ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 310
Salt Lake City, Utah 84116

March 15, 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 to Decrease the Deferred EBA Rate through the Energy Balancing Account Mechanism

In accordance with Utah Public Service Commission Rule 746-1-203, Rocky Mountain Power hereby submits for electronic filing its Application to decrease the deferred EBA rate through the Energy Balancing Account mechanism. As requested by the Commission, Rocky Mountian Power is also providing seven (7) printed copies of the filing via overnight delivery. Workpapers supporting this application will also be provided electronically.

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
Bob.lively@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Bob Lively at (801) 220-4052.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

cc: Service List – Docket No. 17-035-01

## CERTIFICATE OF SERVICE

**Docket No. 17-035-01**

I hereby certify that on this 15th day of March 2017, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

| **Utah Office of Consumer Services** | |
|---|---|
| Cheryl Murray<br>Utah Office of Consumer Services<br>160 East 300 South, 2nd Floor<br>Salt Lake City, UT 84111<br>cmurray@utah.gov | Robert Moore<br>Assistant Attorney General<br>500 Heber M. Wells Building<br>160 East 300 South<br>Salt Lake City, Utah 84111<br>rmoore@utah.gov |
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| **Division of Public Utilities** | |
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*Attorneys for Rocky Mountain Power*

**BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO DECREASE THE DEFERRED EBA RATE THROUGH THE ENERGY BALANCING ACCOUNT MECHANISM | ) ) ) ) | Docket No. 17-035-01 |

**APPLICATION TO DECREASE THE DEFERRED EBA RATE THROUGH THE ENERGY BALANCING ACCOUNT MECHANISM**

Rocky Mountain Power, a division of PacifiCorp ("Company" or "Rocky Mountain Power"), hereby submits this application ("Application") to the Public Service Commission of Utah ("Commission") pursuant to energy balancing account mechanism ("EBA") tariff Schedule 94 ("Tariff Schedule 94"), requesting approval to refund approximately $6.5 million in deferred EBA Costs ("EBAC"). The $6.5 million includes the following components: (1) approximately $11.3 million, the difference between the Actual EBAC and the Base EBAC in current base rates for the period beginning January 1, 2016 through December 31, 2016 ("Deferral Period"), (2) a credit of approximately $2.9 million for savings related to the Retiree Medical Obligation not subject to the sharing band, (3) a credit of approximately $0.7 million in coal fuel expense savings at the Hunter and Huntington plants related to the Deer Creek mine closure and not subject to the sharing band, (4) a credit of approximately $0.5 million in accrued interest, (5) a credit of approximately $0.2 million related to an adjustment for sales made to a special contract customer, and (6) approximately $9.1 million in costs representing the Utah-allocated Deer Creek mine amortization expense.

The Company is proposing to revise Tariff Schedule 94 to refund to customers $6.5 million. This overall decrease results in a refund to retail customers under Tariff Schedule 94 rate of approximately 0.3 percent.

This Application is consistent with Tariff Schedule 94, approved by the Commission (1) on July 17, 2012, as amended by the Commission's Order on EBA Interim Rate Process, issued August 30, 2012, and (2) in Dockets No. 16-035-T05 and No. 09-035-15 by orders issued May 16, 2016 and February 16, 2017, respectively (together, the "EBA Order").

The proposed EBA rate decrease reflected in this Application represents an EBA rate adjustment under Tariff Schedule 94 as set forth above. It is allocated to rate schedules pursuant to and consistent with the Commission-approved NPC allocator from the Company's general rate case filing in Docket No. 13-035-184 (the "2014 GRC"), as explained further below. Rocky Mountain Power respectfully requests that, pursuant to the provisions in Tariff Schedule 94 and the EBA Order, this decrease in Utah rates become effective, on an interim basis, May 1, 2017. In addition and in accordance with the EBA Order, the Company proposes that any difference between the 2017 EBA credits and the final amount approved by the Commission be included in new rates, effective May 1, 2018. The Company also proposes continuing the collection of the existing 2016 EBA that went into effect November 1, 2016, until the deferral balance is fully collected. The Company currently estimates the 2016 EBA deferral will be fully recovered around September 2017. In support of its Application, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon corporation, which provides electric service to retail customers through its Rocky Mountain Power division in the states of Utah, Wyoming, and Idaho, and through its Pacific Power division in the states of Oregon, California, and Washington.

2. Rocky Mountain Power is a public utility in the state of Utah and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Utah. Rocky Mountain Power's principal place of business in Utah is 1407 West North Temple, Suite 310, Salt Lake City, Utah, 84116.

3. Communications regarding this filing should be addressed to:

Bob Lively
Utah Regulatory Affairs Manager
Rocky Mountain Power
1407 West North Temple, Suite 330
Salt Lake City, Utah 84116
E-mail: bob.lively@pacificorp.com

Yvonne R. Hogle
Assistant General Counsel
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
E-mail: yvonne.hogle@pacificorp.com

In addition, Rocky Mountain Power requests that all data requests regarding this application be sent in Microsoft Word or plain text format to the following:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Informal questions may be directed to Bob Lively, Utah Regulatory Affairs Manager at (801) 220-4052.

4. Tariff Schedule 94 permits the Company to monitor total EBAC on an unbundled basis apart from other investments and expenses included in base rates and to account for historical actual EBAC that may be over or under the amount recovered in base rates through the EBA.

5. Under Tariff Schedule 94, the Company files a deferred EBAC adjustment application annually on or before March 15. Included with this filing are changes to Tariff Schedule 94 to include provision for an annual interim rate effective date of May 1.

6. The EBA deferral calculation consists of two revenue requirement components: NPC and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchased power expenses, wheeling expenses, less wholesale sales revenue. Wheeling revenue includes amounts booked to FERC account 456.1, Revenues from transmission of electricity of others. Collectively, the two components are known in Tariff Schedule 94 as "Energy Balancing Account Costs" or "EBAC".

7. During 2016, several new accounts were used in the Company's accounting system to track components of net power costs and wheeling revenues, including new accounts to track fuel expenses and NPC-related accounting entries arising from the Company's participation in the energy imbalance market ("EIM") with the California Independent System Operator ("CAISO'), as specifically described in the direct testimony of Mr. Michael G. Wilding. The new accounts fall within the main FERC accounts that make up net power costs, but the specific SAP accounts are not identified in the currently-effective Tariff Schedule 94. The new accounts are identified in an exhibit to Mr. Wilding's direct testimony as well as in the revisions to Schedule 94, included as an exhibit in Mr. Robert M. Meredith's direct testimony.

8. The deferred EBAC is determined pursuant to Tariff Schedule 94 by comparing, in a deferral period, the actual NPC and wheeling revenue to the total Base EBAC recovered in rates

as established in a general rate case. From January 2016 through May 2016, 70 percent of the difference was deferred for later recovery from or refund to customers. Effective June 1, 2016, one hundred (100) percent was deferred for later recovery from or refund to customers. In addition, several adjustments were made to actual NPC this year, as described in the direct testimony of Mr. Wilding.

9. The Deferral Period for this Application is the 12-month period beginning January 1, 2016 through December 31, 2016.

10. The request in this Application includes six components: (1) the EBA deferral credit amount ("EBA Deferral Amount") of approximately $11.3 million, (2) a credit of approximately $0.7 million in coal fuel expense savings related to the Deer Creek mine closure, (3) a credit of approximately $0.5 million in accrued interest, (4) a credit of approximately $0.2 million related to adjustments for sales made to a special contract customer, (5) a credit of approximately $2.9 million for savings related to the Retiree Medica Obligation not subject to sharing band, and (6) costs of approximately $9.1 million for the Utah-allocated Deer Creek mine amortization expense.

11. For the Deferral Period, Base NPC were set at $1.491 billion and wheeling revenue was set at $97 million.

12. Actual NPC were lower than Base NPC during the Deferral Period as a result of, among other things, a reduction in purchase power expense, a reduction in coal fuel expense, a reduction in natural gas expense and a reduction in wheeling and other expenses, partially offset by a reduction in wholesale sales revenue.

13. The Company calculated the EBA Deferral Amount for the Deferral Period using the Commission Order Method consistent with the stipulation approved by the Commission in the

2014 GRC, as set forth in detail in Exhibit RMP___(MGW-1), attached to Mr. Wilding's direct testimony.

**<u>Deferred EBA Cost Adjustment</u>**

14. Pursuant to Tariff Schedule 94, the deferred EBAC adjustment is calculated monthly and recorded as a deferred expense on the Company's books. Mr. Wilding's **Exhibit RMP___(MGW-1),** shows the detailed calculation of the EBA Deferral Amount. Adjusted Actual Total NPC from January 1, 2016 through December 31, 2016 were approximately $1,463 million. This was approximately $28 million lower than the $1,491 million Base NPC being used in this case.

15. Utah's allocated NPC before wheeling revenues were approximately $637 million. After crediting Utah-allocated wheeling revenues of approximately $44 million, Utah actual EBAC were approximately $593 million shown on line 3, or $24.74 per MWh, shown on line 5.

16. In comparison, Utah Base EBAC were approximately $628 million shown on line 6, after crediting Utah-allocated wheeling revenues or approximately $41.1 million shown on line 7, or $25.25 per MWh, shown on line 10. The monthly difference between lines 5 and 10 applied to Utah's 2016 load produces the deferred EBAC prior to application of the cost-sharing band of approximately $12.7 million, shown on line 12.

17. The Deferred EBAC for the January 2016 through May 2016 period, after applying the 70/30 percent EBA sharing band, is approximately $3.3 million on line 13. The Deferred EBAC for the June 2016 through December 2016 period, is approximately $8.0 million on line 14, for a total Deferred EBAC for the entire deferral period of $11.3 million, the sum of line 13 and line 14. One hundred (100) percent of the coal fuel savings related to the closure of the Deer Creek mine in the amount of about $0.7 million are shown on line 15. One hundred (100) percent of Retiree

Medical Obligations savings also related to the closure of the Deer Creek mine in the amount of approximately $2.9 million are shown on line 16. A credit adjustment for sales to a special contract customer of $0.2 million, subject to a deadband, is shown on line 23. Interest provisions of approximately $400 thousand for the Deferral Period (January 1, 2016 through December 31, 2016) and of $129 thousand (from January 2017 through April 2017) are shown on lines 28 and 31, respectively. The Deer Creek amortization expense of approximately $9.1 million is reflected on line 30. The total ending deferral amount of approximately $6.5 million is shown on line 32.

18. A summary of the total requested EBA recovery is shown in the table below.

| Calendar Year 2016 EBA Deferral | | | *Exhibit RMP___(MGW-1) Reference* |
|---|---|---|---|
| Actual EBAC ($/MWh) | $ | 24.74 | *Line 5* |
| Base EBAC ($/MWh) | $ | 25.25 | *Line 10* |
| $/MWh Differential | **$** | **(0.51)** | |
| Utah Sales (MWh) | | 23,977,388 | *Line 4* |
| EBA Deferrable* | $ | (12,683,869) | *Line 12* |
| EBA Deferral at 70% Sharing | $ | (3,266,628) | *Line 13* |
| EBA Deferral Beginning June 1, 2016 | $ | (8,017,258) | *Line 14* |
| Coal Fuel Savings not Subject to Sharing* | $ | (735,336) | *Line 15* |
| Incremental Non-Fuel FAS 106 Savings not Subject to Sharing* | $ | (2,941,860) | *Line 16* |
| Special Contract Customer Adjustment Subject Deadband* | $ | (200,718) | *Line 23* |
| Total Deferrable | $ | (15,161,800) | *Line 24* |
| Interest Accrued through December 31, 2016 | $ | (407,205) | *Line 28* |
| Interest Jan. 1, 2017 through April 30, 2017 | $ | (129,237) | *Line 31* |
| Deer Creek Amortization Costs | $ | 9,155,405 | *Line 30* |
| **Requested EBA Recovery** | **$** | **(6,542,837)** | *Line 32* |

** Calculated monthly*

**Proposed Tariff Sheets**

19. The Company's proposal is to spread the deferred EBAC across customer classes for the Deferral Amounts consistent with the NPC Allocator agreed to by the parties and approved by the Commission in the 2014 GRC, as shown in Exhibit RMP___(RMM-1), attached to the direct testimony of Mr. Meredith.

20. The Company proposes to allocate the 2017 EBA deferral and revenues to those customer classes that are not reflected in the NPC Allocators, such as Schedule 21 and Schedule 31 customers, as described in Mr. Meredith's direct testimony.

21. The table below summarizes the proposed price changes by tariff rate schedule. Mr. Meredith's direct testimony, **Exhibit RMP___(RMM-1),** displays the Company's proposed rate spread, as discussed above. The proposal would result in an overall decrease of approximately 0.3 percent to customers in Utah. Mr. Meredith's direct testimony, **Exhibit RMP___(RMM-2),** includes billing determinants and the calculations of the proposed EBA rates in this case. Mr. Meredith's direct testimony, **Exhibit RMP___(RMM-3),** contains the proposed rates and revisions for Tariff Schedule 94.

| **Customer Class** | **Proposed Percentage Change 2017 EBA** |
|---|---|
| **Residential** | |
| Schedules 1, 2, 3 | (0.3)% |
| **General Service** | |
| Schedule 23 | (0.3)% |
| Schedule 6 | (0.3)% |
| Schedule 8 | (0.4)% |
| Schedule 9 | (0.5)% |
| **Irrigation** | |
| Schedule 10 | (0.4)% |
| **Public Street and Area Lighting Schedules** | |
| **Schedules 7, 11, 12** | (0.2)% |
| **Schedule 15** | (0.4)% |

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission approve interim rates as provided in Tariff Schedule 94 to refund the credits identified in this Application, as filed, with an effective date of May 1, 2017.

DATED this 15th day of March 2017.

Respectfully submitted,

ROCKY MOUNTAIN POWER

______________________________

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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

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Direct Testimony of Michael G. Wilding

March 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.

**Qualifications**

**Q. Briefly describe your education and business experience.**

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. I am a Certified Public Accountant licensed in the state of Utah. Prior to joining the Company, I was employed as an internal auditor for Intermountain Healthcare and an auditor for the Utah State Tax Commission. I have been employed by the Company since February 2014.

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have filed testimony in proceedings before the public service commissions in Utah, Wyoming, Idaho, California, and Oregon.

**Purpose of Testimony**

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

A. My testimony presents and supports the Company's calculation of the Energy Balancing Account ("EBA") deferral for the 12-month period from January 1, 2016 through December 31, 2016 ("Deferral Period"). More specifically, I provide the following:

- A summary of the 2017 EBA and details supporting the elimination of the sharing band and its benefit to customers;
- Details supporting the calculation of the Company's request to credit $6.5 million

(0.3 percent) to customers for EBA-related costs, interest, the Utah-allocated non-fuel saving related to the settlement of the Deer Creek Retiree Medical Obligation, the Utah-allocated Deer Creek amortization expense, and an adjustment for sales made to a special contract customer;

- Discuss the Company’s participation in the energy imbalance market (“EIM”) with California Independent System Operator (“CAISO”) and the benefits passed through to customers; and,
- A discussion of the main differences between adjusted actual net power costs (“Actual NPC”) and net power costs in rates (“Base NPC”).

**EBA Summary**

**Q. Please summarize the Company’s EBA application.**

A. The Company’s application requests to refund $6.5 million to customers. The 2017 EBA is comprised of a $11.3 million refund of deferred EBA-related costs, a credit of $2.9 million for savings related to the Retiree Medical Obligation not subject to the sharing band, a credit of $0.7 million for coal fuel expense savings related to the Deer Creek mine closure not subject to the sharing band, a $0.5 million credit of interest, a credit of $0.2 million related to an adjustment for sales made to a special contract customer, and $9.1 million for the Utah-allocated Deer Creek mine amortization expense.

**Q. Are there any changes to the EBA calculation?**

A. Yes. The first change is the elimination of the sharing band beginning June 1, 2016, as approved in the Commission’s May 16, 2016 Order in Docket No. 16-035-T05. The second change is an adjustment for sales made to a special contract customer.

**Q. Are these changes in the EBA a benefit to customers?**

A. Yes. The elimination of the sharing band, as of June 1, 2016, increases the refund to customers by approximately $1 million. The refund to customers would have been approximately $0.7 million higher if the sharing band would have been eliminated for the entire deferral period. The adjustment to the EBA for sales made to a special contract customer also increases the total EBA refund by approximately $0.2 million. I will explain the adjustment in greater detail later in my testimony.

**Q. Besides an increase in the EBA refund, are there other ways customers benefit from eliminating the sharing band?**

A. Yes. The elimination of the sharing band benefits customers as follows: 1) ensures that customers pay the actual costs for the energy they consume, no more and no less, 2) keeps the NPC component of rates just, reasonable, and in the public interest, 3) helps mitigate the need for more frequent general rate cases (“GRC”), and 4) helps ensure customers are served by a financially healthy utility.

**Q. What does this EBA infer about the effectiveness of the sharing band as an incentive mechanism to reduce NPC?**

A. The sharing band was not effective as an incentive mechanism to reduce NPC. The 2017 EBA is the first EBA without a sharing band and also the first EBA that is a refund to customers, resulting in a greater refund to customers. Previously, the sharing band rewarded the Company if Actual NPC were less than Base NPC by allowing the Company to retain 30 percent of the savings. If Actual NPC were higher than Base NPC, the Company was required to absorb 30 percent of the additional costs. If NPC are completely controllable by the Company, an effective incentive mechanism would have resulted in more years where Actual NPC was less than Base NPC.

**Q. Why was the sharing band not an effective incentive mechanism?**

A. The sharing band assumed that Base NPC was an operational standard by which to judge Actual NPC. Base NPC is set in a GRC using a forecasted test period based on what is known and expected at the time. Additionally, the Base NPC established in Docket No. 13-035-184 ("2014 GRC") included an adjustment further reducing Base NPC as part of the overall settlement.

The variables influencing NPC are generally outside of the Company's control and system operations are largely in response to these outside influences. In a GRC, the Company forecasts NPC based on these variables, which are also a forecast. In Actual NPC these variables inevitably change as the Company responds operationally to real-time variables influencing NPC. In other words, using Base NPC as the operational standard by which to judge the efficiency of actual operations is not effective because in Actual NPC, the influencing variables have changed. The variables include the load demanded by customers, weather events that affect both loads and generation from all resources, the output of qualifying facilities that the Company is obligated to purchase, and the price of natural gas and electricity as determined by wholesale markets.

