ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple
Salt Lake City, UT 84116

July 28, 2017

Erika Tedder
Division of Public Utilities
160 E 300 S, 4th Floor
Salt Lake City, UT 84114
dpudatarequest@utah.gov
etedder@utah.gov (C)

RE: UT Docket No. 17-035-15
DPU 2nd Set Data Request (1-10)

Please find enclosed Rocky Mountain Power's Responses to DPU 2nd Set Data Requests 2.1-2.10. Also provided are Attachments DPU 2.1 –(1-2), 2.2, 2.5, and 2.8 -2. Provided on the enclosed Confidential CD are Confidential Attachments DPU 2.8 -1 and 2.10 –(1-2). Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules 746-1-602 and 603.

If you have any questions, please call Tarie Hansen at (801) 220-2053.

Sincerely,

Bob Lively /DTS

Bob Lively
Manager, Regulation

DPU Data Request 2.1

Revenue Adjustments

2.1.1. The temperature normalizing adjustment (3.1) from the previous year was 305,888 and this year was (34,131,923), a difference of (34,437,811) could you please explain the difference.

2.1.2. The revenue normalizing adjustment (3.2) from the previous year was (118,405,447) and this year was (30,477,057) a difference of (87,928,390) could you please explain the difference.

2.1.3. The REC revenue allocation (3.4) from the previous year was 527,946 and this year it was 1,458,329 a difference of 930,383, could you please explain the difference.

2.1.4. The wheeling revenue adjustment (3.5) from the previous year was (296,830) and this year it was (2,970,877) a difference of (2,674,047) could you please explain the difference.

2.1.5. The misc. general expense & revenue adjustment (4.1) from the previous year was (339,499) and this year it was (5,071,069) a difference of (4,731,570) could you please explain the difference.

2.1.6. The Deer Creek Mine closure adjustment (8.9) from the previous year was -0- and this year it was (8,859,991) a difference of (8,859,991) could you please explain the difference.

Response to DPU Data Request 2.1

2.1.1 The temperature normalization adjustment for 2016 (page 3.1) is different from 2015 due to differences in temperature in 2016 versus 2015 as compared to normal temperatures.

2.1.2 Please refer to Attachment DPU 2.1 -1, which provides the category detail of the differences between calendar years 2015 and 2016.

2.1.3 The difference between the renewable energy credit (REC) revenue reallocation adjustments for the results of operations (ROO) reports for calendar years 2015 and 2016 is primarily due to the difference in the amount of REC deferrals, which are reversed in this adjustment. REC deferrals were $1,824,872 in calendar year 2016 compared to $150,954 in calendar year 2015.

2.1.4 The wheeling revenue adjustment normalizes wheeling revenue to remove out-of-period and one-time adjustments. Although the adjustment was higher in the calendar year 2016 ROO report compared to the calendar year 2015 ROO report, it is important to note the overall amount of wheeling revenue after the adjustment. Adjusted wheeling revenue in calendar year 2015 was $92,108,910 (page 3.5) compared to $93,880,823 in calendar year 2016 (page 3.5), which is less than a 2 percent change.

2.1.5 To prepare this adjustment, the Company reviews certain accounts for accounting entries that should be removed from regulatory results. In calendar year 2016, there were more entries that needed to be removed than in calendar year 2015.

2.1.6 The closure of the Deer Creek mine resulted in some assets being sold, the return on which had been built into rates. In addition, there have been savings on the post-retirement plan due to the United Mine Workers of America (UMWA) settlement. Until rates are re-set, the Company will accrue a regulatory liability for these by reducing revenues. Please refer to Attachment DPU 2.1 -2.

DPU Data Request 2.2

Operating Expense Adjustments

2.2.1. The following are adjustments in 2015 but not 2016:"Idaho Irrigation Load Control Program" (4.2 in 2015), "DSM Expense Removal" (4.3 in 2015), "Generation Overhaul Expense" (4.5 in 2015), "Uncollectible Expense" (4.6 in 2015), and "Miscellaneous Asset Sales & Removals" (8.10 in 2015). The following adjustments were in 2016 but not in 2015: "Generation Expense Normalization" (4.3), and "Revenue Sensitive Items and Uncollectible Expenses" (4.4). Are some of these the same adjustments under a different name? If so, which accounts are the same? If not, please explain why they were adjusted in 2015/2016 and not the other year.

2.2.2. The net power cost adjustment (5.1) from the p year was (31,472,926) and this year it was 2,096,731, a difference of 33,569,655, could you please explain the difference.

