under this review.

The Company's filing of its 10-K with the Securities and Exchange would be based on historical information from the Company's books and records. The 10-K filing is based on GAAP accounting (General Accepted Accounting Procedures) but the information for that accounting also is the same base information that is used in the FERC Form 1 and the Semi-Annual filing. The SEC filing's historical information is audited by independent external auditors of the Company. The external auditors have expressed a positive opinion on the fairness of the Company's representations on its financial statements according to GAAP for the same period as the Semi-Annual report the Division is reviewing in this memorandum; the opinion issued by the external auditor was what is sometimes termed a "clean" opinion. The Company's books and records providing the account amounts for the financial statements and for the FERC Form 1 and the Semi-Annual were audited by the External Auditor using Generally Accepted Auditing Procedures as part of its procedures to arrive at its issued opinion.

Third, once the reconciliation is provided, the Division can review the reconciled items to see if they make sense and are proper additions or eliminations to arrive at a proper base or proper starting point for unadjusted historical results of operations in the Semi-Annual filing. This proper base is then adjusted to arrive at Utah normalized results of operations for regulation purposes.

The Division did receive the above requested and explained reconciliation. Specifically, the Company prepared the following reconciliations:

1. Income Statement: 10-K to FERC Form 1.
2. Income Statement: FERC Form 1 to Results of Operations (unadjusted).
3. Balance Sheet: 10-K to FERC Form 1.
4. Balance Sheet: FERC Form 1 to Results of Operations (unadjusted, yearend basis).

These reconciliations are provided with this report as DPU Exhibits B through E. As part of its review procedures, the DPU compared the reconciliations provided by the Company for its

December 2014 review with the reconciliations provided by the Company for its December 2013 review.

The reconciliation format was identical from this year to last year with the vast majority of the reconciliation items from year to year being the same. This was expected since the base accounting and the chart of accounts from year to year follows GAAP and FERC rules and regulations that are highly consistent, with little if any changes from year to year. This consistency provides comparisons that quickly point out differences from year to year in format and reconciling items. One noted major difference was the GAAP treatment of the Deer Creek mine closure as compared to regulatory treatment. Due to the consistency of the reconciling material from this year to the last, no data requests having to do with the reconciliations for December 2014 were required. The explanations for the GAAP to regulatory differences for the Deer Creek Mine closure provided in this Docket were consistent with those provided in the Deer Creek Closure Docket (No. 14-035-147).

The information provided by the Company in its reconciliations has enabled the Division to better understand why particular financial items are different between the three types of reports (Form 10K, FERC Form 1 and Utah Results of Operations). Due to the large number of differences between the reports and the detail involved, this report will not attempt to explain all of the differences. The explanations for the differences are, however, shown in DPU Exhibits B through E. The Division has reviewed the Company's explanations for the differences and at this time the Division does not have any reconciliation concerns. However, the Division reserves the right to challenge certain reconciliation treatments or methodologies that may get carried over to future Results of Operation reports or other proceeding if the Division concludes challenges are appropriate. For example, the Division may at a future date determine that an item that is currently considered "regulatory" should in fact be "non-regulatory" and should not be included in the Results of Operations.

It appears to the DPU, after review of the reconciliations, that the December 2014 results of operations on a total Company and unadjusted basis is derived from the same base numbers as those found in the Company's 10K filing to the Securities and Exchange Commission and to the FERC Form 1 filing with the Federal Energy Regulatory Commission.

ADJUSTMENTS COMPARISON ANAYLSIS AND REVIEW

Another review procedure was to compare the adjustments made to the Utah Results of Operations for the year ended December 31, 2014 to the adjustments to the Utah Results of Operations for the year ended December 31, 2013. In the past ten years, the majority of the rate cases in Utah have been settled. Thus, during this period the adjustments to arrive at Utah regulated results of operations have been consistent with very little change. Generally, the Commission's orders and regulatory precedents used to arrive at Utah regulatory results of operations have been generated many years before and so the regulatory adjustments from one semi-annual results of operation filings to another are basically the same. However, as noted in previous filings by the Division future period or Type 3 adjustments have been discontinued.