Lastly, the EBA calculation adjusts for the change between base Utah retail sales and actual Utah retail sales, meaning that any over-collection or under-collection of Base NPC resulting from a change in Utah retail sales is accounted for in the EBA.

Customer demand is entirely outside of the Company's control and the sharing band amplified the over- and under-collection.

**EBA Deferral Calculation**

Q. **Please describe the Company's calculation of the EBA deferral for the Deferral Period.**

A. Table 1 below provides a summary of the total EBA deferral and a breakdown of the individual components of the EBA. Additionally, Exhibit RMP___(MGW-1) presents the detailed calculation of the EBA deferral on a monthly basis.

**Table 1**

**Annual EBA Calculation**

| Calendar Year 2016 EBA Deferral | | | *Exhibit RMP___(MGW-1) Reference* |
|---|---|---|---|
| Actual EBAC ($/MWh) | $ | 24.74 | *Line 5* |
| Base EBAC ($/MWh) | $ | 25.25 | *Line 10* |
| $/MWh Differential | **$** | **(0.51)** | |
| Utah Sales (MWh) | | 23,977,388 | *Line 4* |
| EBA Deferrable* | $ | (12,683,869) | *Line 12* |
| EBA Deferral at 70% Sharing | $ | (3,266,628) | *Line 13* |
| EBA Deferral Beginning June 1, 2016 | $ | (8,017,258) | *Line 14* |
| Coal Fuel Savings not Subject to Sharing* | $ | (735,336) | *Line 15* |
| Incremental Non-Fuel FAS 106 Savings not Subject to Sharing* | $ | (2,941,860) | *Line 16* |
| Special Contract Customer Adjustment Subject Deadband* | $ | (200,718) | *Line 23* |
| Total Deferrable | $ | (15,161,800) | *Line 24* |
| Interest Accrued through December 31, 2016 | $ | (407,205) | *Line 28* |
| Interest Jan. 1, 2017 through April 30, 2017 | $ | (129,237) | *Line 31* |
| Deer Creek Amortization Costs | $ | 9,155,405 | *Line 30* |
| **Requested EBA Recovery** | **$** | **(6,542,837)** | *Line 32* |

** Calculated monthly*

The credit for EBA-related costs of $11.3 million are calculated as the difference between the Actual NPC and wheeling revenue and the Base NPC and wheeling revenue, as established in the 2014 GRC. Prior to June 1, 2016, the difference between base and actual EBA related-costs was subject to a 70/30 percent sharing band, which has now been eliminated through the end of the EBA pilot program. The refund of EBA-related costs subject to the sharing band is \$3.3 million and the amount of the refund not subject to sharing is \$8.0 million.

The calculation of the monthly amount debited or credited into the EBA Deferral Account for the months January - May is based on the following formula:

$$EBA\ Deferral_{\ Utah,month} =$$

$$\left[\left(Actual\ EBAC\frac{_{Utah,month}}{MWh} - \ Base\ EBAC\ \frac{_{Utah,month}}{MWh}\right) \times\ Actual\ MWh_{Utah,month}\right] \text{ x } 70\%$$

For the months June - December, the same formula applies to the calculation of the monthly amount debited or credited into the EBA Deferral Account with the exception of removing the 70 percent sharing band.

**Q. What revenue requirement components are included in the EBA deferral calculation?**

A. The EBA deferral calculation consists of two revenue requirement components, NPC and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. Wheeling revenue includes amounts booked to FERC account 456.1, revenues from transmission of electricity of others. Collectively these two components are known in the Company's EBA tariff, Schedule No. 94, as Energy Balancing Account Costs ("EBAC").

Per the stipulation in Docket No. 14-035-147 ("Deer Creek Settlement"), the EBA includes 100 percent of the Utah-allocated amortization expense associated with the closure of the Deer Creek mine. The Deer Creek amortization expense will continue to be part of the EBA until it is included in base rates. Additionally, 100 percent of the Utah-allocated coal fuel expense savings at the Hunter and Huntington plants related to the closure of the Deer Creek mine were passed through to customers from January - May 2016. After June 1, 2016, the EBA deferral is no longer subject to a sharing band therefore eliminating the need for a coal fuel expense savings adjustment. The EBA also includes the non-fuel cost savings related to the settlement of Energy West retiree medical benefit obligation as a result of the Deer Creek mine closure.

**Q. How are the Utah-allocated Actual NPC calculated?**

A. Utah-allocated Actual NPC are calculated in three steps. First, unadjusted actual NPC are established on a total-company basis. Second, adjustments are made to the unadjusted actual NPC to apply certain regulatory adjustments and to remove out-of-period accounting entries. Third, the adjusted total-company Actual NPC are allocated to Utah on the basis of the 2017 Protocol.

**Q. What were the total-company adjusted Actual NPC for the Deferral Period and how were they determined?**

A. The total-company adjusted Actual NPC in the Deferral Period were approximately $1.463 billion. This amount captures all components of NPC as defined in the Company's general rate case proceedings and modeled by the Company's Generation and Regulation Initiative Decision Tool ("GRID") model. Specifically, it includes amounts booked to the following FERC accounts:

Account 447 - Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID

Account 501 - Fuel, steam generation; excluding fuel handling, start-up fuel[1] (gas and diesel fuel, residual disposal) and other costs that are not modeled in GRID

Account 503 - Steam from other sources

Account 547 - Fuel, other generation

Account 555 - Purchased power, excluding the Bonneville Power Administration ("BPA") residential exchange credit pass-through if applicable

Account 565 - Transmission of electricity by others

During 2016, several new SAP accounts were used in the Company's accounting system to track components of NPC and wheeling revenue. Specifically, new SAP accounts were established to track NPC-related accounting entries arising from participation in the EIM with the CAISO. These accounts fall within the main FERC accounts that make up the EBAC, but the specific SAP accounts are not identified in the current Schedule 94. Exhibit RMP___(MGW-2) identifies the new accounts used in 2016. The new accounts are also included in the revised tariff sheets provided in the testimony of Mr. Robert Meredith.

**Q. What adjustments are made to Actual NPC and why are they needed?**

A. The Company adjusts Actual NPC to reflect the ratemaking treatment of several items, including the buy-through of economic curtailment by interruptible industrial customers, situs assignment of the generation from Oregon solar resources procured to

[1] Start-up fuel is accounted for separately from the primary fuel for steam power generation plants. Start-up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of both Base NPC and Actual NPC.

satisfy ORS 757.370 solar capacity standard, revenue associated with a unique contract for the Company's Leaning Juniper facility, coal inventory adjustments to reflect coal costs in the correct period, and legal fees related to fines and citations included in the cost of coal. The Company also adjusts Actual NPC to remove accounting entries booked in the Deferral Period that related to operations prior to implementation of the EBA in October 2011, however there were no such accounting entries during the deferral period. Additional details regarding each of these adjustments and the impact on NPC are provided in Additional Filing Requirement 15.

**Q. Are there any additional adjustments anticipated in next year's EBA?**

A. Yes, next year's EBA will include an adjustment for the situs assignment of a Utah resource. The Utah Subscriber Solar resource reached commercial operation December 30, 2016, but metered generation data was not available before the year-end accounting close. Therefore, the purchased power costs associated with the last two days of December will be booked in 2017 and included in the 2018 EBA. The costs associated with the Utah Subscriber Solar resource included in the 2017 EBA are for test energy.

**Q. What allocation methodology did the Company use to calculate the EBA Deferral Account balance?**

A. The settlement stipulation in the 2014 GRC set the Base NPC effective September 1, 2014 using the Commission Order Method which was originally approved by the Commission in Docket No. 09-035-15. The Base NPC and Commission Order Method were detailed in Exhibit A of the stipulation in the 2014 GRC. Attached Exhibit RMP___(MGW-1) calculates the EBA deferral using the Commission Order Method for the entire Deferral Period.

**Q. Has the Company calculated the EBA deferral using any other allocation methods?**

A. No. Consistent with the stipulation in the 2014 GRC, beginning September 2014 only the Commission Order Method is used.

**Q. Does the calculation of the EBA deferral include carrying charges?**

A. Yes. In accordance with the Commission’s orders dated March 2, 2011 and February 16, 2017 in Docket No. 09-035-15, carrying charges accrue on the monthly EBA deferral at an annual rate of six percent. Carrying charges accrue monthly during the Deferral Period, the review period, and will continue to accumulate during the collection period.

**Q. Please describe the impact of the special contract customer in the EBA.**

A. The special contract customer pays rates specified in the contract and is not subject to new EBA rates approved on or after December 1, 2016. The NPC associated with serving the special contract customer are embedded in the Actual NPC. As Utah tariff customers benefit from the special contract remaining on the Company’s system and paying a portion of the total revenue requirement, the EBA deferral amount associated with the special contract customer is shared among Utah tariff customers. Additionally, a certain portion of the sales to the special contract customer are at a price different than NPC in base rates, and an adjustment is made to the EBA in which the Utah tariff customers share the variance between the contract price and Base NPC with the Company.

**Q. Please describe the adjustment for sales made to a special contract customer.**

A. Beginning December 1, 2016, per the stipulation in Docket No. 16-035-33, the EBA includes an adjustment for certain sales made to the special contract customer. The adjustment calculates monthly the difference between the average monthly contract price paid and NPC in base rates ("Special Contract Differential"). The Special Contract Differential is then multiplied by the MWh sales to the special contract customer to calculate the dollar amount of the variance. The difference is then subject to a symmetrical deadband of $350,000; however, since the special contract is effective for only one month of the deferral period (December 2016), the deadband was adjusted to one twelfth of $350,000 or $29,167. Tariff customers will receive a refund of approximately $0.2 million.

**Impact of participating in the EIM**

**Q. Are the actual benefits from participating in the EIM with CAISO included in the EBA deferral?**

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. Financially binding EIM operation went live November 1, 2014, and all net benefits arising from EIM operation from January 1, 2016 to December 31, 2016 are included in the 2017 EBA deferral.

**Q. Has the Company quantified the benefits realized during 2016 from participating in the EIM?**

A. Yes, the Company has calculated the EIM inter-regional benefit, i.e. the margin realized on EIM imports and exports. The Company's EIM inter-regional benefit for the deferral period was approximately $19.5 million.

**Q. How does the Company calculate its actual EIM benefits?**

A. Using actual information from the EIM, including five and fifteen-minute pricing, the

Company identifies the incremental resource that could have facilitated the transfer to an adjacent EIM area or the CAISO in each five-minute interval. The benefit is then calculated as the difference between the revenue received less the expense of generation assumed to supply the transfer. In the event of an import, the benefit is equal to the cost of the import minus the avoided expense of the generation that would have otherwise been dispatched.

**Q. What are the estimated 2016 EIM benefits as reported by CAISO?**

A. CAISO publishes quarterly EIM Benefit Reports ("CAISO Benefit Reports") estimating the benefits realized through EIM operation for each entity that participates in the EIM. The CAISO Benefit Reports estimated EIM benefits attributable to PacifiCorp of approximately $45.5 million on a total-company basis for the deferral period. In comparison, the CAISO estimated benefits for the prior year deferral period were approximately $26.2 million on a total-company basis. The benefits estimated for PacifiCorp in the CAISO Reports include the benefits of EIM operation due to more efficient dispatch (both inter- and intra-regional), reduced renewable energy curtailment, and reduced flexibility reserves.

**Q. What is the difference between the EIM benefits estimated by CAISO and the inter-regional EIM benefits calculated by the Company?**

A. The EIM benefits are embedded in the Actual NPC through lower fuel and purchased power costs. However, the Company is able to calculate the margin realized on its EIM imports and exports, the inter-regional benefit. In its quarterly EIM Benefit Report, CAISO estimates all the benefits of participating in the EIM, including intra-regional dispatch savings (optimizing the resources in PacifiCorp's two BAAs), inter-regional dispatch savings (transacting with other EIM participants), reduced renewable energy curtailment and flexibility reserve savings (reduced reserves due to diversity across the EIM footprint).

The CAISO calculation utilizes a counterfactual scenario that is built to mimic the more manual dispatch process PacifiCorp utilized in actual operations prior to participation in the EIM. Based on the subjectivity of the counterfactual scenario, the EIM benefits reports by CAISO are presented as an estimate.

**Deferral Period Results**

**Q. Please describe the Base EBAC the Company used to calculate the amount to be deferred during the Deferral Period.**

A. The Base EBAC for the 2017 EBA was set in the 2014 GRC and became effective September 1, 2015. Base NPC used a test period of 12 months from July 2014 through June 2015 and set total-company Base NPC at $1.491 billion and wheeling revenue at $97 million.

**Q. Please describe Table 2 and the line items making up the difference between Actual NPC and Base NPC.**

A. Table 2 displays the Base NPC approved by the Commission for the Deferral Period. The remainder of Table 2 is a breakout of the difference between Actual NPC and Base NPC, by cost category, on a total-company basis. The differences by category in Table 2 result from comparing Actual NPC to the Base NPC effective during the Deferral Period.

**Table 2**

**Total Company Net Power Cost Reconciliation**

| | TOTAL |
|---|---|
| **Utah Base NPC** | **1,491** |
| | |
| Increase/(Decrease) to NPC: | |
| Wholesale Sales Revenue | 216 |
| Purchased Power Expense | (115) |
| Coal Fuel Expense | (92) |
| Natural Gas Expense | (22) |
| Wheeling and Other Expense | (18) |
| **Total Increase/(Decrease)** | **(31)** |
| 2014 GRC Settlement Adjustment | 3 |
| **Total Company NPC Difference** | **(28)** |
| | |
| **Adjusted Actual NPC** | **1,463** |

**Q. Is the Deferral Period aligned with the test period used in the 2014 GRC?**

A. No. The 2014 GRC test period (July 2014 through June 2015) used to set the Base EBAC does not align with the Deferral Period. To calculate the EBA deferral, the months in the deferral period are compared to the same months from Base NPC in effect at the time. As a result, in this EBA filing, July 2016 Actual NPC is compared against July 2014 Base NPC to calculate the deferrable amount. Actual NPC is compared to a forecast that is two years out of sync for the months of July through December and one year out of sync for the months of January through June.

**Differences in NPC**

**Q. Notwithstanding the issues of test period timing, please describe the primary differences between Actual NPC and Base NPC.**

A. From an accounting perspective, and as shown in Table 2, Actual NPC were lower than Base NPC due to a $115 million reduction in purchased power expense, $92 million reduction in coal fuel expense, $22 million reduction in natural gas expense, and an $18 million reduction in wheeling and other expenses. These reduced expenses were partially offset by a $216 million reduction in wholesale sales revenues.

**Q. Please explain what contributed to the reduction in wholesale sales revenue.**

A. The decline in wholesale sales revenues relative to Base NPC was a combination of a reduction in the wholesale sales volumes of market transactions (represented in GRID as short-term firm and system balancing sales), lower market prices, and expired contracts.

Revenue from market transactions is approximately $178 million lower than Base NPC due to lower market prices and lower volume of market sales transactions. The average price of actual market sales transactions was $14.09/MWh, or 36 percent, lower than the average price in Base NPC. Actual wholesale market volumes were 2,413 GWh, or 29 percent, lower than the Base NPC.

Additionally, long-term wholesale sales contracts with Shell and Sacramento Municipal Utility District (“SMUD”) were included in Base NPC but have since expired. Expiration of these contracts accounted for $10.3 million reduction in wholesale sales revenue and a 305 GWh reduction in sales volume.

**Q. Please explain the decrease in purchased power expenses.**

A. The reduction in purchased power expense was largely due to a decrease in both long-term purchase power contracts and market purchases. The expiration of the Hermiston purchase power agreement (“PPA”) and the Georgia-Pacific Camas contract resulted in lower purchased power costs of $62.7 million, and lower contract volumes with Deseret accounted for $8 million of the reduction. The decrease was partially offset by

$38.9 million from 15 new large qualifying facility ("QF") contracts that were not included in Base NPC and a PPA with Utah Associated Municipal Power Systems ("UAMPS") the Company acquired with its addition of Eagle Mountain, Utah into its service territory.

Expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) accounted for $71 million of the reduction of purchased power costs. Actual market purchases were 332 GWh (seven percent) lower than Base NPC and the average price of actual market purchases transactions was $13.13/MWh (43 percent) lower than Base NPC.

**Q. Please explain the decrease in wheeling expenses.**

A. Actual long-term wheeling contracts decreased by approximately $16.5 million when compared to Base NPC mainly due to expired wheeling contracts. This was partially offset by an increase of $1.5 million of short-term wheeling expenses.

**Q. Please describe the changes in natural gas fuel expense.**

A. The total natural gas fuel expense in Actual NPC decreased by $22 million compared to Base NPC. The main driver of the reduction is the average cost of natural gas generation decreased from $39.73/MWh in Base NPC to $26.00/MWh (35 percent) in the Deferral Period. Reduced costs were partially offset by an increase in natural gas generation volume of 2,859 GWh (41 percent) above Base NPC during the Deferral Period.

**Q. Please discuss the changes in coal fuel expense.**

A. The main driver in the decrease of coal fuel expense is that coal generation volume decreased 6,058 GWh (14 percent) compared to Base NPC which includes lost generation from the retirement of the Carbon plant that was included in Base NPC. Additionally, the average cost of coal generation at the Hunter and Huntington plants were down approximately ten percent and one percent, respectively, compared to Base NPC due to the closure of the Deer Creek mine. The overall decrease in coal fuel expense was partially offset by a slight increase in the average cost of coal generation for the entire coal fleet, which was $19.77/MWh in Base NPC compared to $20.54/MWh in the Deferral Period.

**Jim Bridger Coal Costs**

**Q. Please explain the changes in the coal fuel expense at Jim Bridger compared to the deferral period.**

A. The total coal fuel expense at the Jim Bridger plant was approximately $2.8 million higher than Base NPC, however generation was 1,935 GWh lower. The average cost of generation at Jim Bridger increased $6.01/MWh, or 26 percent, compared to Base NPC. The main driver in the increase of the average cost of coal generation at Jim Bridger is the increase in coal costs which are $48.2 million higher than the coal costs used in Base NPC. Third party coal costs increased by $4.55 per ton, or $7.2 million, and Bridger Coal Company ("BCC") mine costs increased by $13.90 per ton, or $41.0 million.

**Q. Please explain the cost increase in third party delivered coal costs.**

A. The $7.2 million increase is primarily due to pricing under the new Black Butte mine contract that began in 2015 replacing the prior Black Butte coal contract that terminated the first quarter of 2015. The Company entered into the new Black Butte mine contract after issuing a Request for Proposals (RFP) in June 2014 to determine the least cost fuel replacement option.

