ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 310
Salt Lake City, Utah 84114

December 19, 2017

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: Docket No. 17-035-01 – Application of Rocky Mountain Power to Decrease the Deferred EBA Rate through the Energy Balancing Account Mechanism – Response Testimony

Rocky Mountain Power hereby submits its response to the audit report and direct testimony of the Utah Division of Public Utilities filed on November 15, 2017. As requested by the Commission, Rocky Mountain Power is also providing seven (7) printed copies of the filing via overnight delivery.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
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Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

cc: Service List

REDACTED
Rocky Mountain Power
Docket No. 17-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Response Testimony of Michael G. Wilding

December 2017

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

A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Q. Are you the same Michael G. Wilding who submitted direct testimony on behalf of the Company in this proceeding?

A. Yes.

Q. What is the purpose of your response testimony?

A. My testimony responds to certain issues raised by the Utah Division of Public Utilities ("DPU") in its energy balancing account ("EBA") Audit Report and by Daymark Energy Advisors ("Daymark"), on behalf of the DPU, in its Audit Report. Specifically, I address the replacement power costs calculated by Daymark for the proposed adjustment related to Gadsby Units 4–6 plant outages. The Company's position is that no adjustment for plant outages is warranted as the Company was prudent in its operations. However, if the Commission determines that an adjustment is needed, the calculation of replacement power costs for Gadsby Units 4–6 plant outages made by Daymark should be corrected. In addition, I address the DPU's request related to updating certain language in Tariff Schedule 94.

Q. Do any other Company witnesses also provide testimony in response to issues raised by the DPU and Daymark?

A. Yes. Company witness Mr. Dana M. Ralston provides testimony responding to the proposed adjustments related to plant outages and the Joy longwall. Mr. Ralston explains that the Company was prudent in its operations and management of its thermal generation plants and the Joy longwall.

REPLACEMENT POWER COSTS

Q. Please describe the proposed adjustment for plant outages.

A. Daymark recommends removing replacement power costs from the EBA for seven plant outages at Gadsby Units 4–6, which it claims were imprudent.

Q. Does the Company agree the replacement power for plant outages should be disallowed?

A. No. Company witness Mr. Ralston provides detailed testimony explaining the prudence of the identified plant outages.

Q. Does the Company agree with Daymark's calculation of the replacement power cost at the Gadsby Units 4-6?

A. No. To determine the cost of replacement power Daymark compared the hourly California Independent System Operator's ("CAISO") day-ahead market ("DAM") locational marginal prices ("LMP") to the generation costs. Generation costs are estimated based on average heat rates, natural-gas prices at the Opal index market, and $2.00/megawatt-hour ("MWh") for variable operations and maintenance ("VOM") costs. Any lost MWh was determined by dispatching the unit when generation costs were less than the hourly CAISO DAM LMP. To calculate the replacement power cost, Daymark multiplied lost MWh by the difference between the LMP and the marginal generation cost. While the Company agrees with the calculation methodology of replacement power costs, the Company does not agree with the inputs Daymark used.

Q. Which inputs did Daymark use that the Company disagrees with?

A. First, as Daymark itself noted, PacifiCorp does not participate in the CAISO DAM[1]; therefore, lost output should not be valued at a market in which the Company does not participate. It would be more appropriate to replace the CAISO DAM LMP with PowerDex hourly market prices at the 4-Corners market hub because PacifiCorp uses this market hub for the Gadsby plant. Second, the actual VOM costs should be used rather than the *estimated* VOM included by Daymark. The actual VOM costs for Gadsby Units 4–6 are $[redacted]/MWh, compared to Daymark's estimated VOM costs of $[redacted]/MWh. Lastly, Daymark should have used actual average heat rates rather than the estimated heat rate.

Q. Why is the CAISO DAM LMP not the appropriate price to determine plant dispatch?

A, Again, the Company does not participate in the CAISO DAM. In other words, the Company does not provide the CAISO with an accurate day-ahead schedule or day-ahead resource bids; therefore, the CAISO DAM cannot be relied upon. In addition, Gadsby Units 4–6 are not typically dispatched in the day-ahead but instead are dispatched within the day. Therefore using an hourly price, versus a day-ahead price, to determine replacement power costs is more appropriate. Table 1 below shows the percentage of hours each month in which the Gadsby Units 4–6 were dispatched in the day-ahead, and why it is inappropriate to use the CAISO DAM. The percentage of hours in the six months the Company used the CAISO DAM is less than one percent in each of those six months.

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[1] Daymark Exhibit 2.3, EBA Audit Report, Page 26.

Table 1

Month (2016)	Gadsby 4	Gadsby 5	Gadsby 6
Jan	0.03%	0.03%	0.03%
Feb			
Mar			
Apr	0.03%	0.03%	0.03%
May	0.01%	0.01%	0.01%
Jun	0.02%	0.02%	0.02%
Jul			
Aug	0.15%	0.11%	0.13%
Sep			
Oct			
Nov		0.08%	
Dec	0.55%	0.55%	0.55%

Q. Has the Company provided a corrected calculation of the replacement power costs?

A. Yes, workpapers containing the corrected calculation are provided with my testimony. Making the corrections noted above to the replacement power costs reduces the impact of the proposed adjustments to Utah-allocated net power costs from approximately $43,000 to approximately $9,400 before application of the sharing band, where applicable. However, as stated in Mr. Ralston's response testimony, the Company's position is that no adjustment should be made.

Q. Does the Company agree with the computation of other replacement power costs?

A. The methodology Daymark used to compute non-peaker replacement power costs is reasonable. However, the Company did note two instances where the first-day or last-day peak and off-peak outage hours were incorrectly calculated for Hermiston Unit 1 and Dave Johnston Unit 4. In addition, the outage hours related to Colstrip Unit 3 were not calculated correctly. The outage to repair the economizer tube leak lasted no more than 84 hours and the remainder of the 209 hours of this outage related to a boiler water pump issue. These were separate instances and the computation of replacement power should have only covered the period related to the economizer tube leak, which was 84 hours. Table 2 below shows the corrected replacement power costs for all contested outages on a total Company basis.

Table 2

Outage	Start Date	Proposed Replacement Power Costs	Corrected Replacement Power Costs	Difference
Colstrip 3	5/3/2016	$ 2,923	$ 1,274	$ (1,649)
Colstrip 4	10/27/2016	27,193	27,193	-
Dave Johnston 4	3/25/2016	117,482	117,201	(280)
Gadsby 4	3/30/2016	3,571	142	(3,429)
Gadsby 4	4/8/2016	2,525	2,316	(208)
Gadsby 5	3/30/2016	5,703	880	(4,823)
Gadsby 5	4/8/2016	2,145	2,077	(67)
Gadsby 6	3/30/2016	8,459	41	(8,418)
Gadsby 6	4/8/2016	1,573	18	(1,555)
Gadsby 6	7/19/2016	75,090	16,244	(58,846)
Hermiston 1	8/2/2016	79,387	80,835	1,448
Hermiston 1	9/18/2016	7,113	7,113	-
Naughton 2	5/28/2016	47,949	47,949	-
Naughton 2	6/6/2016	136,570	136,570	-
Total		**$ 517,681**	**$ 439,854**	**$ (77,827)**

Notably, the replacement energy from an outage is not necessarily only covered in full or part by market transactions. The Company's actual system operates dynamically, and therefore a unit's outage would change a number of system operational events, such as (but not limited to) ramping up / ramping down of other online generation units, utilizing contract rights, and market transactions.

TARIFF SCHEDULE 94

Q. Please explain the DPU's proposed language change in Tariff Schedule 94.

A. The DPU proposes revising Tariff Schedule 94 to reflect more precise language from the Commission's order in Docket No. 09-035-15 issued February 16, 2017,[2] which revised the EBA filing schedule ("Order"). Tariff Schedule No. 94 was included in this filing as Exhibit RMP___(RMM-3) with Mr. Robert M. Meredith's testimony on March 15, 2017. In accordance with the DPU's request, attached in Exhibit RMP___(MGW-1R) is a first revision of Tariff Schedule No. 94.3 – 94.10, updating the language consistent with the Order. This first revision includes the original modifications made by Mr. Meredith in his filed testimony as well as the DPU's request to use Commission language.

Q. Does this conclude your response testimony?

A. Yes.

[2] Utah Division of Public Utilities Exhibit 1.2, EBA Audit Report, Page 36.

Rocky Mountain Power
Exhibit RMP___(MGW-1R)
Docket No. 17-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Response Testimony of Michael G. Wilding
Proposed Revisions to Schedule 94

December 2017

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

Net Power Costs (NPC): the sum of costs incurred to acquire power to serve customers less revenues collected from sales for resale. NPC components are those included in the Company's production cost model and recorded in the FERC Accounts described in this electric service schedule.

Wheeling Revenue: Revenues from Transmission of Electricity of Others recorded in the FERC Account described in this electric service schedule.

EBA PROCEDURAL SCHEDULE (Beginning with the 2013 Annual EBA Filing)

1. Rocky Mountain Power will file its EBA application on or about March 15.
2. The Division of Public Utilities (DPU) will conduct a preliminary review of Rocky Mountain Power's application and provide a preliminary conclusion if the EBA filing appears to not depart from prior years' filings.
3. On or before May 1, the Public Service Commission of Utah (PSC) will approve interim rates with an amortization period through April of the following year, effective May 1.
4. The DPU will then file its audit report by November 15, following which the PSC will set a schedule in the docket.
5. The PSC will hold a hearing on or about February 1, after which a true-up of rates could be ordered.
6. The PSC will issue an order by March 1 of the following year before the next EBA filing is made.
7. Any true-up to interim rates will go into effect March 1, and be amortized through April 30 of the year following the year the application is filed.

EBA CALCULATIONS AND APPLICATION

APPLICABLE FERC ACCOUNTS: The EBA rate will be calculated using all components of EBAC as defined in the Company's most recent general rate case, major plant addition case, or other case where Base EBAC are approved. EBAC are typically booked to the following FERC accounts, as defined in Code of Federal Regulations, Subchapter C, Part 101, with the noted clarifications and exclusions:

<u>FERC 501- Fuel</u>

FERC Sub 5011000

SAP 515100 – Coal Consumed-Generation (Include)

SAP (all other) – Legal, maintenance, utilities, labor related, miscel O&M (Exclude)

FERC Sub 5013500 - Natural Gas Consumed (Non Gadsby) Natural Gas Swaps (Non Gadsby) (Include)

FERC Sub (All Other) – Property tax, office supplies, Labor, Fuel Handling, Supplies, Maintenance, Start-up Fuel,Start-up Fuel Diesel, Diesel Fuel Hedge, miscellaneous O&M, Flyash Sales (Exclude)

(continued)

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

EBA FERC 501 Adjustments

FERC Sub 5013500
SAP 515200 – Natural Gas Consumed
Gadsby Related Portion of 515200 is transferred to FERC 547(Fuel-Other Generation)
SAP 515220 – Natural Gas Swaps
Gadsby Related portion of 515220 is transferred to FERC 547(Fuel-Other Generation)
SAP 505917– I/C Nat Gas Cons Ker. This SAP account is transferred to FERC 547(Fuel-Other Generation)

FERC 447 – Sales For Resale

FERC Sub 4471400
SAP 301406 – Short-term Firm Wholesale
Non Transalta Sales (Include)
SAP 301409 – Trading Sales Netted-Estimate (Exclude)
SAP 301410 – Trade Sales Netted (Include)
SAP 301411 – Bookout Sales Netted (Include)
SAP 301412 – Bookout Sales Netted-Estimate (Exclude)
SAP 302751 – I/C ST Firm Whls-Sie (Include)
SAP 302752 – I/C S-T Firm Wholesale Sales-Nevada Pwr (Include)
SAP 302771 – I/C Line Loss Trading Revenue-Sierra Pac (Include)
SAP 302772 – I/C Line Loss-Nevada (Include)
SAP 303028 – Line Loss W/S Trading (Include)
SAP 303100 – Transmission Loss Charge Pass-Through (Exclude)
SAP 303109 – Transmission Line Loss Rev – Subject to Refund (Include)
SAP 301409 – Trading Sales Netted – Estimates (Exclude)
FERC Sub 4471300
SAP 301405 – FIRM Sales (Include)
FERC Sub 4476100
SAP 304101 – Bookouts Netted – Gain (Include)
SAP 304102 – Bookouts Netted – Estimates (Exclude)
FERC Sub 4476200
SAP 304201 – Trading Net- Gains (Include)
FERC Sub 4472000 – Sales for Resale Estimates (Exclude)
FERC Sub 4475000
SAP 301408 – Off-System Non Firm (Include)
FERC Sub 4479000 – Transmission Services - Utah FERC Customers, Wyo-Pacific Cheyenne (Exclude)
FERC Sub 4471000 – Onsystem Firm - Utah FERC Customers, Wyo-Pacific Cheyenne, Brigham City, Portland General Electric (Exclude)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

EBA FERC 447 Adjustments

1) SAP 301406 - Short-term Firm Wholesale – Transalta Sales are removed from 447 and transferred into 555 (Purchased Power).
2) SAP 505214 – SMUD Purchases from 555 (Purchased Power) are transferred to 447.