2.2.3. The customer service deposits adjustment (8.6) from the previous year was 983,444 and this year was 759,018 a difference of (224,425) could you please explain the difference.

2.2.4. The Deer Creek Mine closure adjustment (8.9) from the previous year was 393,246 and this year was (1,399,156) a difference of (1,792,402) could you please explain the difference.

2.2.5. Please explain the operating expense adjustments for the Carbon Plant closure (8.8) after providing the information in 4.1 below. The Division would be receptive to a phone meeting or face to face meeting rather than a written response.

Response to DPU Data Request 2.2

2.2.1 Please refer to the explanations provided below:

(a) Idaho Irrigation Load Control Program – Historically, the payments and program costs related to the Idaho irrigation load control program were booked in the Company's system on a System Generation (SG) factor, which required an adjustment to correctly allocate the costs directly to the state of Idaho in the Utah results of operations (ROO) reports. In the 2016 ROO, the Company began booking the payments and the majority of the program costs directly to Idaho, which eliminated the need for an adjustment. A small amount of program costs were booked on the SG factor and are removed from results in the Miscellaneous Expense and Revenue adjustment (see page 4.1.1 in the December 2016 ROO).

(b) Demand-Side Management (DSM) Expense Removal - In the 2015 ROO report, DSM expense and revenues were included in the unadjusted data and removed through adjustments. Beginning in the 2016 ROO report, DSM expense and revenues were no longer included in the unadjusted results, so no adjustment to remove them was necessary.

(c) Uncollectible Expense – The adjustment is included in 2016 ROO as "Revenue Sensitive Items and Uncollectible Expense (see page 4.4).

(d) Miscellaneous Asset Sales and Removals – This adjustment is included when there are assets that were sold or removed during the historic period that need to be removed from results. There were no major asset sales or removals during calendar year 2016.

(e) Generation Expense Normalization –This adjustment was included in the 2015 ROO as "Generation Overhaul Expense" (see page 4.5).

(f) Revenue Sensitive Items and Uncollectible Expenses – This adjustment was included in the 2015 ROO as "Uncollectible Expense" (see page 4.6).

2.2.2 The difference is primarily driven by two factors:

(1) Historically, net power cost deferrals related to net power costs mechanisms were included in unadjusted data. A correcting adjustment was necessary to exclude the deferrals from net power costs (NPC). Beginning in the 2016 ROO, NPC deferrals are no longer included in the unadjusted data; consequently, the adjustment to remove the deferrals is no longer required.

(2) Normalized hydro generation for the 2016 ROO was closer to actual hydro generation, resulting in a smaller adjustment. For the 2015 ROO, the difference between normalized hydro generation and actual hydro generation was greater.

2.2.3 The difference was caused by a decrease in the customer deposits interest rate from 6 percent to 4.45 percent, resulting in a reduction to the interest paid to customers on their deposits.

2.2.4 Please refer to Attachment DPU 2.2.

2.2.5 The Carbon Plant ceased operation in April 2015. Residual operation and maintenance (O&M) expenses that were booked in 2016 were removed in the adjustment.

DPU Data Request 2.3

Rate Base Adjustments

2.3.1. The Carbon Plant closure adjustment (8.8) from the previous year was -0- and this year was (16,027,967), could you please explain the difference.

2.3.2. The change in allocation factors to normalized loads adjustment from the previous year was (87,359,024) and this year was (162,671,689), a difference of (75,312,665), could you please explain the difference. (From adjustment summary tab in Excel Jam).

Response to DPU Data Request 2.3

2.3.1 Carbon plant balances and related expenses were removed from the Company's books during 2016, but were still included in unadjusted results in the 13-month average rate base. These amounts were removed in Adjustment 8.8. The Carbon plant balances and related expenses in the calendar year 2015 results of operations (ROO) were not removed because the plant was closed during 2015, so an adjustment to remove them from calendar year 2015 ROO would be a pro-forma adjustment, which are not included in Utah's ROO reports.