**Q. Please describe the change in BCC coal costs relative to the deferral period.**

A. BCC costs increased by approximately $41.0 million due to the following reasons: 1) lower British thermal unit ("Btu") content of coal, $4.2 million; 2) spreading costs over the reduced volume of tons produced, $16.7 million; 3) abandonment cost of the Joy Longwall, $12.5 million; and 4) costs of the Joy Longwall recovery efforts, $7.6 million.

**Q. Please explain why coal with a lower Btu content increases coal costs.**

A. The Btu content of coal is positively correlated to the amount of energy produced from burning the coal; the higher the Btu content, the more energy the coal produces when burned. Because the actual Btu content of BCC coal was lower than the Btu content of BCC coal in Base NPC, it was necessary to burn higher quantities of BCC coal than would have been burned had the actual Btu content equaled the Btu content in Base NPC.

**Q. Please explain how the decreased generation at Jim Bridger impacted BCC's costs.**

A. Generation decreased at the Jim Bridger plant by 19 percent compared to Base NPC resulting in less coal being burned. As seen in Table 3 below, coal deliveries from third parties increased compared to Base NPC resulting in fewer deliveries from BCC. BCC deliveries decreased from 4.1 million tons in the base period to 2.8 million tons in 2016, a reduction of 32 percent, and BCC production decreased from 3.7 million tons in the base period to 2.4 million tons in 2016, a reduction of 34 percent. Lower production levels at BCC increases the BCC cost per ton as costs are spread over fewer tons of coal. Notably, if the Btu content of BCC coal would have been higher, less BCC coal would have been needed to produce the actual Jim Bridger generation.

**Table 3**

| | Tons - PacifiCorp Portion | | | | | |
|---|---|---|---|---|---|---|
| | Bridger Plant Deliveries | | | Bridger Mine Production | | |
| millions | 2016 Actuals | Utah GRC (7/14 - 6/15) | Variance | 2016 Actuals | Utah GRC (7/14 - 6/15) | Variance |
| Third Party Sources | 1.6 | 1.4 | 0.2 | | | |
| Bridger Coal | 2.8 | 4.1 | (1.3) | 2.4 | 3.7 | (1.2) |
| *Surface Mine* | *1.7* | *1.0* | *0.7* | *1.6* | *0.9* | *0.7* |
| *Underground Mine* | *1.1* | *3.1* | *(2.0)* | *0.8* | *2.7* | *(2.0)* |
| Jim Bridger Plant Total | 4.4 | 5.5 | (1.1) | | | |

**Q. Please describe the costs associated with the Joy Longwall.**

A. During mining operations at the end of December 2015, a section of panels in the Joy Longwall became stuck soft claystone material due to difficult geological conditions. Significant efforts were made by BCC to return the Joy Longwall to operations in 2016; however, due to unsafe working conditions, the Joy Longwall was ultimately abandoned. Included in the 2017 EBA is the Company's portion of the Joy Longwall recovery and abandonment costs. The recovery costs are the expenses incurred in the effort to return the Joy Longwall to operations. The abandonment costs include the net book value (cost of the asset less accumulated depreciation) of the lost asset, longwall related construction work in process ("CWIP"), material and supply ("M&S") inventory items, and deferred longwall costs.

**Q. Is this the longwall that the Company sold to BCC at the time of the Deer Creek mine closure?**

A. Yes. In an arm's length transaction, the Company sold the Joy Longwall to BCC in September 2015 for the appraised value. The sale of the Joy Longwall reduced the Deer

Creek amortization expense which is included in the 2017 EBA.

**Q. What were the geological conditions that led to the Joy Longwall becoming stuck?**

A. Exhibit RMP___(MGW-3) is a depiction (not to scale) of the mining conditions of the longwall panel, or section of the mine, where the Joy Longwall was stopped by adverse geologic conditions. In Exhibit RMP___(MGW-3) the green line is the top of the coal seam and the pink line is the bottom. Underneath the coal seam is a layer of hard sandstone which is the mine floor. This sandstone layer, or mine floor, varies in depth of approximately one to three feet at any given spot in the longwall panel, and underneath the mine floor is soft claystone material. During operation of the Joy Longwall, the coal seam thinned and undulations, or structural rolls, in the floor became more pronounced and frequent. The Joy Longwall crew attempted to navigate through this area and the soft claystone material under the mine floor became exposed. This is shown in Exhibit RMP___(MGW-3) as the dashed portion of the pink line.

**Q. What actions were taken to climb above the claystone material and place the Joy Longwall back on the mine floor or hard sandstone layer?**

A. The Joy Longwall crew attempted to climb onto the hard sandstone layer by changing the cutting profile of the Joy Longwall. However, the shearer (the part of the longwall that cuts into the coal seam) was unable to operate because it was colliding with other parts of the Joy Longwall. The lack of clearance limited the longwall crew's ability to reestablish a hard, competent floor.

**Q. Did other issues complicate Joy Longwall mining efforts?**

A. Yes. Other issues include mechanical downtime on the shearer equipment and underground conveying system, extreme weather conditions freezing surface coal transfer facilities, poor quality mine floor and deteriorating mine roof conditions. Collectively, these issues impeded the Joy Longwall's ability to climb out of the claystone material.

**Q. Please describe efforts to advance the Joy Longwall and resume coal production activities.**

A. Efforts to climb out of the soft claystone material and reestablish competent roof conditions included pumping foam, tech seal and grout in the area above the Joy Longwall, installing supports beneath the Joy Longwall, freezing the soft claystone material, and injecting bonding agents into floor and roof.

**Q. Were the efforts to stabilize deteriorating section conditions and advance the longwall system successful?**

A. No. None of the efforts described above were able to successfully provide the overall floor stability required to advance the Joy Longwall. Ultimately, working conditions became unsafe and a decision to terminate Joy Longwall recovery efforts was made in early October 2016 with the abandonment costs booked in September 2016.

**Q. Why were such efforts made to advance the Joy Longwall and resume production activities?**

A. First, the Joy Longwall was a valuable asset and the Company felt it was prudent to give its best efforts to return the Joy Longwall to production. The mining conditions encountered in the front part of the longwall panel were encouraging, resulting in favorable productivity rates and coal quality, and the longwall panel had approximately 400,000 tons remaining to be mined. Aside from the monetary value, the Joy Longwall provided operational benefits because it has a lower minimum operating height than the DBT Longwall. This operating flexibility enabled the Joy Longwall to extract a higher quality product in areas with thinning coal seams relative to the DBT Longwall.

**Q. Does this conclude your direct testimony?**

A. Yes.

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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Michael G. Wilding
Calculation of the EBA Deferral

March 2017

**Utah Energy Balancing Account Mechanism**
**January 1, 2016 - December 31, 2016**
**Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor)**

| Line No. | | Reference | Jan-16 | Feb-16 | Mar-16 | Apr-16 | May-16 | Jun-16 | Jul-16 | Aug-16 | Sep-16 | Oct-16 | Nov-16 | Dec-16 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Actual: Utah Allocated** | | | | | | | | | | | | | | |
| 1 | NPC | (2.1) | $ 55,141,142 | $ 48,989,820 | $ 48,820,855 | $ 44,298,160 | $ 47,606,589 | $ 60,371,562 | $ 62,273,780 | $ 62,648,923 | $ 58,555,825 | $ 46,710,058 | $ 45,102,296 | $ 56,757,273 | $ 637,276,283 |
| 2 | Wheeling Revenue | (4.1) | $ (3,493,265) | $ (3,234,337) | $ (3,094,790) | $ (3,251,908) | $ (3,313,836) | $ (3,963,432) | $ (4,108,346) | $ (3,907,511) | $ (3,967,994) | $ (3,408,578) | $ (2,998,650) | $ (5,377,300) | $ (44,119,946) |
| 3 | Total | ∑ Lines 1:2 | $ 51,647,877 | $ 45,755,484 | $ 45,726,066 | $ 41,046,253 | $ 44,292,752 | $ 56,408,129 | $ 58,165,433 | $ 58,741,412 | $ 54,587,831 | $ 43,301,480 | $ 42,103,646 | $ 51,379,973 | $ 593,156,337 |
| 4 | Jurisdictional Sales | (5.2) | 2,063,133 | 1,867,959 | 1,794,840 | 1,756,553 | 1,839,831 | 2,229,623 | 2,444,057 | 2,297,435 | 1,886,534 | 1,839,501 | 1,822,867 | 2,135,055 | 23,977,388 |
| 5 | Actual Utah $/MWh | Line 3 / Line 4 | **$ 25.03** | **$ 24.49** | **$ 25.48** | **$ 23.37** | **$ 24.07** | **$ 25.30** | **$ 23.80** | **$ 25.57** | **$ 28.94** | **$ 23.54** | **$ 23.10** | **$ 24.06** | **$ 24.74** |
| | **Base: Utah Allocated** | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | 26.56 | |
| 6 | NPC | (3.1) | $ 52,951,274 | $ 49,340,602 | $ 52,632,441 | $ 48,247,358 | $ 49,229,412 | $ 51,883,412 | $ 60,534,576 | $ 60,895,340 | $ 49,740,054 | $ 49,325,488 | $ 49,731,889 | $ 53,488,153 # | $ 628,000,000 |
| 7 | Wheeling Revenue | (4.1) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) | $ (3,422,346) # | (41,068,157) |
| 8 | Total | ∑ Lines 6:7 | $ 49,528,928 | $ 45,918,256 | $ 49,210,095 | $ 44,825,011 | $ 45,807,066 | $ 48,461,065 | $ 57,112,230 | $ 57,472,993 | $ 46,317,708 | $ 45,903,142 | $ 46,309,543 | $ 50,065,807 | $ 586,931,843 |
| 9 | Jurisdictional Sales | | 2,020,370 | 1,829,854 | 1,902,391 | 1,832,113 | 1,821,070 | 1,903,419 | 2,191,141 | 2,157,502 | 1,865,837 | 1,829,381 | 1,877,678 | 2,013,529 | 23,244,285 |
| 10 | Base Utah $/MWh | Line 8 / Line 9 | **$ 24.51** | **$ 25.09** | **$ 25.87** | **$ 24.47** | **$ 25.15** | **$ 25.46** | **$ 26.07** | **$ 26.64** | **$ 24.82** | **$ 25.09** | **$ 24.66** | **$ 24.86** | **$ 25.25** |
| | **Deferral:** | | | | | | | | | | | | | | |
| 11 | $/ MWH Differential | Line 5 - Line 10 | $ 0.52 | $ (0.60) | $ (0.39) | $ (1.10) | $ (1.08) | $ (0.16) | $ (2.27) | $ (1.07) | $ 4.11 | $ (1.55) | $ (1.57) | $ (0.80) | $ (0.51) |
| 12 | Total Deferrable | Line 4 * Line 11 | $ 1,070,623 | $ (1,118,994) | $ (701,941) | $ (1,930,087) | $ (1,986,213) | $ (358,086) | $ (5,539,051) | $ (2,459,220) | $ 7,756,330 | $ (2,855,610) | $ (2,854,067) | $ (1,707,554) | $ (12,683,869) |
| 13 | Incremental EBA Deferral at 70% Sharing | Line 12 * 70% | **$ 749,436** | **$ (783,296)** | **$ (491,359)** | **$ (1,351,061)** | **$ (1,390,349)** | | | | | | | | **$ (3,266,628)** |
| 14 | Incremental EBA Deferral Beginning June 1, 2016 | Line 12 | | | | | | **$ (358,086)** | **$ (5,539,051)** | **$ (2,459,220)** | **$ 7,756,330** | **$ (2,855,610)** | **$ (2,854,067)** | **$ (1,707,554)** | **$ (8,017,258)** |
| 15 | Coal Fuel Savings from Deer Creek Mine Closure not Subject to Sharing | Workpaper (6.1) | $ (173,509) | $ (273,506) | $ (97,632) | $ (13,065) | $ (177,624) | | | | | | | | $ (735,336) |
| 16 | Incremental Non-Fuel FAS 106 Savings | Workpaper (6.1) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (245,155) | $ (2,941,860) |
| | **Adjustment for Sales to Special Contract Customer** | | | | | | | | | | | | | | |
| 17 | Special Contract Sales (MWh) | Workpaper (7.1) | | | | | | | | | | | | 58,294 | 58,294 |
| 18 | Average Monthly Contract Price ($/MWh) | Workpaper (7.1) | | | | | | | | | | | | $ 30.51 | |
| 19 | Base NPC in Rates ($/MWh) | Line 6 / Line 9 | | | | | | | | | | | | $ 26.56 | |
| 20 | Special Contract Differential | Line 19 - Line 18 | | | | | | | | | | | | $ (3.94) | |
| 21 | Special Contract Customer Adjustment Subject to Deadband | Line 20 * Line 17 | | | | | | | | | | | | $ (229,884) | $ (229,884) |
| 22 | Symmetrical Deadband | Docket 16-035-33 | | | | | | | | | | | | $ (29,167) | $ (29,167) |
| 23 | Total Special Contract Adjustment | Line 21 - Line 22 | | | | | | | | | | | | $ (200,718) | $ (200,718) |
| 24 | Total Incremental EBA Deferral | ∑ Lines 13:16 and Line 23 | **$ 330,772** | **$ (1,301,956)** | **$ (834,146)** | **$ (1,609,281)** | **$ (1,813,128)** | **$ (603,241)** | **$ (5,784,206)** | **$ (2,704,375)** | **$ 7,511,175** | **$ (3,100,765)** | **$ (3,099,222)** | **$ (2,153,427)** | **$ (15,161,800)** |
| | **Energy Balancing Account:** | | | | | | | | | | | | | | |
| 25 | Monthly Interest Rate (6% Annual) | Note 1 | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | 0.50% | |
| 26 | Beginning Balance | Prior Month Line 29 | $ - | $ 331,599 | $ (971,954) | $ (1,813,045) | $ (3,435,415) | $ (5,270,253) | $ (5,901,353) | $ (11,729,526) | $ (14,499,309) | $ (7,041,853) | $ (10,185,579) | $ (13,343,477) | $ - |
| 27 | Incremental Deferral | Line 24 | $ 330,772 | $ (1,301,956) | $ (834,146) | $ (1,609,281) | $ (1,813,128) | $ (603,241) | $ (5,784,206) | $ (2,704,375) | $ 7,511,175 | $ (3,100,765) | $ (3,099,222) | $ (2,153,427) | $ (15,161,800) |
| 28 | Interest | Line 25 * ( Line 26 + 50% x Line 27) | $ 827 | $ (1,597) | $ (6,945) | $ (13,088) | $ (21,710) | $ (27,859) | $ (43,967) | $ (65,409) | $ (53,719) | $ (42,961) | $ (58,676) | $ (72,101) | $ (407,205) |
| 29 | **Ending Balance** | ∑ Lines 26:28 | **$ 331,599** | **$ (971,954)** | **$ (1,813,045)** | **$ (3,435,415)** | **$ (5,270,253)** | **$ (5,901,353)** | **$ (11,729,526)** | **$ (14,499,309)** | **$ (7,041,853)** | **$ (10,185,579)** | **$ (13,343,477)** | **$ (15,569,005)** | **$ (15,569,005)** |
| 30 | Deer Creek Mine Amortization | Workpaper (6.1) | | | | | | | | | | | | | **$ 9,155,405** |
| 31 | Accrued Interest through April 30, 2017 | ∑ Lines 29:30 * (1 + 1.06% / 12) ^ 4 - ∑ Lines 29:30 | | | | | | | | | | | | | $ (129,237) |
| 32 | **Requested EBA Recovery** | ∑ Lines 29:31 | | | | | | | | | | | | | **$ (6,542,837)** |

Note:
1 Docket No. 09-035-15, March 2, 2011 Report and Order, Page 79 and
Docket No. 15-035-69, January 20, 2016 Order, Page 16 and
Docket No. 09-035-15, February 16, 2017 Order, Page 15

Rocky Mountain Power
Exhibit RMP___(MGW-2)
Docket No. 17-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Michael G. Wilding
New EBA SAP Accounts