FERC 555 – Purchased Power

FERC Sub 5552600
SAP 505351 – Electric Swaps G/L (Include)
SAP 505352 – Electric Swaps G/L Estimate (Exclude)
FERC Sub 5551100,1200,1330 - BPA Residential Exchange (Exclude)

FERC 555 – Purchased Power (continued)

FERC Sub 5552200,2300,2400 – REC Purchases, RPS Compliance Purchases (Exclude)
FERC Sub 5552500
SAP 505190 – OR Solar Incentive Purchases (Include)
SAP 505206 – Other Energy Purchases, Int (Include)
SAP (All Other) – Exchange Value Purchase, Exchange Value Purchase – Estimate, Purchase Power Expense – Estimate, I/C Purchased Power Esp Est-Sierra Pac,I/C Purchased Power Exp Est-Nevada Pwr, Renewable Energy Credit Purchase (Exclude)
FERC Sub 5555500
SAP 505207 – IPP Energy Purchase (Include)
FERC Sub 5556200
SAP 304211 – Trading Netted – Loss (Include)
SAP 304213 – Trading Netted – Estimates (Exclude)
FERC Sub 5556300
SAP 505214 – Firm Energy Purchases (Include)
FERC Sub 5556400
SAP 505218 – Firm Demand Purchases (Include)
FERC Sub 5555700, 5556700
SAP 505215 – Post Merger Imb Charge (Include)
SAP 505220 – Trading Purchases Netted (Include)
SAP 505221 – Bookout Purchases Netted (Include)
SAP 505969 – Transmission Imbalance – Subject to Refund (Include)
SAP 546516 – CA GHG Wholesale Obligation (Include)
SAP 546520 – Operating Reserves Expense (Include)
SAP (All Other) – Bookout Purchases Net – Estimates, Trading Purchases Netted – Estimates, Transmission Imblance Pass-Through Expense, NPC Deferral Accounting Entries, Excess Net Power Cost Amortization Renewable Energy Credit Sales Deferral CA GHG Allowance Amortization Expense (Exclude)
FERC Sub 5556710
SAP 508001 - EIM Exp - FMM IIE: CAISO to Pac (Include)
SAP 508003 - EIM Exp - FMM Assess: Pac Trans to C&T (Include)
SAP 508011 - EIM Exp - RTD IIE: CAISO to Pac (Include)
SAP 508013 - EIM Exp - RTD Assess: Pac Trans to C&T (Include)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

FERC 555 – Purchased Power (continued)

FERC Sub 5556710 (continued)

SAP 508015 - EIM Exp - GHG Em Cost Rev: CAISO to Pac (Include)
SAP 508021 - EIM Exp - UIE (Load): CAISO to Pac (Include)
SAP 508023 - EIM Exp - UIE (Load): Pac Trans to C&T (Include)
SAP 508031 - EIM Exp - UIE (Gen): CAISO to Pac (Include)
SAP 508033 - EIM Exp - UIE (Gen): Pac Trans to C&T (Include)
SAP 508041 - EIM Exp - Daily Rounding Adj: w/CAISO (Include)
SAP 508051 - EIM Exp - O/U Sched Charge: w/CAISO (Include)
SAP 508052 - EIM Exp – EIM Exp - O/U Sched Alloc: w/CAISO (Include)
SAP 508053 - EIM Exp - O/U Sched Alloc: w/CAISO (Include)
SAP 508054 - EIM Exp - O/U Sched Alloc: PAC to TC (Include)
SAP 508061 - EIM Exp-Ancil Svc Upw Neutral: w/CAISO (Include)
SAP 508062 - EIM Exp-Spinning Reserve Oblig: w/CAISO (Include)
SAP 508063 - EIM Exp-Spin Reserve Neutral: w/CAISO (Include)
SAP 508064 - EIM Exp-Non-Spin Reserve Oblig: w/CAISO (Inlcude)
SAP 508065 - EIM Exp-Non-Spin Reserve Neut: w/CAISO (Inlcude)
SAP 508066 - EIM Exp - Excess Cost Neutral: w/CAISO (Include)
SAP 508071 - EIM Exp - RT Bid Cost Recovery: w/CAISO (Include)
SAP 508081 - EIM Exp-IFM Loss Surplus Credit w/CAISO (Include)
SAP 508091 - EIM Exp - Flexible Ramp Cost: w/CAISO (Include)
SAP 508092 - EIM Exp - Flexible Ramp Cost (Include)
SAP 508095 - EIM Exp-Flex RampUp Cap Pay: w/CAISO (Include)
SAP 508096 - EIM Exp-Flex RampUp Cap No Pay: w/CAISO (Include)
SAP 508101 - EIM Exp-RT Unaccounted Energy: w/CAISO (Include)
SAP 508111 - EIM Exp-RT Imb Energy Offset: w/CAISO (Include)
SAP 508112 - EIM Exp-RT Imb Energy Offset (Include)
SAP 508121 - EIM Exp-RT BCR EIM Alloc: CAISO to Pac (Include)
SAP 508122 - EIM Exp-RT BCR EIM (Include)
SAP 508125 - EIM Exp-RTM BCR EIM Set: CAISO to Pac (Include)
SAP 508131 - EIM Exp-RT Congestion OS: CAISO to Pac (Include)
SAP 508132 - EIM Exp-RT Congestion (Include)
SAP 508141 - EIM Exp-RT Marginal Loss: CAISO to Pac (Include)
SAP 508142 - EIM Exp-Neutrality Adjust CAISO to Pac (Include)
SAP 508151 - EIM Exp-7070 FRP Forecast Mvmt
SAP 508152 - EIM Exp-7076 FRP Forecast Mvmt Alloc
SAP 508153 - EIM Exp-7071 FRP Daily Up Uncert
SAP 508154 - EIM Exp-7081 FRP Daily Down Uncert
SAP 508155 - EIM Exp-7077 FRP Daily Up Uncert Alloc
SAP 508156 - EIM Exp-7078 FRP Month Up Uncert Alloc
SAP 508157 - EIM Exp-7087 FRP Daily Down Uncert Allo
SAP 508158 - EIM Exp-7088 FRP Month Down Uncert Allo

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ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

FERC 555 – Purchased Power (continued)
FERC Sub 5558000
SAP 505227 – Purchased Power Expense – Under Capital Lease (Include)
FERC Sub 5556100
SAP 304111 – Bookouts Netted – Loss (Include)
FERC Sub 5555900
SAP 505224 – Short-Term Firm Wholesale Purchases (Include)
SAP 505931 – I/C ST Firm Pur-Sier (Include)
SAP 505932 – I/C ST Firm Pur-Nev (Include)

EBA FERC 555 Adjustments
1) FERC Sub 5552500
SAP 505206 - Other Energy Purchases: Remove exchange dollars
2) SAP 301406 - Short-term Firm Wholesale – Transalta Sales are removed from 447 and transferred into 555 (Purchased Power).
3) SAP 505214 - SMUD Purchases are removed from 555 (Purchased Power) and transferred to 447.

FERC 565 – Wheeling Expense
FERC Sub 5650000
SAP 546530 - ISO/PX Charges (Include)
FERC Sub 5650010
SAP 506801 - EIM Wheeling Exp-GMC (Include)
SAP 506802 - EIM Wheeling Exp-GMC (Include)
FERC Sub 5651000
SAP 506010 - Short Term Firm Wheeling (Include)
SAP 506059 - Wheeling Expense Estimate (Exclude)
SAP 506911 - I/C S-T Firm Wheeling Exp-Nevada Pwr (Include)
SAP 506912 - I/C S-T Firm Wheeling Exp-Nevada Pwr (Include)
SAP 506952 - I/C Wheeling Exp Estimate-Nevada Pwr (Exclude)
FERC Sub 5652500, 5654600
SAP 506921 - I/C Non-Firm Wheeling Exp-Sierra Pac (Include)
SAP 506922 – I/C Non-Firm Wheeling Exp-Nevada Pwr (Include)

FERC 503 Steam From Other Sources
FERC Sub 5030000
SAP 515900 – Geothermal Steam (Include)
SAP (All Other) – Labor, materials and supplies, other miscellaneous O&M (Exclude)

(continued)

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

FERC 547 Fuel – Other Generation

FERC Sub 5471000 - I/C Nat Gas Cons Ker, Natural Gas Consumed, Nat Gas Exp – Under Capital Lease, Natural Gas Swaps (Include)

EBA FERC 547 Adjustments

FERC Sub 5013500

SAP 515200 – Natural Gas Consumed

Gadsby Related Portion of 515200 (From FERC 501) is transferred to this FERC account (547).

SAP 515220 – Natural Gas Swaps

Gadsby Related portion of 515220 (From FERC 501) is transferred to this FERC account (547).

SAP 505917 - I/C Nat Gas Cons Ker. Some of this SAP account was booked originally to FERC 501. This adjustment transfers the amount in 501 to this FERC account (547).

FERC 456.1 Revenues from Transmission of Electricity by Others

FERC Sub 4561100

SAP 505961 – Transmission Imbalance Penalty Revenue – Load (Exclude)
SAP 505963 – Transmission Imbalance Penalty Revenue –Pt to Pt (Exclude)
SAP (All Other) – Primary Delivery and Distribution Sub Charges, Ancillary Revenue, Use of Facility – Revenue, Transmission Resales to Other Parties, Transmission Revenue Unreserved Use Charges Transmission Revenue – Deferral Fees (Include)
SAP 302081 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)
SAP 302082 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)
SAP 302091 - I/C Anc Rev Sch 2-Reactive-Sierra Pac (Include)
SAP 302092 - I/C Anc Rev Sch 2-Reactive-Nevada Pwr (Include)
SAP 302821 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)
SAP 302822 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)
SAP 302831 – I/C Other Wheeling Revenue-Sierra Pac (Include)

FERC Sub 4561600

SAP 301912 – Post-Merger Firm Wheeling Revenue (Include)

FERC Sub 4561910

SAP 301926 – Short-Term Firm Wheeling (Include)
SAP 302812 - I/C ST Firm Wheeling Revenue-Nevada Pwr (Include)

FERC Sub 4561920 – Firm Wheeling Revenue, Pre-Merger Firm Wheeling Revenue, Transmission Capacity Re-assignment revenue and contra revenue, Transmission Point-to-Point Revenue (Include)

FERC Sub 4561930

SAP 301922 – Non-Firm Wheeling Revenue (Include)

FERC Sub 4561990

SAP 301913 – Transmission Tariff True-up (Include)
SAP 302990 – L-T Transmission Revenue – Subject to Refund (Include)
SAP 302991 – S-T Transmission Revenue – Subject to Refund (Include)

(continued)

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

FERC 456.1 Revenues from Transmission of Electricity by Others (continued)

FERC Sub 4561990 (continued)

SAP 305910 – Ancillary Revenue Sch 1 – Subject to Refund (Include)
SAP 305920 – Ancillary Revenue Sch 2 – Subject to Refund (Include)
SAP 305930 – Ancillary Revenue Sch 3 – Subject to Refund (Include)
SAP 305931 – Ancillary Revenue Sch 3a – Subject to Refund (Include)

Accruals or estimates in accounts 447, 555, and 565 will be excluded; rather, expenses and revenue will be accounted for in the months that they are incurred. Adjustments shall be made to Actual EBAC that are consistent with Commission accepted or ordered adjustments, or adjustments called out in a stipulation or settlement agreement, as ordered in the most recent general rate case, major plant addition case, or other case where Base EBAC are approved.