2.3.2 In 2015 and 2016, total Company electric plant in service (EPIS) less situs amounts was allocated 94 percent to 95 percent on the system generation (SG) factor. The SG factor decreased approximately 82 percent more in 2016 than in 2015 from the reporting and ratemaking factors to the normalized factors. This 82 percent aligns closely to the percentage decrease shown in the 'change in allocation' dollars. Please refer to the table provided below:

SG Factor	Reporting and Ratemaking %	Normalized %	Change		Allocation Change Dollars
2015	44.21%	43.74%	(0.46)%		(87,359,024)
2016	43.87%	43.02%	(0.85)%		(162,671,689)
Change	(0.34)%	(0.73)%	(0.38)%		(75,312,665)
Change %	**(0.78)%**	**(1.66%)**	**82.38%**		**86.21%**

DPU Data Request 2.4

Other Adjustments

2.4.1. There were significant adjustments in revenues, operating expenses, and rate base for "Change in Allocation Factors to Normalized Loads", please describe what's driving those differences in addition to the question in 2.3.2.

Response to DPU Data Request 2.4

2.4.1 There are various factors that may cause differences in revenues, operating expenses, and rate base in the "Change in Allocation Factors to Normalized Loads" column shown on page 1.4 of the Utah Results of Operations (ROO) report – December 2016.

(a) The level of total Company adjusted amounts prior to applying the normalized loads.

(b) The net percentage differences between the reporting and rate making factors and the normalized factors. The greater the difference between these two sets of factors, the greater the difference.

(c) The net differences between the factor inputs for 2015 and 2016. These differences may include but are not limited to the following:

i. Unadjusted data amounts by indicator excluding situs amounts.

ii. The Utah peak and energy loads as a percentage of the total system loads.

iii. The tax factors derived from the PowerTax system.

iv. Number of Utah customer billings as compared to the total Company billings.

DPU Data Request 2.5

We compared normalized Utah results with the previous year using the results of operations summary pages (2.2) to identify significant changes, please describe what's driving changes to the following accounts from the previous year:

Revenues

2.5.1. Normalized general business revenues declined by 1.07%, or (21,213,865); line 2.

2.5.2. Normalized special sales decreased by 34.31%, or (39,487,909); line 4.

Response to DPU Data Request 2.5

2.5.1 Please refer to Attachment DPU 2.5, which provides the category detail of the differences between calendar years 2015 and 2016.

2.5.2 Special sales for resale on a total Company basis decreased by $92.7 million from 2015 to 2016 primarily due to a reduction in the wholesale sales market transactions. Lower market transactions were due to lower market prices.

DPU Data Request 2.6

We compared normalized Utah results with the previous year using the results of operations summary pages (2.2) to identify significant changes, please describe what's driving changes to the following accounts from the previous year:

Operating Expenses

2.6.1. Steam production expenses decreased by 5.37%, or (28,583,021); line 9.

2.6.2. Other power supply decreased by 8.54%, or (34,447,476); line12.

2.6.3. Federal and State taxes increased proportionally to a decrease in deferred taxes, can you confirm that those changes are just reversing temporary differences in deferrals or if there were other material or unusual transactions driving those changes; line 24-29.

Response to DPU Data Request 2.6

2.6.1 A decrease of $26,583,021 in steam production was caused by a decrease in net power costs (NPC) expense.

2.6.2 A decrease of $34,447,476 was caused by a lower NPC (specifically purchased power cost and fuel cost) expense in 2016.

2.6.3 The corresponding increase from 2015 to 2016 in Federal and State income taxes and decrease from 2015 to 2016 in deferred income taxes is primarily related to a decrease in the 2016 capital additions compared to 2015 capital additions.

DPU Data Request 2.7

We compared normalized Utah results with the previous year using the results of operations summary pages (2.2) to identify significant changes, please describe what's driving changes to the following accounts from the previous year:

Rate Base

2.7.1. Electric plant in service increased by 55,802,736 (line 26), where there any unusual or notable items driving that increase.

Response to DPU Data Request 2.7

2.7.1 The following items contributed to the December 2016 electric plant in service (EPIS) balance change from the previous year:

- Sigurd Red Butte Crystal 345 kilovolt (kV) line in service May 2015;
- Bridger Selective Catalytic Reduction (SCR) Unit 3 in service in November 2015;
- Deer Creek mine removed from Company books June 2015;
- Change in allocation factors to normalized loads;
- Carbon Plant closure adjustment; and
- Bridger SCR Unit 4 in service November 2016

DPU Data Request 2.8

Please provide a status report on the Carbon Plant demolition. Please describe whether demolition has begun or not, what percentage complete is the dismantling project at December 31, 2016, through December 31, 2016 the costs that have gone into closure by significant category and how does that compare to the budgeted demolition/closure costs and any other pertinent information. Please provide direct and indirect applicable account balances per inception showing yearly accounting entries with explanations through year-end 2016 and May 31, 2017.