March 2017

**FERC and SAP Accounts Included in EBA**

Asteriks denote accounts used in 2016 that should be added to the Schedule 94 tariff sheet

| Category | FERC Account | SAP Account | Description | |
|---|---|---|---|---|
| FERC Account 501 - Fuel | 5011000 | 515100 | Coal Consumed for Generation | |
| | 5013500 | 505917 | InterCo Natural Gas Consumed- Kern River | |
| | 5013500 | 515200 | Natural Gas Consumed for Generation | |
| | 5013500 | 515220 | Natural Gas Swaps - Gains/Losses | |
| | 5013500 | 515250 | Natural Gas Expense - Accrual | |
| | 5013500 | 515270 | Natural Gas Swaps-Gain/Loss-Accrual | |
| FERC Account 447 - Sales for Resale | 4471300 | 301405 | Firm Sales | |
| | 4471400 | 301406 | Short-term Firm Whls | |
| | 4475000 | 301408 | Off-System Non Firm | |
| | 4471400 | 301410 | Trading Sales Netted | |
| | 4471400 | 301411 | Bookout Sales Netted | |
| | 4471400 | 302751 | I/C ST Firm Whls-Sie | |
| | 4471400 | 302752 | I/C S-T Firm Wholesale Sales-Nevada Pwr | |
| | 4471400 | 302771 | I/C Line Loss Trading Revenue-Sierra Pac | |
| | 4471400 | 302772 | I/C Line Loss-Nevada | |
| | 4471400 | 303028 | Line Loss W/S Trdg R | |
| | 4471400 | 303109 | Transm Line Loss Rev - Subject to Refund | |
| | 4476100 | 304101 | Bookouts Netted-Gain | |
| | 4476200 | 304201 | Trading Netted-Gains | |
| FERC Account 555 - Purchased Power | 5556100 | 304111 | Bookouts Netted - Loss | |
| | 5556200 | 304211 | Trading Netted-Losses | |
| | 5552500 | 505190 | OR Solar Incentive Purchases | |
| | 5552500 | 505206 | Other Egy Purch, Int | |
| | 5555500 | 505207 | IPP Egy Purch | |
| | 5556300 | 505214 | Firm Energy Purchases | |
| | 5556700 | 505215 | Post-Merg Imb Charge | |
| | 5556400 | 505218 | Firm Demand Purchases | |
| | 5556700 | 505220 | Trading Purch Netted | |
| | 5556700 | 505221 | Bookout Purchases Ne | |
| | 5555900 | 505224 | Short-Term Firm Wholesale Purchases | |
| | 5552600 | 505351 | Elec Swaps-Gain/Loss | |
| | 5555900 | 505931 | I/C ST Firm Pur-Sier | |
| | 5555900 | 505932 | I/C ST Firm Pur-Nev | |
| | 5556700 | 505969 | Transm Imbalance - Subject to Refund | |
| | 5556700 | 546520 | Oprating Resrves Exp | |
| | 5556710 | 508001 | EIM Exp - FMM IIE: CAISO to Pac | |
| | 5556710 | 508003 | EIM Exp - FMM Assess: Pac Trans to C&T | |
| | 5556710 | 508011 | EIM Exp - RTD IIE: CAISO to Pac | |
| | 5556710 | 508013 | EIM Exp - RTD Assess: Pac Trans to C&T | |
| | 5556710 | 508015 | EIM Exp - GHG Em Cost Rev: CAISO to Pac | |
| | 5556710 | 508021 | EIM Exp - UIE (Load): CAISO to Pac | |
| | 5556710 | 508023 | EIM Exp - UIE (Load): Pac Trans to C&T | |
| | 5556710 | 508031 | EIM Exp - UIE (Gen): CAISO to Pac | |
| | 5556710 | 508033 | EIM Exp - UIE (Gen): Pac Trans to C&T | |
| | 5556710 | 508041 | EIM Exp - Daily Rounding Adj: w/CAISO | |
| | 5556710 | 508051 | EIM Exp - O/U Sched Charge: w/CAISO | |
| | 5556710 | 508053 | EIM Exp - O/U Sched Alloc: w/CAISO | |
| | 5556710 | 508054 | EIM Exp-O/U Sched Alloc: PAC to TC | * |
| | 5556710 | 508061 | EIM Exp-Ancil Svc Upw Neutral: w/CAISO | |
| | 5556710 | 508062 | EIM Exp-Spinning Reserve Oblig: w/CAISO | |
| | 5556710 | 508063 | EIM Exp-Spin Reserve Neutral: w/CAISO | |
| | 5556710 | 508064 | EIM Exp-Non-Spin Reserve Oblig: w/CAISO | |
| | 5556710 | 508065 | EIM Exp-Non-Spin Reserve Neut: w/CAISO | |
| | 5556710 | 508066 | EIM Exp - Excess Cost Neutral: w/CAISO | |
| | 5556710 | 508071 | EIM Exp - RT Bid Cost Recovery: w/CAISO | |
| | 5556710 | 508091 | EIM Exp - Flexible Ramp Cost: w/CAISO | |
| | 5556710 | 508095 | EIM Exp-Flex RampUp Cap Pay: w/CAISO | |
| | 5556710 | 508096 | EIM Exp-Flex RampUp Cap No Pay: w/CAISO | |
| | 5556710 | 508101 | EIM Exp-RT Unaccounted Energy: w/CAISO | |
| | 5556710 | 508111 | EIM Exp-RT Imb Energy Offset: w/CAISO | |
| | 5556710 | 508121 | EIM Exp-RT BCR EIM Alloc: CAISO to Pac | |
| | 5556710 | 508125 | EIM Exp-RTM BCR EIM Set: CAISO to Pac | |
| | 5556710 | 508131 | EIM Exp-RT Congestion OS: CAISO to Pac | |
| | 5556710 | 508141 | EIM Exp-RT Marginal Loss: CAISO to Pac | |
| | 5556710 | 508142 | EIM Exp-Neutrality Adjust CAISO to Pac | * |
| | 5556710 | 508151 | EIM Exp-7070 FRP Forecast Mvmt | * |
| | 5556710 | 508152 | EIM Exp-7076 FRP Forecast Mvmt Alloc | * |
| | 5556710 | 508153 | EIM Exp-7071 FRP Daily Up Uncert | * |
| | 5556710 | 508154 | EIM Exp-7081 FRP Daily Down Uncert | * |
| | 5556710 | 508155 | EIM Exp-7077 FRP Daily Up Uncert Alloc | * |
| | 5556710 | 508156 | EIM Exp-7078 FRP Month Up Uncert Alloc | * |
| | 5556710 | 508157 | EIM Exp-7087 FRP Daily Down Uncert Allo | * |
| | 5556710 | 508158 | EIM Exp-7088 FRP Month Down Uncert Allo | * |
| | 5556700 | 546516 | CA GHG Wholesale Obligation | |
| | 5556710 | 508132 | EIM Exp-RT Congestion | |
| | 5556710 | 508122 | EIM Exp-RT BCR EIM | |
| | 5556710 | 508112 | EIM Exp-RT Imb Energy Offset | |
| | 5556710 | 508092 | EIM Exp - Flexible Ramp Cost | |
| | 5556710 | 508081 | EIM Exp-IFM Loss Surplus Credit w/CAISO | |
| | 5556710 | 508052 | EIM Exp - O/U Sched Alloc: w/CAISO | |

**FERC and SAP Accounts Included in EBA**

Asteriks denote accounts used in 2016 that should be added to the Schedule 94 tariff sheet

| Category | FERC Account | SAP Account | Description |
|---|---|---|---|
| FERC Account 565 - Wheling Expense | 5651000 | 506010 | Short-Term Firm Whee |
| | 5652500 | 506020 | Non-Firm Wheeling Ex |
| | 5654600 | 506050 | Firm Wheeling Exp |
| | 5650010 | 506801 | EIM Wheeling Exp-GMC |
| | 5650010 | 506802 | EIM Wheeling Exp-GMC |
| | 5651000 | 506911 | I/C S-T Firm Wheeling Exp-Nevada Pwr |
| | 5651000 | 506912 | I/C S-T Firm Wheeling Exp-Nevada Pwr |
| | 5652500 | 506921 | I/C Non-Firm Wheeling Exp-Sierra Pac |
| | 5652500 | 506922 | I/C Non-Firm Wheeling Exp-Nevada Pwr |
| | 5650000 | 546530 | ISO/PX Charges |
| FERC Account 503 - Steam From Other Sources | 5030000 | 515900 | Steam from Other Sources - Geothermal |
| FERC Account 547 - Other Generation | 5471000 | 505917 | InterCo Natural Gas Consumed |
| | 5471000 | 515200 | Natural Gas Consumed for Generation |
| | 5471000 | 515201 | Natural Gas Exp - Under Capital Lease |
| | 5471000 | 515220 | Natural Gas Swaps - Gains/Losses |
| | 5471000 | 505918 | InterCo Natural Gas Accrual-Kern River |
| | 5471000 | 515250 | Natural Gas Expense - Accrual |
| | 5471000 | 515251 | Natural Gas Exp-Capital Lease-Accrual |
| | 5471000 | 515270 | Natural Gas Swaps-Gain/Loss-Accrual |
| FERC Account 456.1 - Revenues from Transmission of Electricity by Others | 4561100 | 301953 | Ancillary Rev Sch 6-Supp (C&T) |
| | 4561100 | 301962 | Ancil Revenue Sch 2-Reactive (Trans) |
| | 4561100 | 301963 | Ancil Revenue Sch 2-Reactive (C&T) |
| | 4561100 | 301964 | Ancil Revenue Sch 3a-Regulation (Trans) |
| | 4561100 | 301966 | Primary Delivery and Distribution Sub Ch |
| | 4561100 | 301967 | Ancillary Revenue Sch 1 - Scheduling |
| | 4561100 | 301968 | Ancillary Rev Sch 3 - Reg&Freq (Transm) |
| | 4561100 | 301969 | Anc Rev Sch 3 - C&T Reg&Freq |
| | 4561100 | 301972 | Ancillary Rev Sch 5&6-Spin&Supp (Transm) |
| | 4561100 | 301973 | Anc Rev Sch 5&6-C&T Spn & Supp |
| | 4561100 | 301974 | Ancil Revenue Sch 3a-Regulation (C&T) |
| | 4561100 | 302831 | I/C Other Wheeling Revenue-Sierra Pac |
| | 4561100 | 302081 | I/C Anc Rev Sch 1-Scheduling-Sierra Pac |
| | 4561100 | 302082 | I/C Anc Rev Sch 1-Scheduling-Nevada Pwr |
| | 4561100 | 302091 | I/C Anc Rev Sch 2-Reactive-Sierra Pac |
| | 4561100 | 302092 | I/C Anc Rev Sch 2-Reactive-Nevada Pwr |
| | 4561100 | 302901 | Use of Facility - Revenue |
| | 4561100 | 302981 | Transmission Resales to Other Parties |
| | 4561100 | 302982 | Transmission Rev-Unreserved Use Charges |
| | 4561100 | 302983 | Prv Rate Ref-Interdepartmental |
| | 4561910 | 302812 | I/C ST Firm Wheeling Revenue-Nevada Pwr |
| | 4561910 | 301926 | Short-Term Firm Wheeling |
| | 4561920 | 301912 | Post-Merger Firm Wheeling Revenue |
| | 4561920 | 301916 | Pre-Merger Firm Wheeling Revenue - PPD |
| | 4561920 | 301917 | Pre-Merger Firm Wheeling Revenue - UPD |
| | 4561920 | 302961 | Transm Cap Re-assign |
| | 4561920 | 302962 | Transm Capacity Re-assignment Contra Rev |
| | 4561920 | 302980 | Transmisson Point-to-Point Revenue |
| | 4561990 | 301913 | Transmission Tariff True-up |
| | 4561930 | 302821 | I/C Non-Firm Wheeling Revenue-Sierra Pac |
| | 4561930 | 302822 | I/C Non-Firm Wheeling Revenue-Nevada Pwr |
| | 4561990 | 302990 | L-T Transm Revenue - Subject to Refund |
| | 4561990 | 305910 | Ancil Revenue Sch 1 - Subject to Refund |
| | 4561990 | 305920 | Ancil Revenue Sch 2 - Subject to Refund |
| | 4561990 | 305930 | Ancil Revenue Sch 3 - Subject to Refund |
| | 4561990 | 305931 | Ancil Revenue Sch 3a - Subject to Refund |
| | 4561930 | 301922 | Non-Firm Wheeling Revenue |
| | 4561100 | 505961 | Transm Imbalance Penalty Revenue-Load |
| | 4561100 | 505963 | Transm Imbalance Penalty Rev-Pt-to-Pt |

Rocky Mountain Power
Exhibit RMP___(MGW-3)
Docket No. 17-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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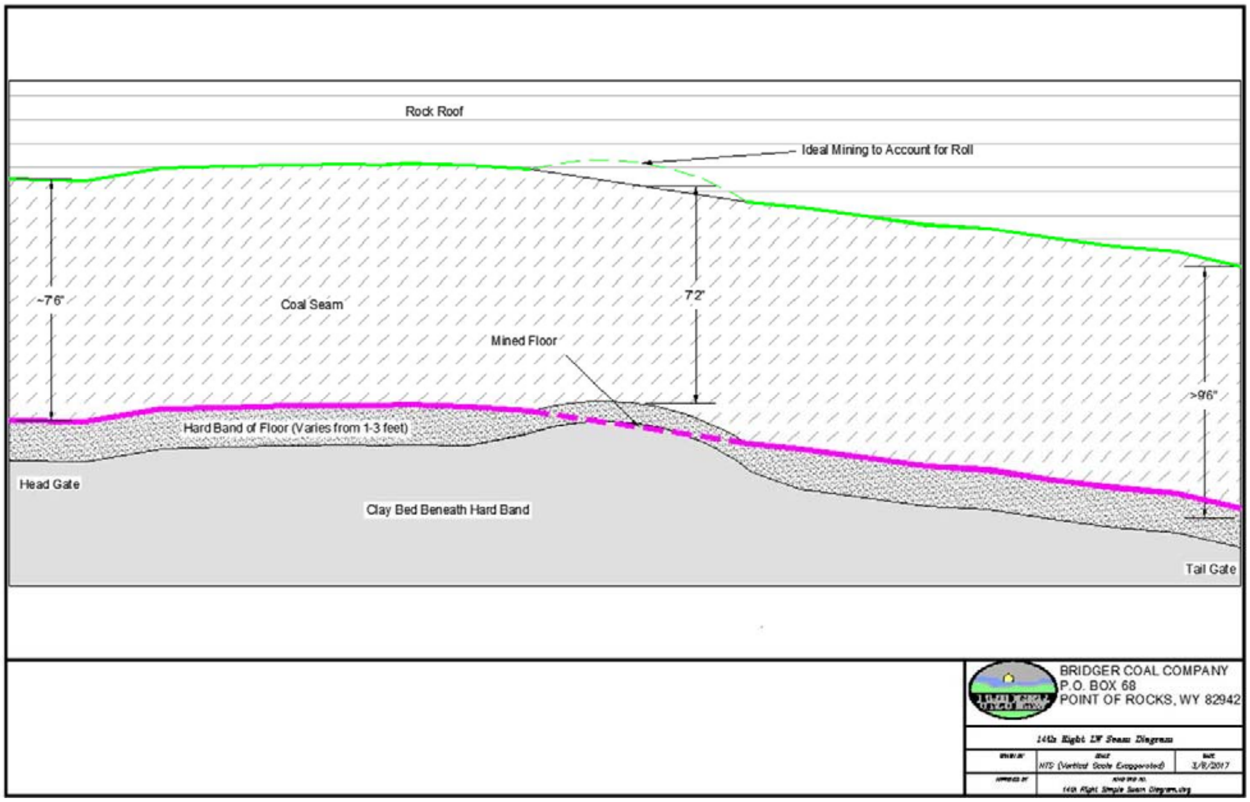
Exhibit Accompanying Direct Testimony of Michael G. Wilding
Conditions at the Time of Joy Longwall Abandonment

March 2017

**Utah Energy Balancing Account Mechanism**
**January 1, 2016 – December 31, 2016**
**Exhibit RMP___(MGW-3)**
**Conditions at the Time of the Joy Longwall Abandonment**



Rocky Mountain Power
Docket No. 17-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Direct Testimony of Robert M. Meredith

March 2017

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

A. My name is Robert M. Meredith. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Manager, Pricing and Cost of Service.

**Qualifications**

**Q. Briefly describe your educational and professional background.**

A. I graduated magna cum laude from Oregon State University in 2004 with a Bachelor of Science degree in Business Administration and a minor in Economics. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for twelve years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over six years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. I assumed my present position in March 2016.

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have previously filed testimony on behalf of the Company in regulatory proceedings in Utah, Washington and California.

**Purpose and Summary of Testimony**

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present and support the Company's proposed rate spread and rates in Schedule 94 to recover the requested Energy Balancing Account ("EBA") deferral amount identified by Company witness Mr. Michael G. Wilding for the 12-months ended December 31, 2016 ("2017 EBA").

**Q. Please summarize the rate impacts for the proposed change to Schedule 94 for this filing.**

A. The change in Schedule 94 is a decrease of $6.5 million, or 0.3 percent. This change is incremental to the current collection level for the 2016 EBA. Exhibit RMP___(RMM-1), page 1, shows the net impact by rate schedule.

**Proposed EBA Rate Spread**

**Q. What is the 2017 EBA deferral amount in this case?**

A. The total 2017 EBA deferral is a $6.5 million credit, as shown in Table 1 of Mr. Wilding's testimony. The Company proposes to credit this amount back to customers over one year with interim rates effective May 1, 2017, consistent with the Commission's order in Docket No. 09-035-15 issued on February 16, 2017 ("EBA Order"). In accordance with the EBA Order, any difference between 2017 EBA credits and the final amount approved by the Commission would be included in new rates, effective May 1, 2018. The Company also proposes continuing the collection of the existing 2016 EBA that went into effect November 1, 2016, until the deferral balance is fully collected. The Company currently estimates the 2016 EBA deferral will be fully recovered around early September 2017.

**Q. How does the Company propose to begin crediting customers for interim rates for the 2017 EBA, while simultaneously collecting the remaining deferral for the 2016 EBA?**

A. For administrative ease, the Company proposes keeping the existing percentage adjustments by rate schedule for the 2016 EBA currently in effect on Schedule 94, but adding another column for the interim adjustments for the 2017 EBA, along with a column that totals both adjustments for each rate schedule. As the balancing account for the 2016 EBA draws closer to a zero balance, the Company proposes to submit an advice filing to cancel the rates adjustments for the 2016 EBA on the date the Company forecasts full collection of the authorized deferral amount. Any amount remaining in the balancing account for the 2016 EBA would be rolled into the new rates to be effective May 1, 2018.

**Q. How does the Company propose to allocate the 2017 EBA deferral balance across customer classes?**

A. The Company proposes to spread the 2017 EBA deferral across customer rate schedules consistent with the NPC Allocators agreed to by the parties and approved by the Commission in the 2014 general rate case, Docket No. 13-035-184 ("2014 GRC"). The allocators and allocations by rate schedule are shown on page 2 in Exhibit RMP___(RMM-1).

**Q. How does the Company propose to allocate the 2017 EBA revenue to those customer classes that were not reflected in the NPC Allocators?**

A. There are two customer classes-Schedule 21 and Schedule 31-that are subject to the EBA but were not included in the Company's cost of service studies in the 2014 GRC and therefore not reflected in the NPC Allocators. For the customer classes, the Company proposes to apply the same percentage change to these customer classes as Schedule 9 consistent with the rate spreads approved in prior EBAs.

**Q. How does the Company propose to allocate the 2017 EBA revenue to Contract Customer 1?**

A. Consistent with the terms of the contract approved by the Public Service Commission of Utah in Docket No. 15-035-81, the 2017 EBA revenue allocation for Contract Customer 1 is based on the overall 2017 EBA percentage to tariff customers in Utah.

**Q. How does the Company propose to collect the 2017 EBA deferral after these adjustments to the NPC Allocators?**

A. The results of the 2017 EBA deferral spread based on the NPC Allocator are then proportionally adjusted for all customer classes to credit a total target amount of $6.5 million.

**Q. What present revenues and billing determinants is the Company proposing to use to allocate the 2017 EBA?**

A. The Company has developed the rate spread using the Commission approved Step 2 present revenues and the billing determinants set forth in the 2014 GRC Stipulation.

**Q. Special Condition 15 of Schedule 73, Subscriber Solar Program Rider - Optional, indicates that the EBA adjustment will no longer apply to participating contract Subscriber Solar Energy Block kWh one year after the Subscriber Solar Program solar resource begins commercial operation. Were the billing determinants for the 2017 EBA adjusted to reflect this situation?**

A. No. The relatively small quantity of energy that would not be subject to the EBA due to the subscriber solar program did not warrant a modification of the billing determinants at this time. As of February 21, 2017, 47,323 megawatt hours (MWh) were subscribed in the program. Since the commercial operation date for the Subscriber

Solar Program solar resource was December 30, 2016, subscribed energy would not be subject to the EBA for roughly 4 out of the 12 months or about 33 percent of the period under which rates would be collected. Thirty-three percent of 47,323 MWh, or about 15,617 MWh represents about one half of one percent of total Utah energy sales during the test period.