EBA DEFERRAL: The monthly EBA Accrual (positive or negative) is determined by calculating the difference between Base NPC and Actual NPC as is described below.

Through May 31, 2016:

$$\textit{EBA Deferral}_{\textit{Utah, month}} = [(\textit{Actual EBAC}_{\textit{month/MWh}} - \textit{Base EBAC}_{\textit{month/MWh}}) \times \textit{Actual MWH}_{\textit{Utah,, month}}] \times 70\%$$

Starting June 1, 2016 through December 31, 2019:

$$\textit{EBA Deferral}_{\textit{Utah, month}} = [(\textit{Actual EBAC}_{\textit{month/MWh}} - \textit{Base EBAC}_{\textit{month/MWh}}) \times \textit{Actual MWH}_{\textit{Utah,, month}}] \times 100\%$$

Where:

$$\textit{Actual EBAC}_{\textit{month/MWh}} = (\textit{NPC}_{\textit{Utah, month, actual}} / \textit{Actual MWh}_{\textit{Utah, month}}) + (\textit{WR}_{\textit{Utah, month, actual}} / \textit{Actual MWh}_{\textit{Utah, month}})$$

$$\textit{Base EBAC}_{\textit{month/MWh}} = (\textit{NPC}_{\textit{Utah, month base}} / \textit{Base MWh}_{\textit{Utah, month}}) + (\textit{WR}_{\textit{Utah, month, base}} / \textit{Base MWh}_{\textit{Utah, month}})$$

$\text{NPC}_{\text{Utah, month}}$ = Total Company NPC for the month multiplied by the appropriate allocation factors from the most recent general rate case, major plant additions case, or other case where Base EBAC are approved.

$\text{WR}_{\text{Utah, month}}$ = Total Company Wheeling Revenue for the month multiplied by the appropriate allocation factors from the most recent general rate case, major plant additions case, or other case where Base EBAC are approved.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

EBA Deferral Account Balance: the monthly EBA Account Balance will be calculated as follows:

$$\textit{EBA Deferral Account Balance}_{\text{current month}} = \textit{Ending Balance}_{\text{previous month}} + \textit{Deferral}_{\text{current month}} - \textit{EBA Revenue}_{\text{current month}} + \textit{EBA Carrying charge}_{\text{month}}$$

EBA CARRYING CHARGE: the EBA Carrying Charge will be calculated and applied to the monthly balance in the EBA Deferral Account as follows:

$$\textit{EBA Carrying Charge}_{\text{month}} = [\textit{Ending Balance}_{\text{previous month}} + (\textit{Deferral}_{\text{current month}} \times 0.5) - (\textit{EBA Revenue}_{\text{current month}} \times 0.5)] \times 0.5\%$$

EBA RATE DETERMINATION: Annually, on the EBA Filing Date, Rocky Mountain Power shall file with the Commission an application for establishment of an EBA rate to become effective on the EBA Rate Effective Date of that year. The EBA Deferral Account Balance as of December 31 shall be allocated to all retail tariff rate schedules and applicable special contracts based on the rate spread approved by the Commission. The new EBA rate will be determined by dividing the EBA Deferral Account Balance allocated to each rate schedule and applicable contract by the schedule or contract forecasted Power Charge and Energy Charge revenues. The EBA rate will be a percentage increase or decrease applied to the monthly Power Charges and Energy Charges of the Customer's applicable schedule or contract as set forth in the schedule.

AUDIT PROCEDURES: All items recorded in the EBA Balancing Account are subject to regulatory audit and prudence review. The Division of Public Utilities will complete its audit according to the EBA Procedural Schedule.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

Net Power Costs (NPC): the sum of costs incurred to acquire power to serve customers less revenues collected from sales for resale. NPC components are those included in the Company's production cost model and recorded in the FERC Accounts described in this electric service schedule.

Wheeling Revenue: Revenues from Transmission of Electricity of Others recorded in the FERC Account described in this electric service schedule.

EBA PROCEDURAL SCHEDULE (Beginning with the 2013 Annual EBA Filing)

1. Rocky Mountain Power will file its EBA application on or about March 15.
2. The Division of Public Utilities (DPU) will conduct a preliminary review of Rocky Mountain Power's application and provide a preliminary conclusion if the EBA filing appears to not depart from prior years' filings.
3. ~~1.~~3.On or before May 1, the Public Service Commission of Utah (PSC) will approve interim rates with an amortization period through April of the following year, effective May 1.
4. ~~2.~~4.The ~~Division of Public Utilities~~DPU will then file ~~complete~~ its audit report ~~and supporting testimony~~ by ~~July~~ November 15, following which the PSC will set a schedule in the docket.
5. ~~3.~~5.The PSC will hold a hearing on or about February 1, after which a true-up of rates could be ordered~~Intervenors may conduct discovery, with a 14 day turn around, beginning March 15~~.
6. ~~4.~~6.The PSC will issue an order by March 1 of the following year before the next EBA filing is made~~Hearings on the application will be completed by September 15~~.
7. ~~5.~~7.Any true-up to interim rates ~~change necessary to recover or refund an EBA balance~~ will ~~take~~ go into effect March 1, and be amortized through April 30~~on or before November 1~~ of the year following the year the application is filed.

EBA CALCULATIONS AND APPLICATION

APPLICABLE FERC ACCOUNTS: The EBA rate will be calculated using all components of EBAC as defined in the Company's most recent general rate case, major plant addition case, or other case where Base EBAC are approved. EBAC are typically booked to the following FERC accounts, as defined in Code of Federal Regulations, Subchapter C, Part 101, with the noted clarifications and exclusions:

FERC 501- Fuel

FERC Sub 5011000

SAP 515100 – Coal Consumed-Generation (Include)

SAP (all other) – ~~-~~Legal, maintenance, utilities, labor related, miscel O&M (Exclude)

FERC Sub 5013500 - Natural Gas Consumed (Non Gadsby) ~~-~~Natural Gas Swaps (Non Gadsby) (Include)

(continued)

FERC Sub (All Other)~~-~~ – Property tax, office supplies, Labor, Fuel Handling, Supplies, Maintenance, Start-up Fuel,
Start-up Fuel Diesel, Diesel Fuel Hedge, miscellaneous O&M, Flyash Sales (Exclude)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

EBA FERC 501 Adjustments

FERC Sub 5013500
SAP 515200 – Natural Gas Consumed
Gadsby Related Portion of 515200 is transferred to FERC 547(Fuel-Other Generation)
SAP 515220 – Natural Gas Swaps
Gadsby Related portion of 515220 is transferred to FERC 547(Fuel-Other Generation)
SAP 505917– I/C Nat Gas Cons Ker. This SAP account is transferred to FERC 547(Fuel-Other Generation)

FERC 447 – Sales For Resale

FERC Sub 4471400
SAP 301406 – Short-term Firm Wholesale
Non Transalta Sales (Include)
SAP 301409 – Trading Sales Netted-Estimate (Exclude)
SAP 301410 – Trade Sales Netted (Include)
SAP 301411 – Bookout Sales Netted (Include)
SAP 301412 – Bookout Sales Netted-Estimate (Exclude)
SAP 302751 – I/C ST Firm Whls-Sie (Include)
SAP 302752 – I/C S-T Firm Wholesale Sales-Nevada Pwr (Include)
SAP 302771 – I/C Line Loss Trading Revenue-Sierra Pac (Include)
SAP 302772 – I/C Line Loss-Nevada (Include)
SAP 303028 – Line Loss W/S Trading (Include)
SAP 303100 – Transmission Loss Charge Pass-Through (Exclude)
SAP 303109 – Transmission Line Loss Rev – Subject to Refund (Include)
SAP 301409 – Trading Sales Netted – Estimates (Exclude)
FERC Sub 4471300
SAP 301405 – FIRM Sales (Include)
FERC Sub 4476100
SAP 304101 – Bookouts Netted – Gain (Include)
SAP 304102 – Bookouts Netted – Estimates (Exclude)
FERC Sub 4476200
SAP 304201 – Trading Net- Gains (Include)
FERC Sub 4472000 – Sales for Resale Estimates (Exclude)
FERC Sub 4475000
SAP 301408 – Off-System Non Firm (Include)
FERC Sub 4479000 – Transmission Services - Utah FERC Customers, Wyo-Pacific Cheyenne (Exclude)
FERC Sub 4471000 – Onsystem Firm - Utah FERC Customers, Wyo-Pacific Cheyenne, Brigham City, Portland General Electric (Exclude)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

EBA FERC 447 Adjustments

1) SAP 301406 - Short-term Firm Wholesale – Transalta Sales are removed from 447 and transferred into 555 (Purchased Power).
2) SAP 505214 – SMUD Purchases from 555 (Purchased Power) are transferred to 447.

FERC 555 – Purchased Power

FERC Sub 5552600
SAP 505351 – Electric Swaps G/L (Include)
SAP 505352 – Electric Swaps G/L Estimate (Exclude)
FERC Sub 5551100,1200,1330 - BPA Residential Exchange (Exclude)

FERC 555 – Purchased Power (continued)

FERC Sub 5552200,2300,2400 – REC Purchases, RPS Compliance Purchases (Exclude)
FERC Sub 5552500
SAP 505190 – OR Solar Incentive Purchases (Include)
SAP 505206 – Other Energy Purchases, Int (Include)
SAP (All Other) – Exchange Value Purchase, Exchange Value Purchase – Estimate, Purchase Power Expense – Estimate, I/C Purchased Power Esp Est-Sierra Pac,I/C Purchased Power Exp Est-Nevada Pwr, Renewable Energy Credit Purchase (Exclude)
FERC Sub 5555500
SAP 505207 – -IPP Energy Purchase (Include)
FERC Sub 5556200
SAP 304211 – -Trading Netted – Loss (Include)
SAP 304213 – -Trading Netted – Estimates (Exclude)
FERC Sub 5556300
SAP 505214 – -Firm Energy Purchases (Include)
FERC Sub 5556400
SAP 505218 – -Firm Demand Purchases (Include)
FERC Sub 5555700, 5556700
SAP 505215 – Post Merger Imb Charge (Include)
SAP 505220 – Trading Purchases Netted (Include)
SAP 505221 – Bookout Purchases Netted (Include)
SAP 505969 – Transmission Imbalance – Subject to Refund (Include)
SAP 546516 – CA GHG Wholesale Obligation (Include)
SAP 546520 – Operating Reserves Expense (Include)
~~SAP 505969 – Transmission Imbalance – Subject to Refund (Include)~~
SAP (All Other) – Bookout Purchases Net – Estimates, Trading Purchases Netted – Estimates, Transmission Imblance Pass-Through Expense, NPC Deferral Accounting Entries, Excess Net Power Cost Amortization Renewable Energy Credit Sales Deferral CA GHG Allowance Amortization Expense (Exclude)
FERC Sub 5556710
SAP 508001 - EIM Exp - FMM IIE: CAISO to Pac (Include)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

SAP 508003 - EIM Exp - FMM Assess: Pac Trans to C&T (Include)
SAP 508011 - EIM Exp - RTD IIE: CAISO to Pac (Include)
SAP 508013 - EIM Exp - RTD Assess: Pac Trans to C&T (Include)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~Second~~ Third Revision of Sheet No. 94.6
P.S.C.U. No. 50 **Canceling ~~First~~ Second Revision of Sheet No. 94.6**

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

FERC 555 – Purchased Power (continued)

FERC Sub 5556710 (continued)