Both Type A and Type B adjustments were compared. In the 2014 and 2013 filings, the adjustments are summarized and explained in detail by various categories which are broken out by Tab Sections in the filing. The adjustment Tabs in the filing are numbered and are as follows: Tab 3 - Revenue Adjustments; Tab 4 - O&M Adjustments; Tab 5 - Net Power Cost Adjustments; Tab 6 - Depreciation and Amortization Adjustments; Tab 7 - Tax Adjustments; and Tab 8 - Rate Base Adjustments.

One purpose of the comparison was to note material differences between the years and to determine if the differences were proper. Accordingly the Division submitted comparison questions through data requests to the Company. Another purpose was to have the Division look at the 2014 adjustments to determine if the presentation, explanations, and balances were consistent and accurate and that the assumptions and the computation of the adjustments seemed to be proper and accurate. The Division noted that the adjustments in the adjustment tabs were consistent with adjustments that the Company makes to results of operations in its General Rate Case filings.

Some of those adjustments do not follow commission orders or were contested by parties during the rate case prior to settlement without resolution or agreement.

Based on the Division's comparison analysis and its review of the adjustments, it notes the following.

Revenue Adjustments:

- In the filing, the reason the temperature normalization adjustments for Residential and Commercial are greater than Industrial is the kilowatt-hour (kWh) usage of the residential and commercial class are more temperature sensitive than industrial class usage. Therefore, when temperatures are below or above normal the temperature normalizing adjustment will be larger for the residential and commercial class than the industrial class.
- In response to a Division inquiry on revenue normalization between years, the Company provided a detailed explanation. This explanation is provided in Exhibit F which is a response to DPU Data Request 2.1 (c).
- Renewable Energy Credits (REC) revenue in 2014 is down from 2013 because historically, the majority of the Company's revenue from the sales of REC came from the California compliance market. Recently, the product definitions adopted by the State of California under SB2 (1X) and under California Public Utility Commission (CPUC) Renewable Portfolio Standards (RPS) Product Content Decision, specifically disadvantage out-of-state renewable energy. This has limited the Company's ability to sell RECs into the California market, since the Company does not have renewable generation in the qualifying locations for a Bucket One product.
- The biggest reason for the 2014 increase in wheeling revenue is the additional long-term point-to-point (PTP) contract capacity added in 2014. This results in approximately a $7 million increase, inclusive of the rate change from the last rate case applicable to this ROO filing period.
- The large decrease in the Schedule 98 REC Revenue as compared to last year is due to the decrease in REC revenues in base rates. In 2013, there was $20 million in rates as

determined in Docket No. 11-035-200. In 2014, the amount decreased to $7.3 million as determined in Step 2 in Docket No. 11-035-200 and Step 1 in Docket No. 13-035-184. This created a larger deferral to be collected from customers in 2013 than 2014. The minimal change in the Net Power Cost accrual is due to the fact that an increase in the deferral as part of the Energy Balancing Account was offset by an increase in the amount that was adjusted downward as part of the stipulation in Docket No. 14-035-31.

O&M Adjustments:

- As requested by the Division, a detailed explanation of the gains and losses shown on Page 4.1 the 2014 filing was provided by the Company. See Exhibit G.
- The Broker incentive recorded in 2013 was reversed in 2014 because the Broker incentive accruals were booked to the incorrect FERC Account and should have been booked to FERC Account 924 – Property Insurance. The reversal takes care of this issue on the Company's books. However, since the initial accrual and its reversal were in separate base periods, the adjustment on Page 4.1.1 of the filing was needed.
- Even though the DSM program cots are removed from the filing because they are through separate tariff riders, the Division asked why there was such a large increase to DSM costs in 2014. The increase was due to new equipment being purchased for the Cool Keeper Program along with increased participation in LED lighting with the Home Energy Savings Program.
- In 2014, there was an insurance adjustment because the Commission ruling in Docket No. 07-035-93 ordered use of the case basis method of accounting for injuries and damages. When the cash basis method accounting is used, there is no reserve. This cash basis method was used in the most recent General Rate Case and the Company continues to use this approach.
- The purpose of the Generation Overhaul adjustment to adjust the base period expense to a historical four-year average. The primary driver for the adjustment decrease on page 4.6 is the increase in base year expense from $22.6 million in 2013 (after removing $2.7 million of Carbon plant due to the April 2015 retirement) to $33.8 million in 2014. Although the

size of the generation overhaul expense adjustment decreased from 2013 to 2014, the historical four-year average held fairly constant at $36.4 million (with $0.9 million Carbon removed) for calendar year 2013 and $35.4 million for calendar year 2014 on a Total Company basis.