**Proposed Rates for Schedule 94**

**Q. How were the proposed Schedule 94 rates developed for each customer class?**

A. Consistent with the EBA Rate Determination provision in Schedule 94, the proposed rates for each customer class were determined by dividing the allocated EBA deferral amount to each rate schedule and applicable contract by the corresponding 2014 GRC Step 2 forecast Power Charge and Energy Charge revenues. The EBA rate is a percentage applied to the monthly Power Charges and Energy Charges.

**Q. Please describe Exhibit RMP___(RMM-2).**

A. Exhibit RMP___(RMM-2) contains the billing determinants and the calculations of the proposed EBA rates in this case.

**Q. Please describe Exhibit RMP___(RMM-3).**

A. Exhibit RMP___(RMM-3) contains the proposed tariff rate revisions for Schedule 94. As mentioned earlier in my testimony, the proposed tariff includes a column for the currently effective adjustments for the collection of the 2016 EBA, a column for adjustments for the proposed interim collection of the 2017 EBA, and a column totaling both for the net adjustment that the Company proposes applying to customer bills beginning May 1, 2017. It also contains a revision to Schedule 94 to reflect changes to the EBA Procedural Schedule shown on page three of the tariff to be consistent with timing prescribed in the EBA Order, and a revision to reflect new SAP accounts used by the Company to track components of net power costs, as discussed by Mr. Wilding.

**Q. Did you include workpapers with this filing?**

A. Yes. Workpapers have been included with this filing that detail the calculations shown in my exhibits.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

Rocky Mountain Power
Exhibit RMP___(RMM-1)
Docket No. 17-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Robert M. Meredith
Table A – Estimate Effect of Proposed Changes

March 2017

**Table A**
**Rocky Mountain Power**
**Estimated Effect of Proposed Changes**
**on Revenues from Electric Sales to Ultimate Consumers in Utah**
**Base Period 12 Months Ending June 2013**
**Forecast Test Period 12 Months Ending June 2015**

| Line No. | Description (1) | Sch No. (2) | No. of Customers Forecast (3) | MWh Forecast (4) | Present Revenue ($000) Base (5) | Present Revenue ($000) EBA (6) | Present Revenue ($000) Net (7) | Proposed Revenue ($000) Base (8) | Proposed Revenue ($000) EBA (9) | Proposed Revenue ($000) Net (10) | Change Base ($000) (11) | Change Base (%) (12) | Change Net ($000) (13) | Change Net (%) (14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Residential** | | | | | | | | | | | | | |
| 1 | Residential | 1,3 | 740,189 | 6,200,666 | $684,505 | $4,038 | $688,543 | $684,505 | $2,145.14 | $686,650 | $0 | 0.0% | ($1,893) | -0.3% |
| 2 | Residential-Optional TOD | 2 | 447 | 3,186 | $351 | $2 | $354 | $351 | $1.10 | $353 | $0 | 0.0% | ($1) | -0.3% |
| 3 | AGA/Revenue Credit | -- | | | $33 | | $33 | $33 | | $33 | $0 | 0.0% | $0 | 0.0% |
| 4 | **Total Residential** | | 740,636 | 6,203,852 | $684,889 | $4,040 | $688,929 | $684,889 | $2,146 | $687,036 | $0 | 0.0% | ($1,894) | -0.3% |
| | **Commercial & Industrial & OSPA** | | | | | | | | | | | | | |
| 5 | General Service-Distribution | 6 | 13,072 | 5,783,806 | $494,681 | $3,569 | $498,251 | $494,681 | $1,889.49 | $496,571 | $0 | 0.0% | ($1,680) | -0.3% |
| 6 | General Service-Distribution-Energy TOD | 6A | 2,276 | 292,031 | $34,227 | $248 | $34,475 | $34,227 | $132.24 | $34,360 | $0 | 0.0% | ($115) | -0.3% |
| 7 | General Service-Distribution-Demand TOD | 6B | 37 | 3,907 | $346 | $2 | $348 | $346 | $1.26 | $347 | $0 | 0.0% | ($1) | -0.3% |
| 8 | *Subtotal Schedule 6* | | 15,385 | 6,079,745 | $529,255 | $3,819 | $533,074 | $529,255 | $2,023 | $531,278 | $0 | 0.0% | ($1,796) | -0.3% |
| 9 | General Service-Distribution > 1,000 kW | 8 | 274 | 2,187,047 | $167,313 | $1,340 | $168,653 | $167,313 | $713.66 | $168,027 | $0 | 0.0% | ($626) | -0.4% |
| 10 | General Service-High Voltage | 9 | 149 | 5,027,436 | $284,876 | $2,960 | $287,837 | $284,876 | $1,585.88 | $286,462 | $0 | 0.0% | ($1,374) | -0.5% |
| 11 | General Service-High Voltage-Energy TOD | 9A | 9 | 42,591 | $3,293 | $34 | $3,327 | $3,293 | $18.10 | $3,311 | $0 | 0.0% | ($16) | -0.5% |
| 12 | *Subtotal Schedule 9* | | 158 | 5,070,026 | $288,169 | $2,994 | $291,163 | $288,169 | $1,604 | $289,773 | $0 | 0.0% | ($1,390) | -0.5% |
| 13 | Irrigation | 10 | 2,784 | 173,133 | $13,210 | $106 | $13,315 | $13,210 | $55.32 | $13,265 | $0 | 0.0% | ($50) | -0.4% |
| 14 | Irrigation-Time of Day | 10TOD | 261 | 16,757 | $1,286 | $10 | $1,296 | $1,286 | $5.39 | $1,291 | $0 | 0.0% | ($5) | -0.4% |
| 15 | *Subtotal Irrigation* | | 3,045 | 189,890 | $14,496 | $116 | $14,611 | $14,496 | $61 | $14,556 | $0 | 0.0% | ($55) | -0.4% |
| 16 | Electric Furnace | 21 | 5 | 4,049 | $476 | $5 | $481 | $476 | $2.59 | $479 | $0 | 0.0% | ($2) | -0.5% |
| 17 | General Service-Distribution-Small | 23 | 82,668 | 1,390,888 | $139,103 | $891 | $139,994 | $139,103 | $465.07 | $139,568 | $0 | 0.0% | ($426) | -0.3% |
| 18 | Back-up, Maintenance, & Supplementary | 31 | 4 | 56,282 | $4,576 | $36 | $4,611 | $4,576 | $19.01 | $4,595 | $0 | 0.0% | ($17) | -0.4% |
| 19 | Contract 1 | -- | 1 | 535,721 | $27,959 | $204 | $28,163 | $27,959 | $110.04 | $28,069 | $0 | 0.0% | ($94) | -0.3% |
| 20 | Contract 2 | -- | 1 | 795,799 | $35,063 | $410 | $35,473 | $35,063 | $217.39 | $35,280 | $0 | 0.0% | ($193) | -0.5% |
| 21 | Contract 3 | -- | 1 | 621,809 | $30,035 | $306 | $30,342 | $30,035 | $306.19 | $30,342 | $0 | 0.0% | $0 | 0.0% |
| 22 | AGA/Revenue Credit | -- | | | $2,928 | | $2,928 | $2,928 | | $2,928 | $0 | 0.0% | $0 | 0.0% |
| 23 | **Total Commercial & Industrial & OSPA** | | 101,542 | 16,931,257 | $1,239,372 | $10,122 | $1,249,494 | $1,239,372 | $5,522 | $1,244,893 | $0 | 0.0% | ($4,600) | -0.4% |
| | **Public Street Lighting** | | | | | | | | | | | | | |
| 24 | Security Area Lighting | 7 | 8,046 | 12,441 | $2,999 | $12 | $3,011 | $2,999 | $6.30 | $3,005 | $0 | 0.0% | ($6) | -0.2% |
| 25 | Street Lighting - Company Owned | 11 | 809 | 16,496 | $4,979 | $20 | $4,999 | $4,979 | $10.46 | $4,990 | $0 | 0.0% | ($9) | -0.2% |
| 26 | Street Lighting - Customer Owned | 12 | 839 | 56,517 | $4,145 | $17 | $4,161 | $4,145 | $8.70 | $4,154 | $0 | 0.0% | ($8) | -0.2% |
| 27 | Metered Outdoor Lighting | 15 | 2,466 | 6,178 | $1,235 | $10 | $1,245 | $1,235 | $5.25 | $1,240 | $0 | 0.0% | ($5) | -0.4% |
| 28 | Traffic Signal Systems | 15 | 515 | 17,536 | $682 | $4 | $686 | $682 | $2.03 | $684 | $0 | 0.0% | ($2) | -0.3% |
| 29 | *Subtotal Public Street Lighting* | | 12,675 | 109,168 | $14,040 | $62 | $14,102 | $14,040 | $33 | $14,073 | $0 | 0.0% | ($30) | -0.2% |
| 30 | Security Area Lighting-Contracts (PTL) | -- | 5 | 8 | $1 | $0 | $1 | $1 | $0 | $1 | $0 | 0.0% | $0 | 0.0% |
| 31 | AGA/Revenue Credit | -- | | | $5 | | $5 | $5 | | $5 | | 0.0% | $0 | 0.0% |
| 32 | **Total Public Street Lighting** | | 12,680 | 109,176 | $14,045 | $62 | $14,108 | $14,045 | $33 | $14,078 | $0 | 0.0% | ($30) | -0.2% |
| 33 | **Total Sales to Ultimate Customers** | | 854,859 | 23,244,285 | $1,938,306 | $14,224 | $1,952,531 | $1,938,306 | $7,701 | $1,946,007 | $0 | 0.0% | ($6,523) | -0.3% |

**Rate Spread**
**Rocky Mountain Power**
**Estimated Effect of Proposed Changes**
**on Revenues from Electric Sales to Ultimate Consumers in Utah**
**Base Period 12 Months Ending June 2013**
**Forecast Test Period 12 Months Ending June 2015**

| Line No. | Description | Sch No. | Present Revenues ($000) | GRC NPC Allocator 2014[1] ($000) | EBA Deferral 2017[2] ($000) | EBA Deferral 2017[2] % |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| | **Residential** | | | | | |
| 1 | Residential | 1,3 | $684,505 | | ($1,900) | -0.3% |
| 2 | Residential-Optional TOD | 2 | $351 | | ($1) | -0.3% |
| 3 | AGA/Revenue Credit | -- | $33 | | | |
| 4 | **Total Residential** | | $684,889 | $170,321 | ($1,900) | -0.3% |
| | **Commercial & Industrial & OSPA** | | | | | |
| 5 | General Service-Distribution | 6 | $494,681 | | ($1,679) | -0.3% |
| 6 | General Service-Distribution-Energy TOD | 6A | $34,227 | | ($116) | -0.3% |
| 7 | General Service-Distribution-Demand TOD | 6B | $346 | | ($1) | -0.3% |
| 8 | *Subtotal Schedule 6* | | $529,255 | $161,024 | ($1,797) | -0.3% |
| 9 | General Service-Distribution > 1,000 kW | 8 | $167,313 | $56,651 | ($632) | -0.4% |
| 10 | General Service-High Voltage | 9 | $284,876 | | ($1,381) | -0.5% |
| 11 | General Service-High Voltage-Energy TOD | 9A | $3,293 | | ($16) | -0.5% |
| 12 | *Subtotal Schedule 9* | | $288,169 | $125,184 | ($1,397) | -0.5% |
| 13 | Irrigation | 10 | $13,210 | | ($50) | -0.4% |
| 14 | Irrigation-Time of Day | 10TOD | $1,286 | | ($5) | -0.4% |
| 15 | *Subtotal Irrigation* | | $14,496 | $4,897 | ($55) | -0.4% |
| 16 | Electric Furnace | 21 | $476 | | ($2) | -0.5% |
| 17 | General Service-Distribution-Small | 23 | $139,103 | $37,646 | ($420) | -0.3% |
| 18 | Back-up, Maintenance, & Supplementary | 31 | $4,576 | | ($22) | -0.5% |
| 19 | Contract 1 | -- | $27,959 | $13,217 | ($94) | -0.3% |
| 20 | Contract 2 | -- | $35,063 | $17,354 | ($194) | -0.6% |
| 21 | Contract 3 | -- | $30,035 | | $0 | 0.0% |
| 22 | AGA/Revenue Credit | -- | $2,928 | | | |
| 23 | **Total Commercial & Industrial & OSPA** | | $1,239,372 | $415,974 | ($4,613) | -0.4% |
| | **Public Street Lighting** | | | | | |
| 24 | Security Area Lighting | 7 | $2,999 | $508 | ($6) | -0.2% |
| 25 | Street Lighting - Company Owned | 11 | $4,979 | $844 | ($9) | -0.2% |
| 26 | Street Lighting - Customer Owned | 12 | $4,145 | $702 | ($8) | -0.2% |
| 27 | Metered Outdoor Lighting | 15 | $1,235 | $425 | ($5) | -0.4% |
| 28 | Traffic Signal Systems | 15 | $682 | $159 | ($2) | -0.3% |
| 29 | *Subtotal Public Street Lighting* | | $14,040 | $2,638 | ($29) | -0.2% |
| 30 | Security Area Lighting-Contracts (PTL) | -- | $1 | $0 | | |
| 31 | AGA/Revenue Credit | -- | $5 | $0 | | |
| 32 | **Total Public Street Lighting** | | $14,045 | $2,638 | ($29) | -0.2% |
| 33 | **Total Sales to Ultimate Customers** | | $1,938,306 | $588,932 | ($6,543) | -0.3% |

Note:
[1] Net Power Cost allocator from 2014 GRC, Docket No. 13-035-184.
[2] Including 2017 EBA deferral only.

| | | |
|---|---|---|
| 2017 EBA Deferral | ($6,543) | |
| Balance of 2016 EBA | $0 | |
| Target EBA Rev | ($6,543) | |
| Avg % | -0.3% | |
| Adj | 99.62% | 0.0 |

Rocky Mountain Power
Exhibit RMP___(RMM-2)
Docket No. 17-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Robert M. Meredith
Summary of Present and Proposed Prices & Billing Determinants

March 2017

**Rate Design**
**Rocky Mountain Power - State of Utah**
**Blocking Based on Adjusted Actuals and Forecasted Loads**
**Base Period 12 Months Ending June 2013**
**Forecast Test Period 12 Months Ending June 2015**