SAP 508015 - EIM Exp - GHG Em Cost Rev: CAISO to Pac (Include)
SAP 508021 - EIM Exp - UIE (Load): CAISO to Pac (Include)
SAP 508023 - EIM Exp - UIE (Load): Pac Trans to C&T (Include)
SAP 508031 - EIM Exp - UIE (Gen): CAISO to Pac (Include)
SAP 508033 - EIM Exp - UIE (Gen): Pac Trans to C&T (Include)
SAP 508041 - EIM Exp - Daily Rounding Adj: w/CAISO (Include)
SAP 508051 - EIM Exp - O/U Sched Charge: w/CAISO (Include)
SAP 508052 - EIM Exp – EIM Exp - O/U Sched Alloc: w/CAISO (Include)
SAP 508053 - EIM Exp - O/U Sched Alloc: w/CAISO (Include)
SAP 508054 - EIM Exp - O/U Sched Alloc: PAC to TC (Include)
SAP 508061 - EIM Exp-Ancil Svc Upw Neutral: w/CAISO (Include)
SAP 508062 - EIM Exp-Spinning Reserve Oblig: w/CAISO (Include)
SAP 508063 - EIM Exp-Spin Reserve Neutral: w/CAISO (Include)
SAP 508064 - EIM Exp-Non-Spin Reserve Oblig: w/CAISO (Inlcude)
SAP 508065 - EIM Exp-Non-Spin Reserve Neut: w/CAISO (Inlcude)
SAP 508066 - EIM Exp - Excess Cost Neutral: w/CAISO (Include)
SAP 508071 - EIM Exp - RT Bid Cost Recovery: w/CAISO (Include)
SAP 508081 - EIM Exp-IFM Loss Surplus Credit w/CAISO (Include)
SAP 508091 - EIM Exp - Flexible Ramp Cost: w/CAISO (Include)
SAP 508092 - EIM Exp - Flexible Ramp Cost (Include)
SAP 508095 - EIM Exp-Flex RampUp Cap Pay: w/CAISO (Include)
SAP 508096 - EIM Exp-Flex RampUp Cap No Pay: w/CAISO (Include)
SAP 508101 - EIM Exp-RT Unaccounted Energy: w/CAISO (Include)
SAP 508111 - EIM Exp-RT Imb Energy Offset: w/CAISO (Include)
SAP 508112 - EIM Exp-RT Imb Energy Offset (Include)
SAP 508121 - EIM Exp-RT BCR EIM Alloc: CAISO to Pac (Include)
SAP 508122 - EIM Exp-RT BCR EIM (Include)
SAP 508125 - EIM Exp-RTM BCR EIM Set: CAISO to Pac (Include)
SAP 508131 - EIM Exp-RT Congestion OS: CAISO to Pac (Include)
SAP 508132 - EIM Exp-RT Congestion (Include)
SAP 508141 - EIM Exp-RT Marginal Loss: CAISO to Pac (Include)
SAP 508142 - EIM Exp-Neutrality Adjust CAISO to Pac (Include)
SAP 508151 - EIM Exp-7070 FRP Forecast Mvmt
SAP 508152 - EIM Exp-7076 FRP Forecast Mvmt Alloc
SAP 508153 - EIM Exp-7071 FRP Daily Up Uncert
SAP 508154 - EIM Exp-7081 FRP Daily Down Uncert
SAP 508155 - EIM Exp-7077 FRP Daily Up Uncert Alloc
SAP 508156 - EIM Exp-7078 FRP Month Up Uncert Alloc
SAP 508157 - EIM Exp-7087 FRP Daily Down Uncert Allo
SAP 508158 - EIM Exp-7088 FRP Month Down Uncert Allo

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~Third~~ Fourth Revision of Sheet No. 94.7
P.S.C.U. No. 50 **Canceling ~~Second~~ Third Revision of Sheet No. 94.7**

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

FERC 555 – Purchased Power (continued)
FERC Sub 5558000
SAP 505227 – Purchased Power Expense – Under Capital Lease (~~Exclude~~Include)
FERC Sub 5556100
SAP 304111 – Bookouts Netted – Loss (Include)
FERC Sub 5555900
SAP 505224 – Short-Term Firm Wholesale Purchases (Include)
SAP 505931 – I/C ST Firm Pur-Sier (Include)
SAP 505932 – I/C ST Firm Pur-Nev (Include)

EBA FERC 555 Adjustments
1) FERC Sub 5552500
SAP 505206 - Other Energy Purchases: Remove exchange dollars
2) SAP 301406 - Short-term Firm Wholesale – Transalta Sales are removed from 447 and transferred into 555 (Purchased Power).
3) SAP 505214 - SMUD Purchases are removed from 555 (Purchased Power) and transferred to 447.

FERC 565 – Wheeling Expense ~~(continued)~~
FERC Sub 5650000
SAP 546530 - ISO/PX Charges (Include)
FERC Sub 5650010
SAP 506801 - EIM Wheeling Exp-GMC (Include)
SAP 506802 - EIM Wheeling Exp-GMC (Include)
FERC Sub 5651000
SAP 506010 - Short Term Firm Wheeling (Include)
SAP 506059 - Wheeling Expense Estimate (Exclude)
SAP 506911 - I/C S-T Firm Wheeling Exp-Nevada Pwr (Include)
SAP 506912 - I/C S-T Firm Wheeling Exp-Nevada Pwr (Include)
SAP 506952 - I/C Wheeling Exp Estimate-Nevada Pwr (Exclude)
FERC Sub 5652500~~,2700~~, 5654600~~– Non-Firm Wheeling Expense, Pre-Merger Firm Wheeling, Firm Wheeling Expense~~
~~Firm Wheeling Expense (Trm) (Include)~~
SAP 506921 - I/C Non-Firm Wheeling Exp-Sierra Pac (Include)
SAP 506922 – I/C Non-Firm Wheeling Exp-Nevada Pwr (Include)

FERC 503 Steam From Other Sources
FERC Sub 5030000
SAP 515900 – Geothermal Steam (Include)
SAP (All Other) – Labor, materials and supplies, other miscellaneous O&M (Exclude)

(continued)

Issued by authority of Report and Order of the Public Service Commission of Utah in Docket No. 17~~6~~-035-01

FILED: ~~October 11, 2016~~December 19, 2017
EFFECTIVE: ~~November 1, 2016~~May 1, 2017

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

FERC 547 Fuel – Other Generation

FERC Sub 5471000 - I/C Nat Gas Cons Ker, Natural Gas Consumed, Nat Gas Exp – Under Capital Lease, Natural Gas Swaps (Include)

EBA FERC 547 Adjustments

FERC Sub 5013500

SAP 515200 – Natural Gas Consumed

Gadsby Related Portion of 515200 (From FERC 501) is transferred to this FERC account (547).

SAP 515220 – Natural Gas Swaps

Gadsby Related portion of 515220 (From FERC 501) is transferred to this FERC account (547).

SAP 505917 - I/C Nat Gas Cons Ker. Some of this SAP account was booked originally to FERC 501. This adjustment transfers the amount in 501 to this FERC account (547).

FERC 456.1 Revenues from Transmission of Electricity by Others ~~(continued)~~

FERC Sub 4561100

SAP 505961 – Transmission Imbalance Penalty Revenue – Load (Exclude)

SAP 505963 – Transmission Imbalance Penalty Revenue –Pt to Pt (Exclude)

SAP (All Other) – Primary Delivery and Distribution Sub Charges, Ancillary Revenue, Use of Facility – Revenue, Transmission Resales to Other Parties, Transmission Revenue Unreserved Use Charges Transmission Revenue – Deferral Fees (Include)

SAP 302081 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)

SAP 302082 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)

SAP 302091 - I/C Anc Rev Sch 2-Reactive-Sierra Pac (Include)

SAP 302092 - I/C Anc Rev Sch 2-Reactive-Nevada Pwr (Include)

SAP 302821 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)

SAP 302822 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)

SAP 302831 – I/C Other Wheeling Revenue-Sierra Pac (Include)

FERC Sub 4561600

SAP 301912 – Post-Merger Firm Wheeling Revenue (Include)

FERC Sub 4561910

SAP 301926 – Short-Term Firm Wheeling (Include)

SAP 302812 - I/C ST Firm Wheeling Revenue-Nevada Pwr (Include)

FERC Sub 4561920 – Firm Wheeling Revenue, Pre-Merger Firm Wheeling Revenue, Transmission Capacity Re-assignment revenue and contra revenue, Transmission Point-to-Point Revenue (Include)

FERC Sub 4561930

SAP 301922 – Non-Firm Wheeling Revenue (Include)

FERC Sub 4561990

SAP 301913 – Transmission Tariff True-up (Include)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~Second~~ Third Revision of Sheet No. 94.8
P.S.C.U. No. 50 **Canceling ~~First~~ Second Revision of Sheet No. 94.8**

SAP 302990 – L-T Transmission Revenue – Subject to Refund (Include)
SAP 302991 – S-T Transmission Revenue – Subject to Refund (Include)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

FERC 456.1 Revenues from Transmission of Electricity by Others (continued)

FERC Sub 4561990 (continued)

SAP 305910 – Ancillary Revenue Sch 1 – Subject to Refund (Include)
SAP 305920 – Ancillary Revenue Sch 2 – Subject to Refund (Include)
SAP 305930 – Ancillary Revenue Sch 3 – Subject to Refund (Include)
SAP 305931 – Ancillary Revenue Sch 3a – Subject to Refund (Include)

Accruals or estimates in accounts 447, 555, and 565 will be excluded; rather, expenses and revenue will be accounted for in the months that they are incurred. Adjustments shall be made to Actual EBAC that are consistent with Commission accepted or ordered adjustments, or adjustments called out in a stipulation or settlement agreement, as ordered in the most recent general rate case, major plant addition case, or other case where Base EBAC are approved.

EBA DEFERRAL: The monthly EBA Accrual (positive or negative) is determined by calculating the difference between Base NPC and Actual NPC as is described below.

Through May 31, 2016:

$$\textit{EBA Deferral}_{\textit{Utah, month}} = [(\textit{Actual EBAC}_{\textit{month/MWh}} - \textit{Base EBAC}_{\textit{month/MWh}}) \times \textit{Actual MWH}_{\textit{Utah,, month}}] \times 70\%$$

Starting June 1, 2016 through December 31, 2019:

$$\textit{EBA Deferral}_{\textit{Utah, month}} = [(\textit{Actual EBAC}_{\textit{month/MWh}} - \textit{Base EBAC}_{\textit{month/MWh}}) \times \textit{Actual MWH}_{\textit{Utah,, month}}] \times 100\%$$

Where:

$$\textit{Actual EBAC}_{\textit{month/MWh}} = (\textit{NPC}_{\textit{Utah, month, actual}} / \textit{Actual MWh}_{\textit{Utah, month}}) + (\textit{WR}_{\textit{Utah, month, actual}} / \textit{Actual MWh}_{\textit{Utah, month}})$$

$$\textit{Base EBAC}_{\textit{month/MWh}} = (\textit{NPC}_{\textit{Utah, month base}} / \textit{Base MWh}_{\textit{Utah, month}}) + (\textit{WR}_{\textit{Utah, month, base}} / \textit{Base MWh}_{\textit{Utah, month}})$$

$\text{NPC}_{\text{Utah, month}}$ = Total Company NPC for the month multiplied by the appropriate allocation factors from the most recent general rate case, major plant additions case, or other case where Base EBAC are approved.