Response to DPU Data Request 2.8

As of June 23, 2017, the two major contractors are both demobilized from the Carbon plant site, including the landfill area, and are near to final completion. Once complete, the warranty period will commence. The vegetative establishment period has already started.

At December 31, 2016, asbestos abatement has been completed in all areas including the ductwork, major piping, boilers, and electrostatic precipitators (ESP). The following major buildings and equipment have been demolished and removed including the coal unloading facility, coal conveyor (outside plant), cooling tower (both units), ash silos, 46 kilovolt (kV) switchyard, warehouse building, training building, administration building, ESP, stacks, Unit 2 boiler, major transformers (generator step-up and auxiliary for both units), and other large equipment including pumps, pressure vessels, tanks, motors, fans, etc. At year-end all permits, submittals, and engineering plans were complete.

Please refer to Confidential Attachment DPU 2.8 -1 for a summary of project costs through December 31, 2016 by major category. The total project costs were $22.9 million at December 31, 2016, compared to the previously projected cost of $20.1 million.

Please refer to Attachment DPU 2.8 -2 for a summary of accounting entries through year-end 2016 and at May 31, 2017.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules 746-1-602 and 603.

DPU Data Request 2.9

Please provide a status report on the Klamath River dam removal situation. Please describe the current status, expected timelines, and any significant changes from last year.

Response to DPU Data Request 2.9

The Klamath Hydroelectric Settlement Agreement (KHSA) was amended on April 6, 2016, to provide for a dam removal process under the authority of the Federal Power Act administered by the Federal Energy Regulatory Commission (FERC). Under the Amended KHSA, PacifiCorp will seek approval to transfer the four dams (J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate) slated for removal to the Klamath River Renewal Corporation (KRRC), a non-profit entity formed solely for the purpose of removing the Klamath dams. On September 23, 2016, PacifiCorp and the KRRC filed a joint application with FERC requesting that:

(1) the existing license for the Klamath Hydroelectric Project be amended to create the Lower Klamath Project, a new FERC project encompassing the four dams to be removed, and

(2) that the license for the Lower Klamath Project be transferred to the KRRC.

On the same date, the KRRC filed an application with FERC to surrender the license for the Lower Klamath Project and decommission the four dams.

FERC is now in the process of evaluating the application to amend and transfer the license for the Lower Klamath Project to the KRRC. Separately, the KRRC is developing more detailed plans for dam removal that are anticipated to be submitted to FERC by the end of 2017. KRRC is also seeking permits necessary for dam removal to proceed. PacifiCorp anticipates that FERC will rule on the application to amend the license and transfer the Lower Klamath Project to the KRRC by early 2018, and that dam removal may begin in 2020, consistent with the timeline anticipated in the KHSA.

DPU Data Request 2.10

Please provide a status report on the Deer Creek closure. Please provide start date for the closure, what percentage complete is the closure project at December 31, 2016, through December 31, 2016 the costs that have gone into closure by significant category and how does that compare to the budgeted closure costs and any other pertinent information. Please provide direct and indirect applicable account balances per inception showing yearly accounting entries with explanations through year-end 2016 and May 31, 2017.

Response to DPU Data Request 2.10

The closure process began shortly after the Deer Creek Mine transaction was closed on June 5, 2015, and is ongoing. Final completion of the closure process began on July 7, 2017, following receipt of all required approvals from the United States (U.S.) Bureau of Land Management (BLM), the US Forest Service, and the Utah Division of Oil, Gas and Mining. The Company anticipates completion of closure activities soon after the end of 2017.

As of December 31, 2016, approximately 76 percent of the currently forecasted closure costs had been incurred.

Please refer to Confidential Attachment DPU 2.10 -1 for a high level summary of actual and forecast closure costs by category, with comparisons (as of December 31, 2016 and May 31, 2017) to amounts included in the "Application for Approval of Transaction and For A Deferred Accounting Order" (Docket 14-035-147). The attachment also includes a tab, "Reg Assets-20170531", showing the regulatory asset account balances as of December 31, 2016 and May 31, 2017, which reflects activity since inception.

Please refer to Confidential Attachment DPU 2.10 -2 for the entries recorded following closing of the transaction in June 2015. As noted in the footnote of the file, monthly adjustments continue to be recorded to reflect closure costs as they are incurred, along with other monthly adjustments and true-ups. A similar analysis through year-end 2016, and May 31, 2017, has not been prepared.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules 746-1-602 and 603.