- The Wind Turbine Oil Change adjustment in the December 2013 filing normalized what was booked in the base year by taking a three year historical average of the expense. The Company has since normalized the cost in actual result for wind turbine oil changes and therefore no adjustment was needed in 2014 to adjust the per books expense.
- Per the Company, the Uncollectible Expense adjustment – page 4.7, was done in the past several general rate case in Utah, Docket Nos 13-035-184, 11-035-200, and 010-035-124. The adjustment is necessary to correctly align the normalized revenue with the uncollectible expense.

Net Power Cost Adjustments:

- The Division asked the Company two general net power cost (NPC) questions from the filing. (a) Why the large increase in the Type B NPC normalization adjustment from negative in 2013 (-29,458,507) to positive in 2014 (2,749,955)? (b) Why the large decrease in type A normalization adjustment form 2013 (positive 1,825,348) to 2014 (negative 12,078,303)? (Page 5.1).
- The Company's response was as follows: (a) The Type B normalization from 2014 was a result of slightly lower than normal hydro generation and slightly higher than normal load, which resulted in offsetting adjustment to net power cost, and a small overall impact. The Type B normalization from 2013 was a result of significantly lower than normal hydro generation and significantly higher than normal load, both of which resulted in a downward adjustment to Net power cost. (b) The change in the Type A adjustment is mainly due to an increase to the NPC deferral amortization account. Many of the NPC deferrals have been amortized over multiple years and each year new NPC deferrals are added to the amortization account. Therefore, the NPC amortization account continues to grow as new NPC deferrals are accumulated before the past net power cost deferrals are fully amortized.

Tax Adjustments:

- Interest true up is the difference between normalized interest and unadjusted interest expense. The normalized total rate base for 2014, used for the calculation of normalized interest expense, was large compared to the 2013 normalized rate base. The rate base increase was mainly due to the rise in gross Plant in Service by $500 million on a Utah allocated basis. This contributed to the 3.8 percent increase to total net rate base year over year driving the need for a smaller interest true up adjustment. The primary driver in the decrease of investment in the Trapper Mine and the Bridger Mine is due to the continued depreciation of mine assets.
- In December 2014, the Tax increase Prevention Act of 2014 (the Act) was signed into law, extending 50 percent bonus tax depreciation for qualifying property purchased and place in-service before January 1, 2015 and before January 1, 2016 for certain longer lived assets. The Act was the primary driving factor for the year-over-year increase in the Accumulated Deferred Income Taxes (ADIT) balances, including ADIT-Utah. Specifically for accelerated Amortization of Pollution Control, Hunter Unit 1 clean air scrubber was place into service in 2014 with bonus tax depreciation taken into account.

Rate Base Adjustments:

- The Powerdale hydroelectric plant was fully decommission and the associated regulatory assets were fully amortized by the end of calendar year 2013. No further adjustment was necessary for calendar year 2014.
- In the 2013 Miscellaneous Asset Sales and Removals Adjustment the Company pulled out assets that were sold or removed (i.e. the sale of Snake Creek hydroelectric plant, the removal of Deseret power’s portion of the Hunter Unit 2 scrubber and turbine upgrade, the decommissioning of the Condit hydroelectric plant, and the sale of St. Anthony Hydro plant in Idaho). These assets were not in the Calendar year 2014 unadjusted data, so no adjustments were necessary to remove them. The Company did not have any other assets

that were sold or removed during calendar 2014; thus no adjustment was included in the 2014 Result of Operations (ROO).