$\text{WR}_{\text{Utah, month}}$ = Total Company Wheeling Revenue for the month multiplied by the appropriate allocation factors from the most recent general rate case, major plant additions case, or other case where Base EBAC are approved.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – ~~c~~Continued

EBA Deferral Account Balance: the monthly EBA Account Balance will be calculated as follows:

$$EBA\ Deferral\ Account\ Balance_{\ current\ month} = Ending\ Balance_{\ previous\ month} + Deferral_{\ current\ month} - EBA\ Revenue_{\ current\ month} + EBA\ Carrying\ charge_{\ month}$$

EBA CARRYING CHARGE: the EBA Carrying Charge will be calculated and applied to the monthly balance in the EBA Deferral Account as follows:

$$EBA\ Carrying\ Charge_{\ month} = [Ending\ Balance_{\ previous\ month} + (Deferral_{\ current\ month} \times 0.5) - (EBA\ Revenue_{\ current\ month} \times 0.5)] \times 0.5\%$$

EBA RATE DETERMINATION: Annually, on the EBA Filing Date, Rocky Mountain Power shall file with the Commission an application for establishment of an EBA rate to become effective on the EBA Rate Effective Date of that year. The EBA Deferral Account Balance as of December 31 shall be allocated to all retail tariff rate schedules and applicable special contracts based on the rate spread approved by the Commission. The new EBA rate will be determined by dividing the EBA Deferral Account Balance allocated to each rate schedule and applicable contract by the schedule or contract forecasted Power Charge and Energy Charge revenues. The EBA rate will be a percentage increase or decrease applied to the monthly Power Charges and Energy Charges of the Customer's applicable schedule or contract as set forth in the schedule.

AUDIT PROCEDURES: All items recorded in the EBA Balancing Account are subject to regulatory audit and prudence review. The Division of Public Utilities will complete its audit according to the EBA Procedural Schedule.

(continued)

REDACTED
Rocky Mountain Power
Docket No. 17-035-01
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Response Testimony of Dana M. Ralston

December 2017

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("the Company").

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Senior Vice President of Thermal Generation and Mining.

Q. Mr. Ralston, have you previously submitted direct testimony on behalf of Rocky Mountain Power in this proceeding?

A. No.

Q. What is the purpose of your response testimony in this proceeding?

A. I respond to the direct testimony of Mr. Philip DiDomenico and Mr. Dan F. Koehler of Daymark Energy Advisors, Inc. ("Daymark") and the Technical Report on the Energy Balancing Account ("EBA") Audit for Rocky Mountain Power for Calendar Year 2016, filed on behalf of the Division of Public Utilities of the State of Utah ("DPU"). Specifically, I explain why the purchase of the Joy longwall by Bridger Coal Company ("BCC") was prudent and how acquisition of the longwall was expected to benefit BCC operations and ultimately customers. I discuss the unexpected and complex geologic conditions encountered in the 14th Right longwall panel and subsequent recovery efforts. I demonstrate why Daymark's allegations stating the Company and BCC were imprudent in the management of the mine are unfounded. I also explain and support the actions taken by the Company that demonstrate its prudence with respect to the proposed generation plant outage adjustments identified in the audit report.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I am currently PacifiCorp's Senior Vice President of Thermal Generation and Mining. Prior to November 2017, I was the Vice President of Coal Generation and Mining since March 2015, and Vice President of Generation from January 2010 to March 2015. For 29 years before that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's Generation organization, including the plant manager position at the Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I am responsible for operating and maintaining PacifiCorp's coal- and gas-fired generation fleet, coal fuel supply, and mining.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the utility commissions in Utah, Oregon, Washington, and Wyoming.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. My testimony:

- Explains why the Joy longwall was purchased by BCC;
- Provides information demonstrating the strategic evaluation, purchase, and implementation of the Joy longwall at BCC was prudent and occurred only after technological and geological assessments were complete;
- Highlights actions taken by BCC to inform operators of challenging geologic conditions in the 14th Right longwall panel, providing Joy longwall on-site set up

- and operating direction with JoyGlobal representatives prior to commencing operations, and classroom and hands-on Joy longwall training with JoyGlobal;
- Provides background information showing that the Joy longwall performance was exceeding expectations before approaching cross-cut 18 in the 14th Right longwall panel;
- Discusses unexpected geologic conditions encountered near cross-cut 17, the complexity and severity of those conditions and actions taken by BCC in an attempt to resume coal production activities;
- Describes longwall recovery efforts and demonstrates that all recovery efforts deemed safe and reasonable were exhausted prior to the abandonment of the longwall;
- Discusses observations detailed in the root cause analysis investigative report prepared by BCC;
- Demonstrates that Daymark's allegations the Company was imprudent in the management of the mine are unfounded.
- Demonstrates the Company was prudent in managing the plant resources, and the outage adjustments identified in the audit report are unwarranted.

BRIDGER COAL COMPANY

Q. Please describe BCC.

A. BCC is a joint venture that mines coal at the Jim Bridger coal mine for delivery to the adjacent Jim Bridger power plant. PacifiCorp (through its wholly-owned subsidiary Pacific Minerals, Inc.) owns a two-thirds interest in BCC, and Idaho Power Company (through its wholly-owned subsidiary Idaho Energy Resources Co.) owns a one-third interest. PacifiCorp and Idaho Power Company have the same ownership percentages in the Jim Bridger plant as in BCC. BCC began supplying coal extracted from surface mining operations to the Jim Bridger plant in 1974.

Q. When did BCC begin development of the underground mine?

A. In 2004, BCC began developing the underground mine infrastructure using continuous miner equipment.

Q. Did the Company's original underground mine plan incorporate longwall mining techniques?

A. Yes. Longwall mining is highly productive and provides a cost benefit relative to continuous mining operations. In longwall mining operations, continuous miner section equipment develops entries that provide access to large blocks of coal referred to as panels that can be efficiently extracted with longwall mining equipment. A contract was signed with DBT Group[1] in 2005 to construct the longwall that would be used at the mine. Longwall operations using the DBT longwall began in March 2007.

THE JOY LONGWALL ACQUISITION

Q. If BCC had the DBT longwall, why did BCC purchase the Joy longwall?

A. As mining at BCC's underground mine continued, extensive surface coal exploration programs along with detailed in-mine geologic mapping confirmed that coal seam thickness and coal seam structural geology variability increased. The Joy longwall, manufactured by JoyGlobal,[2] had been in operation at the Company's Deer Creek Mine in Central Utah which was shuttered in early 2015. The Joy longwall would therefore

[1] DBT Group was a German based underground mining equipment manufacturer that was acquired by Bucyrus International Inc. in 2007 which was subsequently purchased by Caterpillar Inc. in 2010.
[2] JoyGlobal Inc. is a Wisconsin based mining equipment manufacturer that was acquired by Komatsu Ltd. in 2017.

be available at BCC provided that technical analyses concluded the longwall could operate effectively there. The primary advantage the Joy longwall had over the DBT longwall was that the Joy longwall could operate more effectively at thinner coal seam thicknesses than the DBT. The effective operating range of the DBT longwall extends from 10.5 to 12 feet while the effective operating range of the Joy longwall extended from seven to 10 feet. The lower operating height specification of the Joy longwall would increase the flexibility of the longwall to overcome challenges of changes in coal seam thickness and variations in the structural geology. The flexibility provided by the Joy longwall would also decrease the run-of-mine ash content of coal produced.

Q. Prior to selling the Joy longwall to BCC, did the Company complete an evaluation to determine whether the Joy longwall could successfully operate in the known geologic conditions at BCC?

A. Yes. The Company and BCC's technical groups (engineering and geology) with the assistance of Malecki Technologies Inc. ("MTI"), a geotechnical engineering consultant, and JoyGlobal evaluated the potential benefits of using the Joy longwall at BCC beginning in early 2014 and concluded in the summer of 2015 that the Joy longwall would provide operating and costs benefits to BCC. This evaluation directly compared specifications of each longwall system (the DBT and the Joy) and determined the potential viability of the Joy longwall system related to BCC's coal reserve. Key specification factors (shield capacity, shield canopy tip-to-face and floor pressure) were compared between the DBT longwall and the Joy longwall. The group concluded the Joy longwall would provide operational benefits with regard to tip-to-face, floor pressure, and range of operating cutting height. In addition, the Company evaluated the effective remaining life of the Joy system (number of cycles), and concluded that the Joy longwall could be used by BCC through the expected life of the underground mine.

THE JOY LONGWALL - 14TH RIGHT

Q. Did the Company develop a specific geologic longwall report for the 14th Right longwall panel?

A. Yes. Consistent with established geologic procedures, BCC develops a comprehensive geologic report for each longwall panel. The report, included as Confidential Exhibit RMP___(DMR-1R), documents geologic, hydrologic, geotechnical, and coal quality projections of each longwall panel. To develop the report, Company and BCC geologic staff conduct detailed geologic in-mine mapping of each gateroad and the setup entries. Data mapping includes; coal thickness, coal quality—channel samples, roof and floor geology, hydrologic characteristics, general mining conditions, and geotechnical information. In addition, extensive surface exploration data is used to detail mid-panel geologic trends and longwall extraction conditions.

Q. Was the report based on comprehensive data that was analyzed and presented by professional experts?

A. Yes. The longwall panel reports are prepared by licensed professional geologists experienced in underground coal mining geology. Reports are distributed to management and discussed with longwall supervisors.

Q. Were the contents of the 14th Right longwall report discussed with mine management and longwall section supervisors?

A. Yes. The report was provided to and discussed with mine personnel in advance of mining the longwall panel. In addition, the BCC mine geologist visited the longwall face 22 times from September 3, 2015 to December 17, 2015 to conduct surveys. The surveys document coal thickness, coal quality, roof and floor geology, hydrologic characteristics, and general mining conditions. During these surveys, the geologist discusses the results of the surveys with the shearer operator, longwall coordinator and the foreman. Survey results are communicated to mine management.

Q. Did known gaps or voids exist in the data used to develop the detailed longwall mining report for the 14th Right panel?

A. No. BCC conducted extensive geologic investigations prior to the 14th Right extraction, including extensive surface exploration drilling to define regional and in-panel thickness trends and lithologic characteristics of the roof and floor and in-mine detailed geologic mapping of all entries to enhance the regional trends data. All of the data from exploration and in-mine mapping was incorporated into the overall geologic model to predict general mining conditions.

Q. You state there were no known gaps or voids in the data for developing the report. Does the Company have the ability to determine with 100 percent certainty all existing localized geologic conditions?

A. No. While the Company conducts extensive drilling and core sampling in the coal reserve, it is impractical and unreasonable to drill to determine with 100 percent certainty all existing geologic conditions. The industry standard consists of drilling holes every quarter of a mile. The drill holes at BCC are approximately every eighth of one mile in the location in question, which is significantly above the industry standard.

Q. Based on the information available to BCC relative to specific geologic conditions in the area and the favorable operational evaluation developed by JoyGlobal, did BCC have confidence the 14th Right longwall panel could be successfully mined using the Joy longwall?

A. Yes. BCC personnel with assistance of MTI, geotechnical engineering consultant, and JoyGlobal concluded the Joy longwall would provide operating benefits at BCC, especially with the longwall's ability to operate in lower coal seam heights than the DBT longwall. A detailed 14th Right longwall report using the data previously mentioned was developed and discussed with mine personnel. Based on the 14th Right report, BCC determined that the Joy longwall could safely and effectively mine this panel.

Q. What steps did the Company take to ensure the mining crews were adequately trained on the Joy longwall operation?

A. Although several individuals at BCC had extensive operational experience with the Joy longwall at the Deer Creek mine, JoyGlobal was on site starting August 25, 2015 to assist with the longwall set up and provide technical direction to the crews on the operation of the longwall prior to the longwall commencing operations on August 31, 2015. In addition, JoyGlobal conducted classroom and hands on Joy longwall training while the longwall was in actual operation for mine personnel during September 12, 2015 through October 9, 2015 to ensure longwall section employees could confidently operate the Joy longwall. Finally, operational manuals for major longwall section components were available as a reference for employees.

Q. Please describe the unexpected localized geologic features that impeded the Joy longwall's ability to move or retreat after BCC prudently evaluated geological and geo-technical conditions in the area and Joy longwall operating parameters.