| | | Step 2 - 9/1/2015 | | Present EBA | | Proposed EBA | |
|---|---|---|---|---|---|---|---|
| | Forecasted Units | Present Price | Revenue Dollars | Price | Revenue Dollars | Price | Revenue Dollars |
| **Schedule No. 1- Residential Service** | | | | | | | |
| Total Customer | 8,511,800 | | | | | | |
| Customer Charge - 1 Phase | 8,398,777 | $6.00 | $50,392,662 | | | | |
| Customer Charge - 3 Phase | 14,094 | $12.00 | $169,128 | | | | |
| Net Metering Facilities Charge | 23,932 | | | | | | |
| First 400 kWh (May-Sept) | 1,274,636,742 | 8.8498 ¢ | $112,802,802 | 0.64% | $721,938 | -0.30% | ($338,408) |
| Next 600 kWh (May-Sept) | 1,040,456,011 | 11.5429 ¢ | $120,098,797 | 0.64% | $768,632 | -0.30% | ($360,296) |
| All add'l kWh (May-Sept) | 358,873,906 | 14.4508 ¢ | $51,860,150 | 0.64% | $331,905 | -0.30% | ($155,580) |
| All kWh (Oct-Apr) | | | | | | | |
| *First 400 kWh (Oct-Apr)* | 1,613,094,234 | 8.8498 ¢ | *$142,755,614* | 0.64% | *$913,636* | -0.30% | *($428,267)* |
| *All add'l kWh (Oct-Apr)* | 1,704,644,903 | 10.7072 ¢ | *$182,519,739* | 0.64% | *$1,168,126* | -0.30% | *($547,559)* |
| Minimum 1 Phase | 98,763 | $8.00 | $790,104 | | | | |
| Minimum 3 Phase | 166 | $16.00 | $2,656 | | | | |
| Minimum Seasonal | 0 | $96.00 | $0 | | | | |
| kWh in Minimum | 501,472 | | | | | | |
| kWh in Minimum - Summer | 223,485 | | | | | | |
| kWh in Minimum - Winter | 277,987 | | | | | | |
| Unbilled | 0 | | $0 | | | | |
| Total | 5,992,207,269 | | $661,391,652 | | $3,904,237 | | ($1,830,111) |
| **Schedule No. 3- Residential Service - Low Income Lifeline Program** | | | | | | | |
| Total Customer | 370,465 | | | | | | |
| Customer Charge - 1 Phase | 369,457 | $6.00 | $2,216,742 | | | | |
| Customer Charge - 3 Phase | 257 | $12.00 | $3,084 | | | | |
| Net Metering Facilities Charge | 0 | | | | | | |
| First 400 kWh (May-Sept) | 47,435,117 | 8.8498 ¢ | $4,197,913 | 0.64% | $26,867 | -0.30% | ($12,594) |
| Next 600 kWh (May-Sept) | 31,907,309 | 11.5429 ¢ | $3,683,029 | 0.64% | $23,571 | -0.30% | ($11,049) |
| All add'l kWh (May-Sept) | 10,205,740 | 14.4508 ¢ | $1,474,811 | 0.64% | $9,439 | -0.30% | ($4,424) |
| All kWh (Oct-Apr) | | | | | | | |
| *First 400 kWh (Oct-Apr)* | 64,598,419 | 8.8498 ¢ | *$5,716,831* | 0.64% | *$36,588* | -0.30% | *($17,150)* |
| *All add'l kWh (Oct-Apr)* | 54,308,077 | 10.7072 ¢ | *$5,814,874* | 0.64% | *$37,215* | -0.30% | *($17,445)* |
| Minimum 1 Phase | 751 | $8.00 | $6,008 | | | | |
| Minimum 3 Phase | 0 | $16.00 | $0 | | | | |
| Minimum Seasonal | 0 | $96.00 | $0 | | | | |
| kWh in Minimum | 4,249 | | | | | | |
| kWh in Minimum - Summer | 2,043 | | | | | | |
| kWh in Minimum - Winter | 2,206 | | | | | | |
| Unbilled | 0 | | $0 | | | | |
| Total | 208,458,911 | | $23,113,292 | | $133,680 | | ($62,662) |
| **Schedule No. 2 - Residential Service - Optional Time-of-Day** | | | | | | | |
| Total Customer | 5,364 | | | | | | |
| Customer Charge - 1 Phase | 5,243 | $6.00 | $31,458 | | | | |
| Customer Charge - 3 Phase | 0 | $12.00 | $0 | | | | |
| Net Metering Facilities Charge | 1,185 | | | | | | |
| On-Peak kWh (May - Sept) | 280,149 | 4.3560 ¢ | $12,203 | | | | |
| Off-Peak kWh (May - Sept) | 954,590 | (1.6334) ¢ | ($15,592) | | | | |
| First 400 kWh (May-Sept) | 675,062 | 8.8498 ¢ | $59,742 | 0.64% | $382 | -0.30% | ($179) |
| Next 600 kWh (May-Sept) | 474,415 | 11.5429 ¢ | $54,761 | 0.64% | $350 | -0.30% | ($164) |
| All add'l kWh (May-Sept) | 185,128 | 14.4508 ¢ | $26,752 | 0.64% | $171 | -0.30% | ($80) |
| All kWh (Oct-Apr) | | | | | | | |
| *First 400 kWh (Oct-Apr)* | 912,816 | 8.8498 ¢ | *$80,782* | 0.64% | *$517* | -0.30% | *($242)* |
| *All add'l kWh (Oct-Apr)* | 937,823 | 10.7072 ¢ | *$100,415* | 0.64% | *$643* | -0.30% | *($301)* |
| Minimum 1 Phase | 121 | $8.00 | $968 | | | | |
| Minimum 3 Phase | 0 | $16.00 | $0 | | | | |
| Minimum Seasonal | 0 | $96.00 | $0 | | | | |
| kWh in Minimum | 428 | | | | | | |
| kWh in Minimum - Summer | 118 | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| kWh in Minimum - Winter | | 310 | | | | | | |
| Unbilled | | 0 | | $0 | | | | |
| Total | | 3,185,671 | | $351,489 | | $2,064 | | ($967) |
| | | | | | | | | |
| **Schedule No. 6 - Composite** | | | | | | | | |
| Customer Charge | | 156,864 | $54.00 | $8,470,675 | | | | |
| All kW (May - Sept) | | 7,568,683 | | | | | | |
| All kW (Oct - Apr) | | 9,009,450 | | | | | | |
| Voltage Discount | | 679,134 | ($0.96) | ($651,969) | | | | |
| *Facilities kW* | | *16,578,133* | *$4.04* | $66,975,657 | | | | |
| *All kW (May - Sept)* | | *7,568,683* | *$14.62* | $110,654,145 | 0.85% | $940,560 | -0.40% | ($442,617) |
| *All kW (Oct - Apr)* | | *9,009,450* | *$10.91* | $98,293,100 | 0.85% | $835,491 | -0.40% | ($393,172) |
| All kWh | | 5,783,806,261 | | | | | | |
| kWh (May - Sept) | | 2,573,577,152 | 3.8127 ¢ | $98,122,776 | 0.85% | $834,044 | -0.40% | ($392,491) |
| kWh (Oct - Apr) | | 3,210,229,109 | 3.5143 ¢ | $112,817,082 | 0.85% | $958,945 | -0.40% | ($451,268) |
| Seasonal Service | | 0 | $648.00 | $0 | | | | |
| Unbilled | | 0 | | $0 | | | | |
| Total | | 5,783,806,261 | | $494,681,466 | | $3,569,040 | | ($1,679,548) |
| | | | | | | | | |
| **Schedule No. 6B - Demand Time-of-Day Option - Composite** | | | | | | | | |
| Customer Charge | | 438 | $54.00 | $23,652 | | | | |
| All On-peak kW (May - Sept) | | 6,224 | | | | | | |
| All On-peak kW (Oct - Apr) | | 4,264 | | | | | | |
| Voltage Discount | | 0 | ($0.96) | $0 | | | | |
| *Facilities kW* | | *10,488* | *$4.04* | $42,372 | | | | |
| *All On-peak kW (May - Sept)* | | *6,224* | *$14.62* | $90,995 | 0.85% | $773 | -0.40% | ($364) |
| *All On-peak kW (Oct - Apr)* | | *4,264* | *$10.91* | $46,520 | 0.85% | $395 | -0.40% | ($186) |
| All kWh | | 3,907,497 | | | | | | |
| kWh (May-Sept) | | 1,628,124 | 3.8127 ¢ | $62,075 | 0.85% | $528 | -0.40% | ($248) |
| kWh (Oct-Apr) | | 2,279,373 | 3.5143 ¢ | $80,104 | 0.85% | $681 | -0.40% | ($320) |
| Seasonal Service | | 0 | $648.00 | $0 | | | | |
| Unbilled | | 0 | | $0 | | | | |
| Total | | 3,907,497 | | $345,718 | | $2,377 | | ($1,119) |
| | | | | | | | | |
| **Schedule No. 6A - Energy Time-of-Day Option - Composite** | | | | | | | | |
| Customer Charge | | 27,307 | $54.00 | $1,474,578 | | | | |
| Facilities kW (May - Sept) | | 918,610 | $6.52 | $5,989,337 | | | | |
| Facilities kW (Oct - Apr) | | 1,059,783 | $5.47 | $5,797,013 | | | | |
| Voltage Discount | | 39,296 | ($0.61) | ($23,971) | | | | |
| On-Peak kWh (May - Sept) | | 62,251,233 | 11.9266 ¢ | $7,424,456 | 1.18% | $87,609 | -0.55% | ($40,835) |
| Off-Peak kWh (May - Sept) | | 59,556,790 | 3.5908 ¢ | $2,138,565 | 1.18% | $25,235 | -0.55% | ($11,762) |
| On-Peak kWh (Oct - Apr) | | 90,625,426 | 9.9693 ¢ | $9,034,721 | 1.18% | $106,610 | -0.55% | ($49,691) |
| Off-Peak kWh (Oct - Apr) | | 79,597,650 | 3.0060 ¢ | $2,392,705 | 1.18% | $28,234 | -0.55% | ($13,160) |
| Unbilled | | 0 | | $0 | | | | |
| Total | | 292,031,100 | | $34,227,404 | | $247,687 | | ($115,447) |
| | | | | | | | | |
| **Schedule No. 7 - Security Area Lighting - Composite** | | | | | | | | |
| *MERCURY VAPOR LAMPS* | | | | | | | | |
| 4,000 Lumen Energy Only | 29 | 24 | $5.68 | $136 | 0.40% | $1 | -0.19% | ($0) |
| 7,000 Lumen | 1 | 45,001 | $16.38 | $737,116 | 0.40% | $2,948 | -0.19% | ($1,401) |
| 7,000 Lumen Energy Only | 28 | 0 | $8.05 | $0 | 0.40% | $0 | -0.19% | $0 |
| 20,000 Lumen | 2 | 10,830 | $26.78 | $290,027 | 0.40% | $1,160 | -0.19% | ($551) |
| *SODIUM VAPOR LAMPS* | | | | | | | | |
| 5,600 Lumen New Pole | 3 | 3,563 | $14.60 | $52,020 | 0.40% | $208 | -0.19% | ($99) |
| 5,600 Lumen No New Pole | 4 | 1,746 | $12.23 | $21,354 | 0.40% | $85 | -0.19% | ($41) |
| 9,500 Lumen New Pole | 5 | 23,403 | $15.47 | $362,044 | 0.40% | $1,448 | -0.19% | ($688) |
| 9,500 Lumen No New Pole | 6 | 23,123 | $13.31 | $307,767 | 0.40% | $1,231 | -0.19% | ($585) |
| 16,000 Lumen New Pole | 7 | 2,646 | $19.46 | $51,491 | 0.40% | $206 | -0.19% | ($98) |
| 16,000 Lumen No New Pole | 8 | 2,564 | $17.13 | $43,921 | 0.40% | $176 | -0.19% | ($83) |
| 22,000 Lumen | 9 | 114 | $21.07 | $2,402 | 0.40% | $10 | -0.19% | ($5) |
| 27,500 Lumen New Pole | 10 | 3,134 | $23.51 | $73,680 | 0.40% | $295 | -0.19% | ($140) |
| 27,500 Lumen No New Pole | 11 | 4,178 | $21.23 | $88,699 | 0.40% | $355 | -0.19% | ($169) |
| 50,000 Lumen New Pole | 12 | 1,248 | $28.30 | $35,318 | 0.40% | $141 | -0.19% | ($67) |
| 50,000 Lumen No New Pole | 13 | 2,456 | $25.99 | $63,831 | 0.40% | $255 | -0.19% | ($121) |
| *SODIUM VAPOR FLOOD LAMPS* | | | | | | | | |
| 16,000 Lumen New Pole | 14 | 4,670 | $19.46 | $90,878 | 0.40% | $364 | -0.19% | ($173) |
| 16,000 Lumen No New Pole | 15 | 4,976 | $17.13 | $85,239 | 0.40% | $341 | -0.19% | ($162) |
| 27,500 Lumen New Pole | 16 | 1,102 | $23.51 | $25,908 | 0.40% | $104 | -0.19% | ($49) |
| 27,500 Lumen No New Pole | 17 | 1,570 | $21.23 | $33,331 | 0.40% | $133 | -0.19% | ($63) |
| 50,000 Lumen New Pole | 18 | 9,734 | $28.30 | $275,472 | 0.40% | $1,102 | -0.19% | ($523) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 50,000 Lumen No New Pole | 19 | 11,772 | $25.99 | $305,954 | 0.40% | $1,224 | -0.19% | ($581) |
| *METAL HALIDE LAMPS* | | | | | | | | |
| 12,000 Lumen New Pole | 20 | 0 | $29.40 | $0 | 0.40% | $0 | -0.19% | $0 |
| 12,000 Lumen No New Pole | 21 | 265 | $21.79 | $5,774 | 0.40% | $23 | -0.19% | ($11) |
| 19,500 Lumen New Pole | 22 | 110 | $34.34 | $3,777 | 0.40% | $15 | -0.19% | ($7) |
| 19,500 Lumen No New Pole | 23 | 97 | $27.43 | $2,661 | 0.40% | $11 | -0.19% | ($5) |
| 32,000 Lumen New Pole | 24 | 469 | $36.69 | $17,208 | 0.40% | $69 | -0.19% | ($33) |
| 32,000 Lumen No New Pole | 25 | 630 | $29.72 | $18,724 | 0.40% | $75 | -0.19% | ($36) |
| 107,000 Lumen New Pole | 26 | 24 | $57.58 | $1,382 | 0.40% | $6 | -0.19% | ($3) |
| 107,000 Lumen No New Pole | 27 | 60 | $49.10 | $2,946 | 0.40% | $12 | -0.19% | ($6) |
| Subtotal | | 159,509 | | $2,999,060 | | $11,996 | | ($5,698) |
| kWh Included | | 12,440,931 | | | | | | |
| Unbilled | | 0 | | $0 | | | | |
| Customers | | 8,046 | | | | | | |
| Total (kWh) | | 12,440,931 | | $2,999,060 | | $11,996 | | ($5,698) |
| | | | | | | | | |
| **Schedule No. 8 - Composite** | | | | | | | | |
| Customer Charge | | 3,282 | $70.00 | $229,740 | | | | |
| Facilities kW | | 5,010,201 | $4.76 | $23,848,557 | | | | |
| On-Peak kW (May - Sept) | | 2,097,818 | $15.56 | $32,642,048 | 0.92% | $300,307 | -0.43% | ($140,361) |
| On-Peak kW (Oct - Apr) | | 2,761,958 | $11.19 | $30,906,310 | 0.92% | $284,338 | -0.43% | ($132,897) |
| Voltage Discount | | 2,132,830 | ($1.13) | ($2,410,098) | | | | |
| On-Peak kWh (May - Sept) | | 260,094,535 | 5.0474 ¢ | $13,128,012 | 0.92% | $120,778 | -0.43% | ($56,450) |
| On-Peak kWh (Oct - Apr) | | 625,992,212 | 3.9511 ¢ | $24,733,578 | 0.92% | $227,549 | -0.43% | ($106,354) |
| Off-Peak kWh | | 1,300,960,579 | 3.4002 ¢ | $44,235,262 | 0.92% | $406,964 | -0.43% | ($190,212) |
| Unbilled | | 0 | | $0 | | | | |
| Total | | 2,187,047,326 | | $167,313,409 | | $1,339,936 | | ($626,274) |
| | | | | | | | | |
| **Schedule No. 9 - Composite** | | | | | | | | |
| Customer Charge | | 1,791 | $259.00 | $463,869 | | | | |
| Facilities kW | | 9,053,509 | $2.22 | $20,098,790 | | | | |
| On-Peak kW (May - Sept) | | 3,715,246 | $13.96 | $51,864,834 | 1.12% | $580,886 | -0.52% | ($269,697) |
| On-Peak kW (Oct - Apr) | | 5,150,021 | $9.47 | $48,770,699 | 1.12% | $546,232 | -0.52% | ($253,608) |
| On-Peak kWh (May-Sept) | | 507,349,132 | 4.6531 ¢ | $23,607,462 | 1.12% | $264,404 | -0.52% | ($122,759) |
| On-Peak kWh (Oct-Apr) | | 1,382,941,034 | 3.4989 ¢ | $48,387,724 | 1.12% | $541,943 | -0.52% | ($251,616) |
| Off-Peak kWh | | 3,137,145,375 | 2.9225 ¢ | $91,683,074 | 1.12% | $1,026,850 | -0.52% | ($476,752) |
| Unbilled | | 0 | | $0 | | | | |
| Total | | 5,027,435,541 | | $284,876,452 | | $2,960,314 | | ($1,374,432) |
| | | | | | | | | |
| **Schedule No. 9A - Energy TOD - Composite** | | | | | | | | |
| Customer Charge | | 108 | $259.00 | $27,972 | | | | |
| Facilities Charge per kW | | 235,118 | $2.22 | $521,962 | | | | |
| On-Peak kWh | | 23,805,248 | 8.6029 ¢ | $2,047,942 | 1.24% | $25,394 | -0.58% | ($11,878) |
| Off-Peak kWh | | 18,785,533 | 3.6981 ¢ | $694,708 | 1.24% | $8,614 | -0.58% | ($4,029) |
| Unbilled | | 0 | | $0 | | | | |
| Total | | 42,590,781 | | $3,292,584 | | $34,009 | | ($15,907) |
| | | | | | | | | |
| **Schedule No. 10 - Irrigation** | | | | | | | | |
| Annual Cust. Serv. Chg. - Primary | | 6 | $125.00 | $750 | | | | |
| Annual Cust. Serv. Chg. - Secondary | | 2,778 | $38.00 | $105,577 | | | | |
| Monthly Cust. Serv. Chg. | | 12,565 | $14.00 | $175,910 | | | | |
| All On-Season kW | | 323,633 | $7.33 | $2,372,230 | 0.82% | $19,452 | -0.39% | ($9,252) |
| Voltage Discount | | 10,067 | ($2.05) | ($20,637) | | | | |
| First 30,000 kWh | | 71,130,178 | 7.2971 ¢ | $5,190,440 | 0.82% | $42,562 | -0.39% | ($20,243) |
| All add'l kWh | | 51,830,436 | 5.3936 ¢ | $2,795,526 | 0.82% | $22,923 | -0.39% | ($10,903) |
| Total On Season | | 122,960,614 | | $10,619,796 | | $84,937 | | ($40,397) |
| Post Season | | | | | | | | |
| Customer Charge | | 5,886 | $14.00 | $82,404 | | | | |
| kWh | | 50,172,778 | 4.9983 ¢ | $2,507,786 | 0.82% | $20,564 | -0.39% | ($9,780) |
| Total Post Season | | 50,172,778 | | $2,590,190 | | $20,564 | | ($9,780) |
| Unbilled | | 0 | | $0 | | | | |
| TOTAL RATE 10 | | 173,133,392 | | $13,209,986 | | $105,501 | | ($50,177) |
| | | | | | | | | |
| **Schedule No. 10-TOD** | | | | | | | | |
| Annual Cust. Serv. Chg. - Primary | | 5 | $125.00 | $625 | | | | |
| Annual Cust. Serv. Chg. - Secondary | | 256 | $38.00 | $9,728 | | | | |
| Monthly Cust. Serv. Chg. | | 1,143 | $14.00 | $16,002 | | | | |
| All On-Season kW | | 37,541 | $7.33 | $275,176 | 0.82% | $2,256 | -0.39% | ($1,073) |
| Voltage Discount kW | | 1,037 | ($2.05) | ($2,126) | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| On-Peak kWh | 2,262,299 | 14.4164 ¢ | $326,142 | 0.82% | $2,674 | -0.39% | ($1,272) |
| Off-Peak kWh | 8,574,215 | 4.1542 ¢ | $356,190 | 0.82% | $2,921 | -0.39% | ($1,389) |
| Total On Season | 10,836,514 | | $981,737 | | $7,852 | | ($3,734) |
| Post Season | | | | | | | |
| Customer Charge | 570 | $14.00 | $7,980 | | | | |
| kWh | 5,920,094 | 4.9983 ¢ | $295,904 | 0.82% | $2,426 | -0.39% | ($1,154) |
| Total Post Season | 5,920,094 | | $303,884 | | $2,426 | | ($1,154) |
| Unbilled | 0 | | $0 | | | | |
| TOTAL RATE 10-TOD | 16,756,608 | | $1,285,621 | | $10,278 | | ($4,888) |
| **Schedule No. 11 - Street Lighting - Company-Owned System** | | | | | | | |
| *Sodium Vapor Lamps (HPS)* | | | | | | | |
| 5,600 Lumen - Functional | 34,757 | $11.80 | $410,133 | 0.40% | $1,641 | -0.19% | ($779) |
| 9,500 Lumen - Functional | 218,738 | $12.78 | $2,795,472 | 0.40% | $11,182 | -0.19% | ($5,311) |
| 9,500 Lumen - Functional @ 90% | 132 | $11.50 | $1,518 | 0.40% | $6 | -0.19% | ($3) |
| 9,500 Lumen - S1 | 409 | $46.54 | $19,035 | 0.40% | $76 | -0.19% | ($36) |
| 9,500 Lumen - S2 | 60 | $38.05 | $2,283 | 0.40% | $9 | -0.19% | ($4) |
| 16,000 Lumen - Functional | 21,158 | $16.94 | $358,417 | 0.40% | $1,434 | -0.19% | ($681) |
| 16,000 Lumen - Functional @ 90% | 96 | $15.25 | $1,464 | 0.40% | $6 | -0.19% | ($3) |
| 16,000 Lumen - S1 | 2,421 | $47.83 | $115,796 | 0.40% | $463 | -0.19% | ($220) |
| 16,000 Lumen - S2 | 886 | $39.34 | $34,855 | 0.40% | $139 | -0.19% | ($66) |
| 27,500 Lumen - Functional | 26,178 | $21.14 | $553,403 | 0.40% | $2,214 | -0.19% | ($1,051) |
| 27,500 Lumen - Functional @ 90% | 12 | $19.03 | $228 | 0.40% | $1 | -0.19% | ($0) |
| 27,500 Lumen - S1 | 1,253 | $51.48 | $64,504 | 0.40% | $258 | -0.19% | ($123) |
| 27,500 Lumen - S2 | 0 | $43.01 | $0 | 0.40% | $0 | -0.19% | $0 |
| 50,000 Lumen - Functional | 11,406 | $26.02 | $296,784 | 0.40% | $1,187 | -0.19% | ($564) |
| 125,000 Lumen | 0 | $51.54 | $0 | 0.40% | $0 | -0.19% | $0 |
| *Metal Halide Lamps (MH)* | | | | | | | |
| 9,000 Lumen - S1 | 36 | $48.74 | $1,755 | 0.40% | $7 | -0.19% | ($3) |
| 9,000 Lumen - S2 | 602 | $40.27 | $24,243 | 0.40% | $97 | -0.19% | ($46) |
| 12,000 Lumen - Functional | 127 | $20.13 | $2,557 | 0.40% | $10 | -0.19% | ($5) |