- The Regulatory Asset adjustment in December 2013 Utah ROO reflected only the adjustment to Klamath Relicensing and Process Cost amortizations. In the current results (December 2014), the adjustment to this amortization expense was made in the Klamath Hydroelectric Settlement Agreement (KHSA) Adjustment (page 8.7-8.72.). No other adjustment to Regulatory Assets was necessary.
- The Cash Working Capital (CWC) adjustment, adjusts the CWC balance from unadjusted levels as calculated in the normalized ROO report. CWC is calculated by taking total operation and maintenance (O&M) expense allocated to the jurisdiction and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. CWC components are calculated for each adjustment individually within the Jurisdictional Allocation Model (JAM). The CWC Adjustment in 2014 is less than half of that corresponding adjustment in 2013 because the aggregate impact of normalizing adjustments on total O&M and allocated taxes is smaller in 2014 than 2013. In other words, 2014's CWC balance on an unadjusted basis in more closely aligned with 2014's normalize CWC balance than the corresponding balances in 2013.
- Trapper mine rate base increased due to an increase in property, plant, and equipment associated with the mine. Bridger mine rate base increased due to an increase in pit inventory caused by fuel quality issues and reduced burn rates at the Bridger plant.
- Customer advances for construction are deferred credit accounts representing cash advances paid to the utility by customers requiring construction of facilities on their behalf. Customer advances for construction balances fluctuates each year due to the size and complexity of each job, when it started, and how many jobs are in progress for each state.
- PacifiCorp is operating the Klamath project consistent with the requirements of the Klamath Hydroelectric Settlement Agreement (KHSA). The Klamath settlement parties,

including PacifiCorp, continues to advocate for the passage of Klamath legislation now pending before United States congress. Adjustment 8.7, consistent with the stipulation in Docket No. 11-035-200, includes amortization of the recovery of relicensing and process costs with a carrying charge at the authorized long-term cost of debt. Since carrying charges will continue to be accrued, the net unrecovered relicensing and process cost are removed from rate base in this adjustment.

- The division requested from the Company to expand its explanation of adjustment 8.8. Its expanded explanation is as follows:

  What the Carbon Plant Closure depreciation deferral is: This depreciation study implemented January 1, 2014 accelerated the depreciation rate at Carbon Plant to enable early retirement in April, 2015. The new depreciation rate also included a provision to provide for reclamation costs. In Utah, Idaho, and Wyoming the increased depreciation was deferred to regulatory assets to be amortized to expense after the Carbon Plant was retired. This was done to avoid rate shock resulting from the Carbon closure.

  Treatment of depreciation deferral in unadjusted results: This deferral of depreciation expense in these three states was accomplished on the books of the Company by crediting depreciation expense for the amount of the deferral in these three states and charging their regulatory assets. The credit to depreciation expense was allocated on a system generation (SG) basis. The credit needed to be allocated on a situs basis to Utah, Idaho, and Wyoming.

  What Adjustment 8.8 does: This adjustment reverses the system credit to depreciation expense in unadjusted results and credits it to situs amortization expense in each of the three states.

  Page 8.8.2: This page shows the detail of the depreciation expense deferral in each state for the year 2014. The last two columns show the actual allocation factor and the correct allocation factor, which are the basis of this adjustment.

- Adjustment 8.9 deals with the Deer Creek mine closure. In 2014 the Company made the decision to close the Deer Creek mine. Because of this intent in 2014, under generally accepted accounting principles an entry needed to be made to set up regulatory assets. For regulatory purposes, the Deer Creek mine closure was filed with the Public Service Commission for approval of the proposed accounting. For regulatory accounting purposes the Company did not record any entries until the assets were sold, which did not happen until June, 2015. For this reason, the December, 2014 entry that was made to reflect the Deer Creed closure was removed from the ROO.

Reporting and Ratemaking Allocation Factors:

- Allocation factors are mainly driven by loads, so the main factors that would have impacted the Utah allocation factors for calendar year 2014 would be energy usage and Utah's timing and contribution to the system coincidental peak.

INDEPENDENT MODEL RESULTS ANALYSIS AND REVIEW

The Division used the IJA model provided by Commission staff to model a results of operations for the year ended December 31, 2014. This was then compared to the results of operations provided by the Company for the same period. There were only minor differences in a few areas that were not material. The Division believes these differences were due to the fact that the Division's results did not use iteration and the Company's results did use iteration. This independent check supports the results provided by the Company as being properly computed and presented, with differences being of no consequence.

CONCLUSION

After performing the above procedures and after reviewing the results obtained from those procedures, nothing came to the Division's attention during its review that was of material significance suggesting modification of the filing or action to change the Results of Operations as filed. Therefore, the Division recommends that the Commission take no action at this time.

cc: Michele Beck, Office of Consumer Services
Bob Lively, Rocky Mountain Power