A. As the mine approached cross-cut 18 in the 14th Right longwall panel in early to mid-December 2015, the Joy longwall intercepted two unexpected geologic features simultaneously, a mid-panel coal seam thinning trend and severe geologic structural rolls in the floor. The detailed mine map included as Exhibit RMP___(DMR-2R) projected a coal seam thickness of approximately nine feet in this area, which is well within the operating limits of the Joy longwall. However, the coal seam unexpectedly thinned to approximately six and a half feet thick at mid-face. The combination of the rapidly thinning coal seam and severity of the multi-dimensional structural rolls (shown in Exhibits RMP___(DMR-3R) and RMP___(DMR-4R)) in the floor forced equipment operators to alter the mining horizon to limit contact with the hard sandstone floor. The severity of the structural rolls increased as the longwall retreated towards cross-cut 17. The structural rolls were both parallel and perpendicular to the face. In addition, the hard sandstone floor, normally approximately two feet thick, thinned at the crowns of the structural rolls to less than one foot thick. The combination of the thinning coal seam, thinning sandstone floor, and severity of the structural rolls exceeded the capacity of the shearer to maneuver through the coal face without trimming into the hard sandstone floor and the roof. As the crews struggled to navigate through these difficult conditions, the hard sandstone crown was cut, which exposed the incompetent paleosol or claystone under the hard sandstone floor.

Q. **Please explain what corrective actions BCC took to navigate through the complex and rapidly changing geologic conditions.**

A. Crews attempted to alter the longwall mining horizon by changing the cutting angle of the shearer to overcome the structural rolls. Longwall crews continuously evaluate mining conditions encountered (coal seam thickness trends and structural features) along the face and attempt corrective measures to mitigate the changing mining environment. At times during mid-December, longwall crews were able to alter the mining horizon to effectively stay within the coal seam and limit incidental contact with the hard sandstone floor.

Q. **Briefly describe operating limitations that longwall section equipment has relative to rapidly changing geological conditions.**

A. The longwall is a large, highly mechanized piece of equipment with some flexibility to navigate various geologic features including changes in seam thickness and structural changes. However, in the case of the 14th Right longwall panel, the severity of the rolls in conjunction with the thinning seam exceeded the capacity of the shearer to navigate through without trimming both the hard sandstone floor and the roof. When the rolls are extremely severe, as in the case of 14th Right, as the shearer traverses along the face of the coal seam, the roof and floor must sometimes be removed for clearance especially at the transition zones of the structural rolls.

Q. **Please describe the operational and production performance of the Joy longwall prior to December 2015.**

A. The Joy longwall exceeded expectations in terms of productivity and was consistent with projected coal quality. For the period from startup on August 31, 2015 to the end of November 2015, productivity of the Joy longwall exceeded each of the measured metrics (budgeted tonnage by [redacted] percent, budgeted feet advanced by [redacted] percent, budgeted tons/shift by [redacted] percent and budgeted feet/work shift by [redacted] percent). Quality of coal produced from September through November from the Joy longwall (14th Right panel) averaged 12 percent ash which was below the Jim Bridger plant target delivery specification of [redacted] percent ash.

Q. Did the Company and BCC investigate the circumstances surrounding the abandonment of the Joy longwall?

A. Yes. The Company and BCC completed an in-depth root cause analysis and prepared the report titled "FINAL Report of Investigation – Joy Longwall 14th Right Investigation" dated October 13, 2016 shortly after the decision was made to stop the longwall recovery efforts.

Q. Please highlight the findings in the root cause analysis report.

A. Notably, the report was compiled after individual interviews with longwall section and mine management employees occurred. Several combined root cause analysis meetings were held with BCC, Idaho Power, and PacifiCorp representatives. Information gathered during this process is contained in the report. The report identified the following seven items as reasons contributing to the unexpected Joy longwall event:

1. The coal seam thickness thinned and a mid-face structural roll was encountered simultaneously.
2. Although crews were trained extensively and several had previously operated this longwall at the Deer Creek mine, operating the Joy longwall in the unique geological conditions at BCC was new to all employees.

3. Shearer operators cut into the hard sandstone floor to control roof caving and minimize ash contamination and did not adequately communicate issues to management employees.
4. The thinning coal seam forced the shearer operator to cut the crown that was caused by a pronounced roll to maintain the cutting height required to allow the shearer to pass the shields. This resulted in the shearer exposing the incompetent claystone.
5. Longwall crews did not follow consistent operating practices (spotting shields and climbing out of the claystone).
6. The crews had to manually remove material that had fallen from the roof on the face conveyor (pan) resulting in excessive downtime.
7. While equipment was maintained properly, significant unplanned mechanical downtime occurred.

The report also discusses challenges associated with geology, hydrology, scheduling adjustments and a reduced available workforce driven by the holiday period, significant unexpected mechanical downtime, inconsistent operating practices and communication, and the absence of written procedures for cutting the hard sandstone floor and catching top rock.

Q. Daymark noted, among other concerns, that the lack of a steady retreat rate at the Bridger mine was a factor that contributed to the Joy longwall failure. Please explain why the longwall could not move at a steady rate.

A. During the timeframe of December 23, 2015 to December 29, 2015, the underground mine experienced significant operational issues such as roof flushing, frozen stacking tubes and mechanical problems that prevented the longwall from moving. Most notably, longwall crews were faced with rocks flushing or falling from the roof at the longwall mine face due to the poor roof conditions. The flushing caused downtime and slowing of the mining process in order to manually move rocks off of the panline to restart the chain conveyor. The rocks were then moved back into the pan and conveyed out of the mine. The flushing of the roof was also pushing the shearer into the floor. Additionally, the stacking tubes at the surface of the underground mine were frozen solid with coal for a time due to extremely cold weather. The frozen stacking tubes prevented the conveyor system from operating effectively.

Q. Do Daymark advisors and consultants have expertise or experience in coal mining operations or consulting?

A. No. As stated in their testimony and report, while Daymark has extensive expertise in utility operations they do "not have specific expertise in coal mining operations."[3] Additionally, although "sound operations are equally applicable across a multitude of industries"[4], the communication and documentation procedures for electric transmission, distribution, and generation are significantly different than those faced in the underground mining environment.

Q. Please give further details about the eight items listed in the "Methods to Prevent a Reoccurrence" section of the root cause analysis report.

A. As described below, the majority of the items discussed in the "Methods to Prevent a Reoccurrence" section emphasize a need to improve existing practices and/or procedures as opposed to an absence of procedures that may or may not be standard in

[3] Daymark Energy Advisors EBA Audit Report, page 4.
[4] Ibid., page 4.

the industry.

1. Written longwall standards. Formal written longwall procedures have been in-place since longwall operations began at the underground mine in March 2007. Additionally, written standards were formalized in August 2017 and continue to be refined.
2. Additional geologic training. Historically, geologic longwall reports were developed and provided to management employees. Maps identifying coal seam thickness contours, roof lithology, drilling data, etc. were provided to all longwall section employees and verbal discussions occurred on an as needed basis. However, a written Longwall Standards document was developed after the Joy longwall event that requires all longwall section employees meet with Company geologists for training prior to coal extraction from a new longwall panel and as changing geologic conditions dictate.
3. Expanded geologic operating plans. Historically, operating plans were developed and discussed with all longwall section employees and mine management personnel based on discussions and input from Company geologists. However, the Longwall Standards document formalizes the communication process (both verbal and written) between operators, longwall section staff (management and union), and geologists.
4. Shearer operator communication. Historically, shearer operators have verbally communicated with each other, foreman and geologists regarding operational issues. However, the Longwall Standards document formalized the communication process to be both verbal and written.

5. Shift change communication. Historically, operators verbally communicated operational and geological conditions to the on-coming shift and prepared written production reports. The written production reports were not always reviewed by on-coming shift supervisors. The Longwall Standards document requires operators and supervisors to provide written reports to on-coming crews to ensure complete and accurate information is provided to shift supervisors.
6. Supervisor documentation. Historically, supervisors have evaluated changing face conditions, made operating adjustments and verbally communicated changes to other longwall employees. The Longwall Standards document requires supervisors to document changing conditions in production reports.
7. Mechanical availability. The referenced report states that "while equipment was being maintained properly, unplanned mechanical downtime resulted in the inability to run the longwall during the initial timing of the event". The Company recognized that not having a spare part contributed to several hours of downtime during the longwall event. The Company has reviewed and updated the critical spare longwall parts list to mitigate mechanical delays and the Longwall Standards document requires all longwall employees to report mechanical problems to maintenance personnel immediately to ensure timely repairs occur.
8. Adequate staffing levels. Historically, operating shifts at the mine were reduced from two to one shift per operating day during extended holiday periods. This practice did not create operational issues prior to the 14th Right longwall event.

In December 2015, the Company followed call-out procedures contained in the collective bargaining agreement, but represented employees declined to work unscheduled shifts. Therefore, the Company is now scheduling more employees to work during holiday periods when conditions warrant, and attempts to manage coal production activities to avoid longwall moves over extended holiday periods. In addition, the Company signed a Memorandum of Agreement with the union to provide enhanced workforce coverage during longwall move periods.

Q. Why did the Company perform an investigation?

A. The Company considered it important to understand the events and issues that resulted in the abandonment of the Joy longwall and to develop actions to prevent a future occurrence. While the Company's actions were prudent with respect to the purchase, use, and recovery attempts of the longwall the root cause analysis was done with a critical view in an effort to continuously improve our operations.

JOY LONGWALL RECOVERY EFFORTS

Q. Please summarize Joy longwall recovery efforts.

A. The longwall recovery efforts were conducted over a nine month period using traditional and state-of-the art technologies. Not all the methods discussed and evaluated were attempted due to safety and operational concerns. Longwall recovery efforts were discussed with experienced mine personnel, industry experts, vendors and the Mine Safety and Health Administration ("MSHA"). Recovery methods used included:

- Pumped grout from the surface to an area above the shields to consolidate roof material.

- Pumped a chemical into the floor to fill voids and increase compressive strength.
- Pumped various types of foams, chemicals, and grouts above and below the shields from the longwall face to fill voids and consolidate roof material.
- Installed wooden crib blocks underneath the shields to stabilize floor conditions.
- Pumped various types of glue into the face to consolidate and stabilize face conditions.
- Installed one inch by ten foot long re-bar at an angle near the top of the shields to provide additional structural face support.
- Horizontally drilled holes under the shields and face conveyor and then circulated a refrigerant to freeze and stabilize the floor.
- Took taper cuts with the shearer in the headgate area to reduce abutment pressures on the face.
- Constructed plywood beams to form bridges to distribute shield floor loading.

Q. Did BCC solicit input from industry experts to ensure all reasonable recovery techniques were considered?

A. Yes. BCC solicited input and services from industry experts, contractors, mine operators and MSHA in an effort to safely and effectively recover the Joy longwall and resume production activities. Please refer to Confidential Exhibit RMP___(DMR-5R) for the timeline of recovery efforts and industry experts consulted.

Q. At what point and why did the Company determine the Joy longwall was to be abandoned in place?

A. On October 7, 2016 the Company made the decision to stop further efforts to recover the longwall due to severe roof failure around several shields. The roof failure resulted in an unsafe condition that was too dangerous for people to continue recovery efforts.

Q. In your opinion, was the Company prudent in its actions taken for the Joy longwall issue either in its operation or in the recovery efforts?

A. Yes. The Company was diligent in its evaluation of the use of the Joy longwall, it's evaluation of the predicted mining conditions, the training of Company employees, and the prudent efforts to recover the longwall using several techniques and outside resources. Daymark's review focuses on the Company's root cause analysis and takes parts of that critical review to make their determination. Daymark does not have mining expertise and did not appear to look at the incident with the Joy Longwall in its entirety. When all the information is taken into account the Company's actions were prudent and recovery of the Joy longwall expenses should be recovered.

GENERATION PLANT OUTAGE ADJUSTMENTS

Overview of plant outages

Q. Have you reviewed the Daymark report on plant outages and do you agree?

A. Yes. I have reviewed the report, and I do not agree with Daymark's generalization that the Company's involvement with third-party contractors and vendors as "casual". The Company takes its responsibilities very seriously and manages contractors diligently. Daymark assumes that if a contractor makes a mistake it means the Company did not manage that contractor prudently. This expectation is unrealistic and unfair. The

Company closely monitors its contractors, but cannot be expected to micromanage every task made by a contract employee. Doing so would require the Company to have as many people supervising the contractors as the contractor has employees. The standard Daymark suggests is simply unreasonable. The Company manages its thermal generation fleet very effectively to the benefit of our customers. In 2016, the Company's thermal fleet performed better than the NERC average, with an equivalent availability factor (EAF) of 90.69 percent compared to the NERC average in 2015 of 82.24 percent[5]. In the following testimony, I explain the specifics around each outage Daymark recommends disallowing.