| 12,000 Lumen - S1 | 0 | $50.65 | $0 | 0.40% | $0 | -0.19% | $0 |
| 12,000 Lumen - S2 | 1,598 | $42.17 | $67,388 | 0.40% | $270 | -0.19% | ($128) |
| 19,500 Lumen - Functional | 386 | $22.13 | $8,542 | 0.40% | $34 | -0.19% | ($16) |
| 19,500 Lumen - S1 | 41 | $53.69 | $2,201 | 0.40% | $9 | -0.19% | ($4) |
| 19,500 Lumen - S2 | 365 | $45.20 | $16,498 | 0.40% | $66 | -0.19% | ($31) |
| 32,000 Lumen - Functional | 61 | $25.78 | $1,573 | 0.40% | $6 | -0.19% | ($3) |
| 32,000 Lumen - S1 | 0 | $55.33 | $0 | 0.40% | $0 | -0.19% | $0 |
| 32,000 Lumen - S2 | 0 | $46.86 | $0 | 0.40% | $0 | -0.19% | $0 |
| *Mercury Vapor Lamps (No New Service) (MV)* | | | | | | | |
| 4,000 Lumen | 3,279 | $11.09 | $36,364 | 0.40% | $145 | -0.19% | ($69) |
| 7,000 Lumen | 9,152 | $13.83 | $126,572 | 0.40% | $506 | -0.19% | ($240) |
| 10,000 Lumen | 186 | $19.40 | $3,608 | 0.40% | $14 | -0.19% | ($7) |
| 10,000 Lumen @ 90% | 0 | $17.46 | $0 | 0.40% | $0 | -0.19% | $0 |
| 20,000 Lumen | 996 | $24.43 | $24,332 | 0.40% | $97 | -0.19% | ($46) |
| *Incandescent Lamps (No New Service) (INC)* | | | | | | | |
| 500 Lumen | 0 | $11.99 | $0 | 0.40% | $0 | -0.19% | $0 |
| 600 Lumen | 145 | $4.24 | $615 | 0.40% | $2 | -0.19% | ($1) |
| 2,500 Lumen | 32 | $17.11 | $548 | 0.40% | $2 | -0.19% | ($1) |
| 4,000 Lumen | 162 | $20.43 | $3,310 | 0.40% | $13 | -0.19% | ($6) |
| 6,000 Lumen | 161 | $23.82 | $3,835 | 0.40% | $15 | -0.19% | ($7) |
| 10,000 Lumen | 24 | $31.47 | $755 | 0.40% | $3 | -0.19% | ($1) |
| *Fluorescent Lamps (No New Service) (FLOUR)* | | | | | | | |
| 21,000 Lumen | 12 | $27.85 | $334 | 0.40% | $1 | -0.19% | ($1) |
| *Special Service (No New Service)* | | | | | | | |
| 50,000 Lumen - Flood | 12 | $39.04 | $468 | 0.40% | $2 | -0.19% | ($1) |
| Subtotal | 334,883 | | $4,979,390 | | $19,918 | | ($9,461) |
| kWh Included | 16,496,197 | | | | | | |
| Customers | 809 | | | | | | |
| Unbilled | 0 | | $0 | | | | |
| Total | 16,496,197 | | $4,979,390 | | $19,918 | | ($9,461) |
| **Schedule No. 12 - Street Lighting - Customer-Owned System** | | | | | | | |
| **1. Energy Only, No Maintenance** | | | | | | | |
| *High Pressures Sodium Vapor Lamps* | | | | | | | |
| 5,600 Lumen | 103,438 | $1.83 | $189,292 | 0.40% | $757 | -0.19% | ($360) |
| 9,500 Lumen | 159,006 | $2.50 | $397,515 | 0.40% | $1,590 | -0.19% | ($755) |
| 16,000 Lumen | 134,332 | $3.66 | $491,655 | 0.40% | $1,967 | -0.19% | ($934) |
| 27,500 Lumen | 48,293 | $6.52 | $314,870 | 0.40% | $1,259 | -0.19% | ($598) |
| 50,000 Lumen | 65,553 | $10.02 | $656,841 | 0.40% | $2,627 | -0.19% | ($1,248) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| *Metal Halide Lamps* | | | | | | | |
| 9,000 Lumen | 6,583 | $2.55 | $16,787 | 0.40% | $67 | -0.19% | ($32) |
| 12,000 Lumen | 18,818 | $4.46 | $83,928 | 0.40% | $336 | -0.19% | ($159) |
| 19,500 Lumen | 28,281 | $6.17 | $174,494 | 0.40% | $698 | -0.19% | ($332) |
| 32,000 Lumen | 27,914 | $9.77 | $272,720 | 0.40% | $1,091 | -0.19% | ($518) |
| *Non-listed Luminaries kWh* | 10,059,553 | 6.5279 ¢ | $656,678 | 0.40% | $2,627 | -0.19% | ($1,248) |
| *Subtotal kWh* | 49,653,570 | | $3,254,780 | | $13,019 | | ($6,184) |
| *Unbilled* | | | | | | | |
| *Total* | 49,653,570 | | $3,254,780 | | $13,019 | | ($6,184) |
| *Customer* | 519 | | | | | | |
| **2a - Partial Maintenance (No New Service)** | | | | | | | |
| *Incandescent Lamps* | | | | | | | |
| 2,500 Lumen or Less | 76 | $8.96 | $681 | 0.40% | $3 | -0.19% | ($1) |
| 4,000 Lumen | 91 | $12.19 | $1,109 | 0.40% | $4 | -0.19% | ($2) |
| *Mercury Vapor Lamps* | | | | | | | |
| 4,000 Lumen | 47 | $4.64 | $218 | 0.40% | $1 | -0.19% | ($0) |
| 7,000 Lumen | 546 | $7.00 | $3,822 | 0.40% | $15 | -0.19% | ($7) |
| 20,000 Lumen | 140 | $13.33 | $1,866 | 0.40% | $7 | -0.19% | ($4) |
| 54,000 Lumen | 0 | $28.38 | $0 | 0.40% | $0 | -0.19% | $0 |
| *High Pressure Sodium Vapor Lamps* | | | | | | | |
| 5,600 Lumen | 34,609 | $4.08 | $141,205 | 0.40% | $565 | -0.19% | ($268) |
| 9,500 Lumen | 15,632 | $5.37 | $83,944 | 0.40% | $336 | -0.19% | ($159) |
| 9,500 Lumen - Decorative | 8,817 | $6.96 | $61,366 | 0.40% | $245 | -0.19% | ($117) |
| 16,000 Lumen | 2,548 | $6.52 | $16,613 | 0.40% | $66 | -0.19% | ($32) |
| 16,000 Lumen - Decorative | 799 | $8.27 | $6,608 | 0.40% | $26 | -0.19% | ($13) |
| 22,000 Lumen | 0 | $8.26 | $0 | 0.40% | $0 | -0.19% | $0 |
| 27,500 Lumen | 5,601 | $9.59 | $53,714 | 0.40% | $215 | -0.19% | ($102) |
| 27,500 Lumen - Decorative | 143 | $11.93 | $1,706 | 0.40% | $7 | -0.19% | ($3) |
| 50,000 Lumen | 10,133 | $14.00 | $141,862 | 0.40% | $567 | -0.19% | ($270) |
| 50,000 Lumen - Decorative | 157 | $15.56 | $2,443 | 0.40% | $10 | -0.19% | ($5) |
| *Metal Halide Lamps* | | | | | | | |
| 9,000 Lumen - Decorative | 702 | $9.19 | $6,451 | 0.40% | $26 | -0.19% | ($12) |
| 12,000 Lumen | 1,617 | $13.57 | $21,943 | 0.40% | $88 | -0.19% | ($42) |
| 12,000 Lumen - Decorative | 225 | $11.09 | $2,495 | 0.40% | $10 | -0.19% | ($5) |
| 19,500 Lumen | 518 | $13.71 | $7,102 | 0.40% | $28 | -0.19% | ($13) |
| 19,500 Lumen - Decorative | 6,034 | $14.13 | $85,260 | 0.40% | $341 | -0.19% | ($162) |
| 32,000 Lumen | 544 | $14.58 | $7,932 | 0.40% | $32 | -0.19% | ($15) |
| 32,000 Lumen - Decorative | 669 | $15.79 | $10,564 | 0.40% | $42 | -0.19% | ($20) |
| *Fluorescent Lamps* | | | | | | | |
| 1,000 Lumen | 0 | $3.75 | $0 | 0.40% | $0 | -0.19% | $0 |
| 21,800 Lumen | 83 | $13.92 | $1,155 | 0.40% | $5 | -0.19% | ($2) |
| *Subtotal kWh* | 5,219,065 | | $660,059 | | $2,640 | | ($1,254) |
| *Unbilled* | | | | | | | |
| *Total* | 5,219,065 | | $660,059 | | $2,640 | | ($1,254) |
| *Customer* | 221 | | | | | | |
| **2b - Full Maintenance (No New Service)** | | | | | | | |
| *Incandescent Lamps* | | | | | | | |
| 6,000 Lumen | 36 | $17.73 | $638 | 0.40% | $3 | -0.19% | ($1) |
| 10,000 Lumen | 12 | $23.40 | $281 | 0.40% | $1 | -0.19% | ($1) |
| *Mercury Vapor Lamps* | | | | | | | |
| 7,000 Lumen | 42 | $8.03 | $337 | 0.40% | $1 | -0.19% | ($1) |
| 20,000 Lumen | 0 | $15.30 | $0 | 0.40% | $0 | -0.19% | $0 |
| 54,000 Lumen | 96 | $32.48 | $3,118 | 0.40% | $12 | -0.19% | ($6) |
| *Sodium Vapor Lamps* | | | | | | | |
| 5,600 Lumen | 4,275 | $4.68 | $20,007 | 0.40% | $80 | -0.19% | ($38) |
| 9,500 Lumen | 14,686 | $6.16 | $90,466 | 0.40% | $362 | -0.19% | ($172) |
| 16,000 Lumen | 1,259 | $7.47 | $9,405 | 0.40% | $38 | -0.19% | ($18) |
| 22,000 Lumen | 0 | $9.44 | $0 | 0.40% | $0 | -0.19% | $0 |
| 27,500 Lumen | 2,408 | $10.99 | $26,464 | 0.40% | $106 | -0.19% | ($50) |
| 50,000 Lumen | 1,967 | $16.02 | $31,511 | 0.40% | $126 | -0.19% | ($60) |
| *Metal Halide Lamps* | | | | | | | |
| 12,000 Lumen | 1,188 | $15.58 | $18,509 | 0.40% | $74 | -0.19% | ($35) |
| 19,500 Lumen | 724 | $15.73 | $11,389 | 0.40% | $46 | -0.19% | ($22) |
| 32,000 Lumen | 881 | $16.72 | $14,730 | 0.40% | $59 | -0.19% | ($28) |
| 107,000 Lumen | 96 | $33.05 | $3,173 | 0.40% | $13 | -0.19% | ($6) |
| *Subtotal kWh* | 1,644,140 | | $230,028 | | $920 | | ($437) |
| *Unbilled* | | | | | | | |
| *Total* | 1,644,140 | | $230,028 | | $920 | | ($437) |
| *Customer* | 99 | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| kWh Street Lighting | 56,516,774 | | $4,144,867 | | $16,579 | | ($7,875) |
| Customers | 839 | | | | | | |
| Unbilled | | | $0 | | | | |
| Total | 56,516,774 | | $4,144,867 | | $16,579 | | ($7,875) |
| | | | | | | | |
| **Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite** | | | | | | | |
| Annual Facility Charge | 20,286 | $11.00 | $223,146 | | | | |
| Annual Customer Charge | 497 | $72.50 | $36,033 | | | | |
| Annual Minimum Charge | 0.0 | $127.50 | $0 | | | | |
| Monthly Customer Charge | 6,182 | $6.20 | $38,328 | | | | |
| All kWh | 17,536,445 | 5.3437 ¢ | $937,095 | 1.07% | $10,027 | -0.51% | ($4,779) |
| Unbilled | 0 | | $0 | | | | |
| Total | 17,536,445 | | $1,234,602 | | $10,027 | | ($4,779) |
| | | | | | | | |
| **Schedule 15.2 - Traffic Signal Systems - Composite** | | | | | | | |
| Customer Charge | 29,596 | $5.50 | $162,778 | | | | |
| All kWh | 6,177,947 | 8.4049 ¢ | $519,250 | 0.73% | $3,791 | -0.34% | ($1,765) |
| Unbilled | 0 | | $0 | | | | |
| Total | 6,177,947 | | $682,028 | | $3,791 | | ($1,765) |
| | | | | | | | |
| **Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial** | | | | | | | |
| *Primary Voltage* | | | | | | | |
| Customer Charge | 36 | $127.00 | $4,572 | | | | |
| Charge per kW (Facilities) | 10,893 | $4.30 | $46,840 | | | | |
| First 100,000 kWh | 423,833 | 6.8447 ¢ | $29,010 | 2.25% | $653 | -1.06% | ($308) |
| All add'l kWh | 0 | 5.7472 ¢ | $0 | 2.25% | $0 | -1.06% | $0 |
| Unbilled | 0 | | $0 | | | | |
| Subtotal | 423,833 | | $80,422 | | $653 | | ($308) |
| *44KV or Higher* | | | | | | | |
| Customer Charge | 24 | $127.00 | $3,048 | | | | |
| Charge per kW (Facilities) | 47,371 | $4.30 | $203,695 | | | | |
| First 100,000 kWh | 2,660,898 | 5.3851 ¢ | $143,292 | 2.25% | $3,224 | -1.06% | ($1,519) |
| All add'l kWh | 963,969 | 4.7169 ¢ | $45,469 | 2.25% | $1,023 | -1.06% | ($482) |
| Unbilled | 0 | | $0 | | | | |
| Subtotal | 3,624,867 | | $395,504 | | $4,247 | | ($2,001) |
| Total | 4,048,700 | | $475,926 | | $4,900 | | ($2,308) |
| | | | | | | | |
| **Schedule No. 23 - Composite** | | | | | | | |
| Customer Charge | 992,018 | $10.00 | $9,920,180 | | | | |
| kW over 15 (May - Sept) | 387,746 | $8.65 | $3,354,003 | 0.69% | $23,143 | -0.33% | ($11,068) |
| kW over 15 (Oct - Apr) | 347,761 | $8.70 | $3,025,521 | 0.69% | $20,876 | -0.33% | ($9,984) |
| Voltage Discount | 7,029 | ($0.48) | ($3,374) | | | | |
| First 1,500 kWh (May - Sept) | 295,977,608 | 11.7336 ¢ | $34,728,829 | 0.69% | $239,629 | -0.33% | ($114,605) |
| All Add'l kWh (May - Sept) | 309,000,008 | 6.5783 ¢ | $20,326,948 | 0.69% | $140,256 | -0.33% | ($67,079) |
| First 1,500 kWh (Oct - Apr) | 424,820,226 | 10.8000 ¢ | $45,880,584 | 0.69% | $316,576 | -0.33% | ($151,406) |
| All Add'l kWh (Oct - Apr) | 361,090,369 | 6.0567 ¢ | $21,870,160 | 0.69% | $150,904 | -0.33% | ($72,172) |
| Seasonal Service | 0 | $120.00 | $0 | | | | |
| Unbilled | 0 | | $0 | | | | |
| Total | 1,390,888,211 | | $139,102,851 | | $891,384 | | ($426,314) |
| | | | | | | | |
| **Schedule No.31 - Composite** | | | | | | | |
| *Secondary Voltage* | | | | | | | |
| Customer Charge per month | 0 | $133.00 | $0 | | | | |
| Facilities Charge, per kW month | 0 | $5.60 | $0 | | | | |
| Back-up Power Charge | | | | | | | |
| Regular, per On-Peak kW day | 0 | | | | | | |
| May - Sept | 0 | $0.88 | $0 | | | | |
| Oct - Apr | 0 | $0.62 | $0 | | | | |
| Maintenance, per On-Peak kW day | 0 | | | | | | |
| May - Sept | 0 | $0.440 | $0 | | | | |
| Oct - Apr | 0 | $0.310 | $0 | | | | |
| Excess Power, per kW month | 0 | | | | | | |
| May - Sept | 0 | $40.81 | $0 | | | | |
| Oct - Apr | 0 | $32.04 | $0 | | | | |
| *Primary Voltage* | | | | | | | |
| Customer Charge per month | 24 | $605.00 | $14,520 | | | | |
| Facilities Charge, per kW month | 38,791 | $4.46 | $173,008 | | | | |
| Back-up Power Charge | | | | | | | |
| Regular, per On-Peak kW day | 195,683 | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| May - Sept | 79,030 | $0.86 | $67,966 | | | | |
| Oct - Apr | 116,653 | $0.60 | $69,992 | | | | |
| Maintenance, per On-Peak kW day | 24,254 | | | | | | |
| May - Sept | 24,254 | $0.430 | $10,429 | | | | |
| Oct - Apr | 0 | $0.300 | $0 | | | | |
| Excess Power, per kW month | 30 | | | | | | |
| May - Sept | 0 | $38.54 | $0 | | | | |
| Oct - Apr | 30 | $29.77 | $893 | | | | |
| *Transmission Voltage* | | | | | | | |
| Customer Charge per month | 24 | $678.00 | $16,272 | | | | |
| Facilities Charge, per kW month | 153,429 | $2.63 | $403,518 | | | | |
| Back-up Power Charge | | | | | | | |
| Regular, per On-Peak kW day | 391,585 | | | | | | |
| May - Sept | 239,920 | $0.76 | $182,339 | | | | |
| Oct - Apr | 151,665 | $0.51 | $77,349 | | | | |
| Maintenance, per On-Peak kW day | 0 | | | | | | |
| May - Sept | 0 | $0.380 | $0 | | | | |
| Oct - Apr | 0 | $0.255 | $0 | | | | |
| Excess Power, per kW month | 0 | | | | | | |
| May - Sept | 0 | $32.35 | $0 | | | | |
| Oct - Apr | 0 | $23.36 | $0 | | | | |
| Subtotal | | | $1,016,286 | | $0 | | $0 |
| *Supplemental billed at Schedule 6/8/9 rate* | | | | | | | |
| **Schedule 8** | | | | | | | |
| Facilities kW | 16,065 | $4.76 | $76,469 | | | | |
| On-Peak kW (May - Sept) | 0 | $15.56 | $0 | 0.92% | $0 | -0.43% | $0 |
| On-Peak kW (Oct - Apr) | 16,065 | $11.19 | $179,767 | 0.92% | $1,654 | -0.43% | ($773) |
| Voltage Discount | 16,065 | ($1.13) | ($18,153) | | | | |
| On-Peak kWh (May - Sept) | 1,044,794 | 5.0474 ¢ | $52,735 | 0.92% | $485 | -0.43% | ($227) |
| On-Peak kWh (Oct - Apr) | 3,934,668 | 3.9511 ¢ | $155,463 | 0.92% | $1,430 | -0.43% | ($668) |
| Off-Peak kWh | 5,030,285 | 3.4002 ¢ | $171,040 | 0.92% | $1,574 | -0.43% | ($735) |
| **Schedule 9** | | | | | | | |
| Facilities kW | 103,313 | $2.22 | $229,355 | | | | |
| On-Peak kW (May - Sept) | 49,491 | $13.96 | $690,894 | 1.12% | $7,738 | -0.52% | ($3,593) |
| On-Peak kW (Oct - Apr) | 50,080 | $9.47 | $474,258 | 1.12% | $5,312 | -0.52% | ($2,466) |
| On-Peak kWh (May-Sept) | 7,647,176 | 4.6531 ¢ | $355,831 | 1.12% | $3,985 | -0.52% | ($1,850) |
| On-Peak kWh (Oct-Apr) | 10,898,121 | 3.4989 ¢ | $381,314 | 1.12% | $4,271 | -0.52% | ($1,983) |
| Off-Peak kWh | 27,727,401 | 2.9225 ¢ | $810,333 | 1.12% | $9,076 | -0.52% | ($4,214) |
| Subtotal | | | $3,559,306 | | $35,524 | | ($16,509) |
| Unbilled | 0 | | $0 | | | | |
| Total (Aggregated) | 56,282,445 | | $4,575,592 | | $35,524 | | ($16,509) |
| | | | | | | | |
| **Contract 1** | | | | | | | |
| Fixed Customer Charge | 12 | | $2,455 | | | | |
| Customer Charge | | | $1,757,447.77 | | | | |
| kW High Load Hours | 949,050 | | $9,607,156 | 0.78% | $74,936 | -0.36% | ($34,586) |
| kWh High Load Hours | 237,232,647 | | $8,613,813 | 0.78% | $67,188 | -0.36% | ($31,010) |
| kWh Low Load Hours | 298,488,523 | | $7,977,879 | 0.78% | $62,227 | -0.36% | ($28,720) |
| Total | 535,721,170 | | $27,958,751 | | $204,351 | | ($94,316) |
| | | | | | | | |
| **Contract 2** | | | | | | | |
| Customer Charge | 12 | | | | | | |
| Interruptible kWh | 795,798,676 | | $35,062,890 | 1.17% | $410,236 | -0.55% | ($192,846) |
| Total | 795,798,676 | | $35,062,890 | | $410,236 | | ($192,846) |
| | | | | | | | |
| **Contract 3** | | | | | | | |
| Customer Charge | 12 | | $8,136 | | | | |
| Facilities Charge per kW - Back-Up | 422,498 | | $921,045 | | | | |
| kW Back-Up | | | | | | | |
| Regular, per On-Peak kW day | 3,435,490 | | | | | | |
| May - Sept | 3,253,488 | | $1,673,920 | | | | |
| Oct - Apr | 182,002 | | $93,640 | | | | |
| Maintenance, per On-Peak kW day | 0 | | | | | | |
| May - Sept | | | $0 | | | | |
| Oct - Apr | | | $0 | | | | |
| Excess Power, per kW month | 0 | | | | | | |
| May - Sept | | | $0 | | | | |
| Oct - Apr | | | $0 | | | | |
| kW Supplemental | | | | | | | |
| On-Peak kW (May - Sept) | 24,807 | | $346,306 | 1.12% | $3,879 | | $0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| On-Peak kW (Oct - Apr) | 765,402 | | $7,248,357 | 1.12% | $81,182 | $0 |
| kWh Supplemental | | | | | | |
| On-Peak kWh (May-Sept) | 22,796,861 | ¢ | $1,060,761 | 1.12% | $11,881 | $0 |
| On-Peak kWh (Oct-Apr) | 204,228,863 | ¢ | $7,145,764 | 1.12% | $80,033 | $0 |
| Off-Peak kWh | 394,783,609 | ¢ | $11,537,551 | 1.12% | $129,221 | $0 |
| Total | 621,809,333 | | $30,035,480 | | $306,194 | $0 |
| **Lighting Contract - Post Top Lighting - Composite** | | | | | | |
| Energy Only Res | 60 | $2.18 | $131 | | | |
| Energy Only Non-Res | 207 | $2.1858 | $452 | | | |
| Subtotal | 267 | | $583 | | | |
| KWH Included | 7,737 | | | | | |
| Customers | 5 | | | | | |
| Unbilled | 0 | | | | | |
| Total | 7,737 | | $583 | | $0 | $0 |
| **Annual Guarantee Adjustment** | | | | | | |
| Residential | | | $33,040 | | | |
| Commercial | | | $2,726,578 | | | |
| Industrial | | | ($5,447) | | | |
| Irrigation | | | $206,563 | | | |
| Public Street & Highway Lighting | | | $4,662 | | | |
| Other Sales Public Authorities | | | $0 | | | |
| Total AGA | | | $2,965,396 | | $0 | $0 |
| TOTAL - ALL CLASSES | 23,244,284,922 | | $1,938,306,489 | | $14,224,024 | ($6,523,407) |