Colstrip Unit 3 Outage

Q. Do you agree with the Daymark review and recommendation related to the Colstrip Unit 3 Outage? If not, why not?

A. No. Daymark claims that the Company demonstrated a lack of urgency by waiting six years to fully address a problem. Based on the extent of the damage identified during the 2011 inspections, the operator of the Colstrip plant came up with a plan to address the issues in 2014, during the next scheduled outage, and re-inspect the area with the anticipation that an additional project would need to occur in 2017 due to continued erosion in different areas of the economizer. The tube that failed was inspected in 2014, and the wall thickness of the tube was adequate at that time. The plan was to re-inspect this area in 2017 to ensure the tubes were within acceptable wall thickness and replace any tubes that were not.

The Boiler Circulating Water Pump ("BWCP") portion of this outage was due

[5] 2015 NERC data was used because the 2016 data is not available.

to an equipment failure that occurred during the outage, and its failure was not due to imprudent practices by the Company. One of the BWCPs experienced a motor failure during startup of the unit after the tube leak repair was complete. Due to this failure, the outage was extended to repair the BWCP. This event had no connection with the tube leak and should not be included in any lost production calculations.

Q. How is the Company prudent in its participation of the Colstrip plant?

A. Rocky Mountain Power is an active owner of its jointly-owned plants where the Company is a minority partner. The Company dedicates a full-time employee to manage the interaction with all the jointly-owned plants. This person, along with others, has daily contact with the plants and raises issues with the plants on matters of operations, budget, and planning. With this involvement the Company represents the best interests of our customers.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The Colstrip Unit 3 outage was a result of material failure and not the lack of prudently established procedures and practices. The Company corrected known deficiencies in as timely and prudently as possible. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Colstrip Unit 4 Outage

Q. Do you agree with the Daymark review and recommendation relating to the Colstrip Unit 4 Outage? If not, why not?

A. No. Daymark testifies that if the #11 bearing leak resulted from failure to remove material after an oil flush, the Company should be held accountable. The bearing leak occurred from a one inch valve that was in place for the oil flush. The leak was located at the valve connection threads to the pipe. The location where the valve was installed originally had a pipe cap and a one-inch valve was installed for the oil flush. After the oil flush was completed the valve was closed and not removed. This is not a failure to remove material because the valve performed the same function as the pipe cap. The leak location could have occurred if there were a valve or a pipe cap at this location. The leak resulted from an equipment malfunction not a procedural failure.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The Colstrip Unit 4 outage was a result of a leak due to equipment failure and not procedural failure on the part of the Company or contractors. I respectfully recommend the Commission reject the adjustment proposed by Daymark.

Dave Johnston Unit 4 Outage

Q. Do you agree with the Daymark review and recommendation relating to the Dave Johnston Unit 4 Outage? If not, why not?

A. No. The condenser tube sheet RTV repair was entirely effective from 1988 until June 2009, with only minor RTV repairs throughout that time period. In June 2009, the first significant leak associated with the RTV occurred. In 2009, the Company began the process to permanently repair the condenser damage by replacing the tubes during a major outage scheduled to occur in 2020. In March 2010, a second significant leak occurred followed by a third significant leak in May 2014. It was determined that a protective tube sheet coating, which was installed in 1987, had significantly deteriorated. The deteriorated protective coating prevented proper adhesion of RTV to the tube sheet making further RTV repairs of the tube sheet difficult. The repair was completed after the unit had been online for eight days. Prior to the end of 2014, engineering had reviewed potential solutions, received quotations, and determined that epoxy cladding the tube sheet was the most economical solution. The epoxy cladding was scheduled for installation during the 2017 planned unit overhaul due to the eight day installation time. In March 2016, another leak occurred and the epoxy cladding was installed in one side (half) of the condenser during derated operation. The other side (half) was completed as planned during the scheduled overhaul which began March 2017.

Q. Do you believe an appropriate standard of prudence was exercised by the Company in its operation of Dave Johnston Unit 4?

A. Yes. The decision by the Company to replace the 26 year old RTV with an epoxy coating during a planned unit overhaul was prudent and in the best interests of customers.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The lost generation was a result of a leak due to equipment failure and not procedural failure on the part of the Company or contractors. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Gadsby Units 4, 5 and 6

Q. Do you agree with the Daymark review and recommendation relating to the Gadsby gas pipe line outage? If not, why not?

A. No. Daymark asserts that the Company demonstrated lack of a focus on proper planned maintenance for this line. The Company tested the cathodic protection in 2014 and 2015, prior to the failure, with no indication of a system problem. The leak in question was discovered during a weekly gas leak check which prompted shutdown of the system due to safety concerns. The pipe was exposed and found in very good condition along the majority of the pipe including where the cathodic protection was connected. However corrosion and pitting was found at elbows and joints where the pipe was coated or wrapped in the field after installation. The pipe was pressure tested with nitrogen after being exposed and no leak was found. Questar Gas also assisted in ground monitoring to help find the leak. The leak was assumed to be a very small pin hole in the vicinity of the highest ground level gas concentration between Unit 4 and 5 stacks. After approximately 50 percent of the pipe was exposed and no definitive leak had been found it was determined the most prudent course of action was to replace the pipe with above ground piping due to the uncertainty of the location of the leak and premature pitting found in isolated areas of the pipe. This avoided additional excavation of the remaining pipe and any future incidents due to the pitting discovered.

Q. Do you believe that the duration of the outage was excessive?

A. No. The Company initiated a plan immediately to install temporary piping above ground to allow for a well-designed and cost-effective plan to replace the underground piping. The temporary piping was fabricated in sections away from the site while underground gas monitoring was taking place. The Company was very effective in installing the temporary piping in a safe, expeditious and cost effective manner.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The Company's response to the Gadsby gas pipe line outage was prudent. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Gadsby Unit 6 Outage

Q. Do you agree with the Daymark review and recommendation relating to the Gadsby Unit 6 outage? If not, why not?

A. No. Daymark testified that this was a Company failure to follow industry practices, recommending a disallowance. The Company witnessed the manufacture and testing of the exciter at the National Electric Coil ("NEC") shop. This work was completed by NEC not General Electric ("GE"). The shop testing in 2015 met industry standards. The exciter was transported and installed by NEC at the Gadsby site and witnessed by a professionally licensed electrical engineer. The installation met industry standards. The unit operated successfully for several months. Once stationary coils began failing, tests were completed to determine the root cause. GE was brought in to complete extensive testing. Initially, GE thought that the insulation on the coils had deteriorated. However, when a new coil failed, the focus was turned to other areas such as stray currents and the excitation system. Basler Electric Company ("Basler") was later brought in to investigate the voltage regulating equipment. Individual components were tested and eliminated as sources of the failures. NEC was also notified of the issues and they believed it was not the exciter. GE performed an extensive investigation of the failures. Eventually, GE removed the Basler voltage regulator equipment from the circuit and determined the new rotating exciter was imposing an imbalance in the three phase resistance causing the stationary coil to fail. When NEC was notified they initially disagreed based on their shop tests but later agreed once they were on site and confirmed the same tests that GE had completed. As previously stated, the unit met standards in the shop and operated successfully for several months prior to failure. The Company took prudent and reasonable steps to ensure that the equipment was built and installed to industry standards.

Q. Do you believe that the duration of the outage was excessive?

A. No. The Company initiated a plan immediately with NEC to repair the faulty exciter and replace the coils.

Q. Do you believe the Company met its standard of prudence in the management of the Gadsby Unit 6 outage?

A. Yes. The Company prudently prepared and responded to the coil failures by methodically testing components to determine the root cause. Once the root cause was determined to be the exciter, NEC was immediately involved to expeditiously repair the exciter.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The Company's response to the Gadsby Unit 6 outage was prudent. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Hermiston Unit 1 Outage

Q. Do you agree with the Daymark review and recommendation relating to the Hermiston Unit 1 Outage? If not, why not?

A. No. The plant is operated by Hermiston Generating Company ("HGC"). When

Hermiston Unit 1 tripped offline on August 2, 2016, it was due to a #11 failed combustion can. At the time, GE determined that the can failure was due to a lack of purge air; further investigation found that the purge air valve was shut. Due to a recent outage, the plant thought that the valve had been inadvertently shut by a contractor since the valve is normally left open. When Hermiston Unit 1 tripped offline on September 18, 2016 with the same issue, GE, the subject matter expert, and HGC performed troubleshooting and noted that the purge air valve was closed again. Based on no contractors being on site and interviews conducted amongst plant personnel, it was determined that the purge air valve shut based on high vibration from the combustion turbine. After the September 18, 2016 incident, GE conducted additional research and confirmed that there have been other instances of valves inadvertently closing as a result of high vibrations causing wear in the actuator and valve, developing excess play to allow it to close easily. Excess play in the purge air valve was not suspected as the cause on August 2 due to contractors recently being on site, since there was no history of issues with the purge air valve, and it was not identified as a possible cause in detailed discussions with the subject matter expert.

Daymark states that they believe it is unlikely that normal amounts of vibration, even over many years, would lead to the closing of this valve. This statement is made without basis. GE has multiple documented cases of this very phenomena occurring.

Q. Do you believe an appropriate standard of prudence was exercised by HGC its operation of Hermiston Unit 1?

A. Yes. As I have described, HGC utilized industry subject matter experts to assist in the troubleshooting and determining the root cause of the combustion can failure. The course of action executed was prudently planned and checked by industry subject matter experts. The specific incident that occurred was the result of unknown material failure, and not the lack of prudent operations. Since the incident, the plant operator has replaced the purge air valve and conducts routine inspections to verify proper operation.

Q. How is the Company prudent in its participation of the Hermiston plant?

A. The Company is an active owner of its jointly-owned plants. The Company dedicates a full-time employee to manage the interaction with all the jointly-owned plants. This person, along with others, has daily contact with the plants and poses questions and raises issues with the plants on matters of operations, budget, and planning. With this involvement the Company represents the best interests of our customers.

Q. What is your recommendation to the Commission with respect to the adjustment proposed by Daymark?

A. The Hermiston Unit 1 outage on September 18, 2016 was the result of failed equipment and not the lack of prudent operations by the Company. I respectfully recommend that the Commission reject the adjustment proposed by Daymark.

Naughton Unit 2 May 2016 Outage

Q. Do you agree with the Daymark review and recommendation relating to the Naughton Unit 2 outage on May 28, 2016? If not, why not?

A. No. Daymark testified that they believe the Company is responsible for the inappropriate actions of the third parties it hires on behalf of its customers. In this case, the project manager had discussed bearing clearances with the contractor specifically to avoid the type of problem that occurred. The Company uses competitive bidding procedures and selected a qualified vendor based on these policies. In this case, the vendor was the original equipment manufacturer of the equipment. The Company was aware of the critical need for correct bearing clearances and discussed this with the vendor prior to the work. Contracts do not typically cover replacement power costs as stated since they involve a broad range of circumstances and damages that is difficult to identify and quantify. It is anticipated that if contracts were sought that covered these types of damages, the cost of such contracts would increase dramatically and result in increased costs to the Company and customers. The actions the Company takes when procuring services is prudent, within industry practices and in the best interests of the customer.

Naughton Unit 2 June 2016 Outage

Q. Do you agree with the Daymark review and recommendation relating to the Naughton Unit 2 outage on June 6, 2016? If not, why not?

A. No. Daymark claims that a fire should trigger more attention and analysis than what was provided. The response to the fire was appropriate as personnel quickly engaged and extinguished the fire. The fact is that the subsequent investigation by plant and fan company personnel could not identify a definite root cause of the fire. Based on proximity to the coal pile, it is speculated that coal dust could have been the source of this fire but is not conclusive. Daymark also states that despite the company being aware that the area where the fire occurred was prone to coal dust buildup, it waited until a fire occurred to create preventative maintenance work. It was not known prior to the fire that these areas may be prone to coal dust accumulation. The area is not visible during operation. When the similar area on Unit 1 was checked, there was minor buildup of coal dust. The follow-up actions were initiated to help prevent any future issues, but the implication that this was a known and neglected area is not true. Coal dust is a recognized hazard and plant personnel work diligently to mitigate this hazard.