Rocky Mountain Power
Exhibit RMP___(RMM-3)
Docket No. 17-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Robert M. Meredith
Proposed Revisions to Schedule 94

March 2017

## ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

**DEFINITIONS: (continued)**

**Actual Energy Balancing Account Costs** (**Actual EBAC):** The actual Utah NPC and Wheeling Revenues. Adjustments shall be made to Actual EBAC that are consistent with applicable 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 additions case, or other case where Base EBAC are approved.

**Base Energy Balancing Account Costs (Base EBAC):** The Utah allocated NPC and Wheeling Revenues approved by the Commission in the most recent Utah general rate case, major plant additions case, or other case where Base EBAC are approved.

**EBA Deferral:** The monthly amount debited or credited to the EBA Deferral Account. A positive deferral reflects an under-recovery of EBAC and is debited to the EBA Deferral Account. A negative deferral reflects an over-recovery of EBAC and is credited to the EBA Deferral Account.

**EBA Deferral Account:** FERC Account No. 182.xx. The EBA Account is a balancing account. A positive (Debit) balance means that EBAC have been under collected from customers. A negative (Credit) balance means EBAC have been over collected from customers.

**EBA Deferral Account Balance:** The EBA Deferral Account Balance from the previous month plus the monthly EBA Accrual less the current monthly EBA Revenue based on the approved EBA Rate plus the monthly Carrying Charge.

**EBA Deferral Period:** The calendar year prior to the EBA Filing Date. The first EBA Deferral Period shall be the three-month period from October 1 to December 31, 2011.

**EBA Rate:** surcharge or surcredit applicable to all retail tariff rate schedules and applicable contracts as set forth in this electric service schedule to collect or refund the EBA Deferral Account Balance. The EBA rate will be a percentage applied to the monthly Power Charges and Energy Charges.

**EBA Rate Effective Date:** On or before May 1 of each year upon approval by the Commission.

**EBA Rate Effective Period:** 12-month period beginning on the EBA Rate Effective Date.

**EBA Revenue:** Revenue collected by multiplying the EBA Rate found in the Monthly Bill section of this schedule by the monthly Power Charge and Energy Charge of the Customer's applicable schedule.

(continued)

**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. Interim rates, as approved by the Commission, will go into effect May 1.
3. The Division of Public Utilities will complete its audit report and supporting testimony by November 15.
4. Intervenors may conduct discovery, with a 14 day turn around, beginning March 15.
5. Hearings on the application will be held on or around February 1.
6. Any change or true-up to interim rates necessary to recover or refund an EBA balance will take effect May 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:

**<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)

**<u>EBA FERC 501 Adjustments</u>**

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)

(continued)

**ELECTRIC SERVICE SCHEDULE NO. 94 – Continued**

**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)

**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)

(continued)

**ELECTRIC SERVICE SCHEDULE NO. 94 – Continued**

**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)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)

(continued)

## ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

**FERC 555 – Purchased Power** (continued)

FERC Sub 5556710 (continued)

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

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)

(continued)

## ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

**FERC 555 – Purchased Power** (continued)

**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)

**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).

(continued)

**ELECTRIC SERVICE SCHEDULE NO. 94 – Continued**

**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)
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.

(continued)

## ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

**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:

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

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

$NPC_{\text{Utah, month}}$ = 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.

$WR_{\text{Utah, month}}$ = 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.

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

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

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

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

(continued)

## ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

**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)

**ELECTRIC SERVICE SCHEDULE NO. 94 – Continued**

**MONTHLY BILL:** In addition to the monthly charges contained in the Customer's applicable schedule, all monthly bills shall have the following EBA Rate percentage applied to the monthly Power Charge and Energy Charge of the Customer's applicable electric service schedule. The collection of costs related to an energy balancing account from customers paying contract rates shall be governed by the terms of the contract.

| | 2016 EBA Rate | 2017 EBA Rate | Net Rate |
|---|---|---|---|
| Schedule 1 | 0.64% | -0.30% | 0.34% |
| Schedule 2 | 0.64% | -0.30% | 0.34% |
| Schedule 3 | 0.64% | -0.30% | 0.34% |
| Schedule 6 | 0.85% | -0.40% | 0.45% |
| Schedule 6A | 1.18% | -0.55% | 0.63% |
| Schedule 6B | 0.85% | -0.40% | 0.45% |
| Schedule 7* | 0.40% | -0.19% | 0.21% |
| Schedule 8 | 0.92% | -0.43% | 0.49% |
| Schedule 9 | 1.12% | -0.52% | 0.60% |
| Schedule 9A | 1.24% | -0.58% | 0.66% |
| Schedule 10 | 0.82% | -0.39% | 0.43% |
| Schedule 11* | 0.40% | -0.19% | 0.21% |
| Schedule 12* | 0.40% | -0.19% | 0.21% |
| Schedule 15 (Traffic and Other Signal Systems) | 0.73% | -0.34% | 0.39% |
| Schedule 15 (Metered Outdoor Nighttime Lighting) | 1.07% | -0.51% | 0.56% |
| Schedule 21 | 2.25% | -1.06% | 1.19% |
| Schedule 23 | 0.69% | -0.32% | 0.36% |
| Schedule 31 | ** | ** | ** |
| Schedule 32 | ** | ** | ** |

* The rate for Schedules 7, 11 and 12 shall be applied to the Charge per Lamp.
** The rate for Schedules 31 and 32 shall be the same as the applicable general service schedule.

**ELECTRIC SERVICE REGULATIONS:** Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

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

**DEFINITIONS: (continued)**

**Actual Energy Balancing Account Costs** (**Actual EBAC):** The actual Utah NPC and Wheeling Revenues. Adjustments shall be made to Actual EBAC that are consistent with applicable 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 additions case, or other case where Base EBAC are approved.

**Base Energy Balancing Account Costs (Base EBAC):** The Utah allocated NPC and Wheeling Revenues approved by the Commission in the most recent Utah general rate case, major plant additions case, or other case where Base EBAC are approved.

**EBA Deferral:** The monthly amount debited or credited to the EBA Deferral Account. A positive deferral reflects an under-recovery of EBAC and is debited to the EBA Deferral Account. A negative deferral reflects an over-recovery of EBAC and is credited to the EBA Deferral Account.

**EBA Deferral Account:** FERC Account No. 182.xx. The EBA Account is a balancing account. A positive (Debit) balance means that EBAC have been under collected from customers. A negative (Credit) balance means EBAC have been over collected from customers.

**EBA Deferral Account Balance:** The EBA Deferral Account Balance from the previous month plus the monthly EBA Accrual less the current monthly EBA Revenue based on the approved EBA Rate plus the monthly Carrying Charge.

**EBA Deferral Period:** The calendar year prior to the EBA Filing Date. The first EBA Deferral Period shall be the three-month period from October 1 to December 31, 2011.

**EBA Rate:** surcharge or surcredit applicable to all retail tariff rate schedules and applicable contracts as set forth in this electric service schedule to collect or refund the EBA Deferral Account Balance. The EBA rate will be a percentage applied to the monthly Power Charges and Energy Charges.

**EBA Rate Effective Date:** On or before ~~November~~ May 1 of each year upon approval by the Commission.

**EBA Rate Effective Period:** 12-month period beginning on the EBA Rate Effective Date.

(continued)

**EBA Revenue:** Revenue collected by multiplying the EBA Rate found in the Monthly Bill section of this schedule by the monthly Power Charge and Energy Charge of the Customer's applicable schedule.

(continued)

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## 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. Interim rates, as approved by the Commission, will go into effect May 1.
~~2.~~3. The Division of Public Utilities will complete its audit report and supporting testimony by ~~July~~ November 15.
~~3.~~4. Intervenors may conduct discovery, with a 14 day turn around, beginning March 15.
~~4.~~5. Hearings on the application will be held on or around February 1~~completed by September 15~~.
~~5.~~6. Any ~~rate~~ change or true-up to interim rates necessary to recover or refund an EBA balance will take effect ~~on or before November~~ May 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)
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)

**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

(continued)

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)

(continued)

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

**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)

**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)

(continued)

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

**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)
- 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)
- 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)

(continued)

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SAP 508054 - EIM Exp - O/U Sched Alloc: PAC to TC (Include)

(continued)

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

**FERC 555 – Purchased Power** (continued)
FERC Sub 5556710 (continued)
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
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)

(continued)

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

**FERC 555 – Purchased Power** (continued)

**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)

**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).

(continued)

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).

(continued)

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

**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)

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

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

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.

(continued)

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

**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:
$EBA\ Deferral_{\ Utah,\ month} = [(Actual\ EBAC_{\ month/MWh} – Base\ EBAC_{\ month/MWh}) \times Actual\ MWH_{\ Utah,,\ month}] \times 70\%$

Starting June 1, 2016 through December 31, 2019:
$EBA\ Deferral_{\ Utah,\ month} = [(Actual\ EBAC_{\ month/MWh} – Base\ EBAC_{\ month/MWh}) \times Actual\ MWH_{\ Utah,,\ month}] \times 100\%$

Where:

$$Actual\ EBAC_{\ month/MWh} = (NPC_{\ Utah,\ month,\ actual} / Actual\ MWh_{\ Utah,\ month}) + (WR_{\ Utah,\ month,\ actual} / Actual\ MWh_{\ Utah,\ month})$$

$$Base\ EBAC_{\ month/MWh} = (NPC_{\ Utah,\ month\ base} / Base\ MWh_{\ Utah,\ month}) + (WR_{\ Utah,\ month,\ base} / Base\ MWh_{\ Utah,\ month})$$

$NPC_{\ Utah,\ month}$ = 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.

$WR_{\ Utah,\ month}$ = 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.

**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:

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

(continued)

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

**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)

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## ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

**MONTHLY BILL:** In addition to the monthly charges contained in the Customer's applicable schedule, all monthly bills shall have the following EBA Rate percentage applied to the monthly Power Charge and Energy Charge of the Customer's applicable electric service schedule. The collection of costs related to an energy balancing account from customers paying contract rates shall be governed by the terms of the contract.

| | 2016 EBA Rate | 2017 EBA Rate | Net Rate |
|---|---|---|---|
| Schedule 1 | 0.64% | -0.30% | 0.34% |
| Schedule 2 | 0.64% | -0.30% | 0.34% |
| Schedule 3 | 0.64% | -0.30% | 0.34% |
| Schedule 6 | 0.85% | -0.40% | 0.45% |
| Schedule 6A | 1.18% | -0.55% | 0.63% |
| Schedule 6B | 0.85% | -0.40% | 0.45% |
| Schedule 7* | 0.40% | -0.19% | 0.21% |
| Schedule 8 | 0.92% | -0.43% | 0.49% |
| Schedule 9 | 1.12% | -0.52% | 0.60% |
| Schedule 9A | 1.24% | -0.58% | 0.66% |
| Schedule 10 | 0.82% | -0.39% | 0.43% |
| Schedule 11* | 0.40% | -0.19% | 0.21% |
| Schedule 12* | 0.40% | -0.19% | 0.21% |
| Schedule 15 (Traffic and Other Signal Systems) | 0.73% | -0.34% | 0.39% |
| Schedule 15 (Metered Outdoor Nighttime Lighting) | 1.07% | -0.51% | 0.56% |
| Schedule 21 | 2.25% | -1.06% | 1.19% |
| Schedule 23 | 0.69% | -0.32% | 0.36% |
| Schedule 31 | ** | ** | ** |
| Schedule 32 | ** | ** | ** |

* The rate for Schedules 7, 11 and 12 shall be applied to the Charge per Lamp.
** The rate for Schedules 31 and 32 shall be the same as the applicable general service schedule.

**ELECTRIC SERVICE REGULATIONS:** Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.