Jim Bridger Unit 4 Outage

Q. Do you agree with the Daymark review and recommendation relating to the Jim Bridger Unit 4 Outage? If not, why not?

A. No. The root cause of the failure of the #41 PA Fan Motor Failure was analyzed. Although a specific root cause analysis was not performed, the mechanism and root cause of the failure was diagnosed. It was found that the source was a lack of lubrication being supplied to the bearing and as a result the bearing failed. When the bearing failed, the rotor contacted the stator. The heat that was generated also melted the aluminum rotor bars. Additionally, during the analysis of the root cause, it was found that a thermal couple had been installed in a location that was reading lower than normal operating temperatures on the bearings. With all the factors analyzed, the Company worked with the motor shop to evaluate the repairs needed to return the motor to a usable state. It was determined that the Company would need to replace the rotor, restack the rotor, rewind the motor, and replace the bearings. It was at this point that the cost of the rebuild and time required for the repairs against the option of replacing the motor. It was decided that the cost to repair the motor and time required was the more costly option and extended loss of generation. After careful consideration, the decision was made to install a new motor and modify the sole plate to allow for the alignment to hold closer tolerances. This option allowed the opportunity to return the unit to full generating capacity much sooner. In addition, the thermal couples were placed in an area that would show accurate temperatures and display to the control room for monitoring. The site glasses were also modified to ensure operators could verify levels to add lubrication as needed. The modifications to the site glass and thermal probes have been expanded to all the PA Fans. With this analysis and determination of the root cause premature failures will be prevented moving forward.

Q. What is your recommendation with respect to the Daymark generation plant outage adjustments?

A. As stated above, the Company took prudent actions in all of the outages listed. Daymark did not fully examine the details around these outages and, in some cases, uses their own opinion without any supporting evidence. Managing these resources requires a balanced approach for the best overall interests of our customers and includes risks. As shown above, the Company evaluates the costs and risks when managing the assets.

Q. Do you agree that the Company prudently managed the Joy longwall and the generation plant outages?

A. Yes. As stated earlier, the Company demonstrated that it diligently evaluated and managed the installation and the operation of the Joy longwall. The Company also demonstrated that the events that led up to the issue with the longwall were a result of two unknown geological features that occurred simultaneously and exceeded the capacity of the longwall to maneuver through this area. The Company has also showed the efforts to recover the longwall were prudent by using several techniques and resources. Finally, with respect to the plant outages, the Company has shown that it diligently manages these resources and the actions taken were prudent and in the best interests of the customer.

Q. Does this conclude your response testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(DMR-1R)
Docket No. 17-035-01
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Response Testimony of Dana M. Ralston
14th Right Longwall Panel Report

December 2017

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

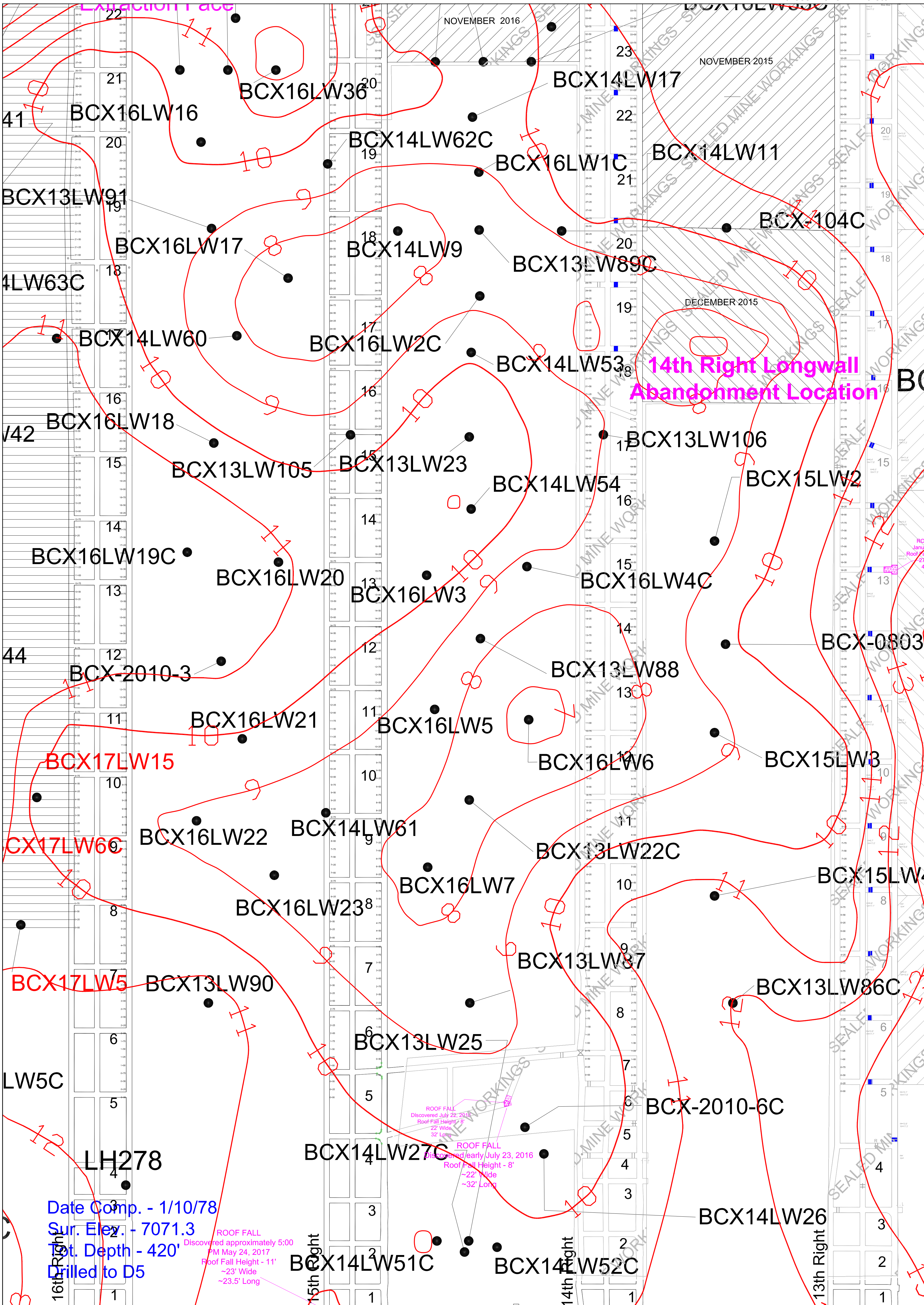
Rocky Mountain Power
Exhibit RMP___(DMR-2R)
Docket No. 17-035-01
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Response Testimony of Dana M. Ralston
Bridger Coal D41 Thickness

December 2017



Bridger Coal
13th - 16th Right
D41 Coal Seam Thickness
Updated September 2017

Rocky Mountain Power
Exhibit RMP___(DMR-3R)
Docket No. 17-035-01
Witness: Dana M. Ralston

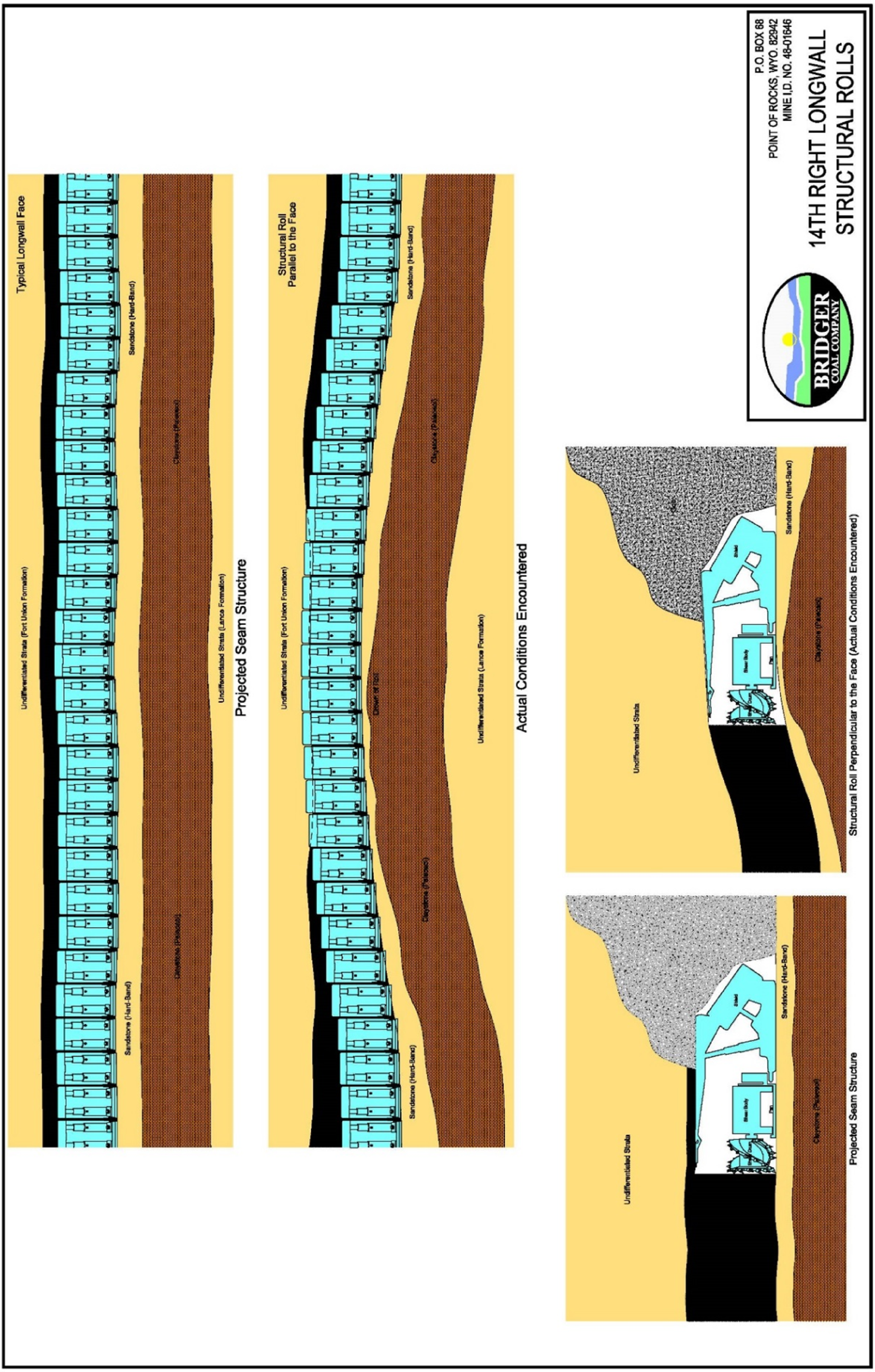
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Response Testimony of Dana M. Ralston
14th Right Structural Rolls

December 2017

14th Right Longwall Structural Rolls



Rocky Mountain Power
Exhibit RMP___(DMR-4R)
Docket No. 17-035-01
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Response Testimony of Dana M. Ralston
Example of A Structural Roll in the Floor

December 2017

<u>Example of a Structural Roll in the Floor –</u>
<u>Near Bridger Coal Co., Point of Rocks, Wyoming</u>

Example of a Structural Roll in the Floor

P.O. BOX 68
POINT OF ROCKS, WYO. 82942
MINE I,D. NO. 48-01646

BRIDGER COAL COMPANY

EXAMPLE OF A
STRUCTURAL ROLL
IN THE FLOOR

REDACTED
Rocky Mountain Power
Exhibit RMP___(DMR-5R)
Docket No. 17-035-01
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Response Testimony of Dana M. Ralston
Joy Longwall Recovery Chronology

December 2017

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

CERTIFICATE OF SERVICE

Docket No. 17-035-01

I hereby certify that on this 19th day of December 2017, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

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Katie Savarin

Katie Savarin
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