ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

March 15, 2019

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. 19-035-01**
Application to Increase the Deferred Rate through the Energy Balancing Account Mechanism

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

The enclosed proposed tariff sheets are associated with Tariff P.S.C.U No. 50 of Rocky Mountain Power, applicable to electric service in the State of Utah. Pursuant to the requirement of Rule R746-405-2D, PacifiCorp states that the proposed tariff sheets do not constitute a violation of state law or Commission rule.

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
utahdockets@pacificorp.com
jana.saba@pacificorp.com
yvonne.hogle@pacificorp.com

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

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

cc: Service List – Docket No. 19-035-01

CERTIFICATE OF SERVICE

Docket No. 19-035-01

I hereby certify that on March 15, 2019, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services	
Cheryl Murray	cmurray@utah.gov
Michele Beck	mbeck@utah.gov
Division of Public Utilities	
Erika Tedder	etedder@utah.gov
Assistant Attorney General	
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Robert Moore	rmoore@agutah.gov
Steven Snarr	stevensnarr@agutah.gov
Rocky Mountain Power	
Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com; utahdockets@pacificorp.com
Yvonne Hogle	yvonne.hogle@pacificorp.com

Jennifer Angell

Jennifer Angell
Supervisor, Regulatory Operations

R. Jeff Richards (7294)
Yvonne R. Hogle (7550)
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone No. (801) 220-4050
Facsimile No. (801) 220-3299
E-mail: yvonne.hogle@pacificorp.com

Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO INCREASE THE DEFERRED EBA RATE THROUGH THE ENERGY BALANCING ACCOUNT MECHANISM	))))	Docket No. 19-035-01

APPLICATION TO INCREASE 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 recover approximately $23.9 million in deferred EBA Costs ("EBAC"). The $23.9 million includes the following components: (1) a surcharge of approximately $22.9 million, the difference between the Actual EBAC and the Base EBAC in current base rates for the period beginning January 1, 2018 through December 31, 2018 ("Deferral Period"); (2) a credit of approximately $2.9 million for savings related to the Retiree Medical Obligation; (3) a credit of approximately $4.8 million related to an adjustment for sales made to a special contract customer; (4) approximately $0.4 million in costs related to the Utah situs resources; (5) a credit of approximately $0.2 million for adjustments related to the 2018 EBA in Docket No. 18-035-01; (6) approximately $7.6 million in costs representing the Utah-allocated

Deer Creek mine amortization expense; and (7) a charge of approximately $1.0 million in accrued interest.

The Company has included revised Tariff Schedule 94 to recover from customers $23.9 million. This results in an overall increase to retail customers of the Tariff Schedule 94 rate of approximately 1.1 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 increase 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 net power cost ("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, the Commission authorize recovery of the amounts in this Application, with a change in Utah rates to become effective, on an interim basis, May 1, 2019. 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:

Jana Saba
Utah Regulatory Affairs Manager
Rocky Mountain Power
1407 West North Temple, Suite 330
Salt Lake City, Utah 84116
E-mail: jana.saba@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 Jana Saba, Utah Regulatory Affairs Manager, at (801) 220-2823.

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 2018, several new accounts were used in the Company's accounting system to track components of NPC and wheeling revenues, including new accounts to track fuel expenses and NPC-related accounting entries arising from the Company's Utah Transition Program for Customer Generators and a new revenue account, 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 2018 through December 31, 2018, 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, 2018 through December 31, 2018.

10. The request in this Application includes seven components: (1) the EBA deferral amount ("EBA Deferral Amount") for a charge of approximately $22.9 million; (2) a credit of approximately $2.9 million for savings related to the Retiree Medical Obligation; (3) a credit of approximately $4.8 million related to an adjustment for sales made to a special contract customer; (4) approximately $0.4 million in costs related to the Utah situs resources; (5) a credit of approximately $0.2 million to reflect the order in the 2018 EBA, Docket No. 18-035-01; (6) approximately $7.6 million in costs representing the Utah-allocated Deer Creek mine amortization expense; and (7) a charge of approximately $1.0 million in accrued interest.

11. For the Deferral Period, base NPC were set at $1,491 million ("Base NPC") and wheeling revenue was set at $97 million.

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

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, 2018 through December 31, 2018 were approximately $1,584 million, compared to the $1,491 million Base NPC being used in this case.

15. Utah's allocated NPC before wheeling revenues were approximately $699 million. After crediting Utah-allocated wheeling revenues of approximately $51 million, Utah actual EBAC were approximately $648 million shown on line 3, or $26.20 per megawatt-hour ("MWh"), shown on line 5.

16. In comparison, Utah Base EBAC were approximately $587 million shown on line 8, after crediting Utah-allocated wheeling revenues of approximately $41 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 2018 load produces the deferred EBAC of approximately $23.0 million, shown on line 12.

17. The Retiree Medical Obligations savings related to the closure of the Deer Creek mine in the amount of approximately $2.9 million are shown on line 13. An adjustment for sales to a special contract customer of approximately $4.8 million, after applying a deadband, is shown on line 16. An adjustment related to the Utah situs resources, namely the Utah Subscriber Solar program and the Utah Transition Program for Customer Generators of approximately $363 thousand is shown on line 17. The credit of $0.2 million reflecting the Commission's order in Docket No. 18-035-01 is shown on line 22. The Deer Creek amortization expense of approximately $7.6 million is reflected on line 25. A charge for interest of approximately $538 thousand for the Deferral Period (January 1, 2018 through December 31, 2018) is shown on line 23 and expense for interest of approximately $472 thousand (from January 2019 through April 2019) is shown on line 26. The total ending deferral amount of approximately $23.9 million is shown on line 27.

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

Calendar Year 2018 EBA Deferral			*Exhibit RMP___(MGW-1) Reference*
Actual EBA ($/MWh)	$	26.20	*Line 5*
Base EBA ($/MWh)		25.25	*Line 10*
$/MWh Differential	**$**	**0.95**	
Utah Sales (MWh)		24,719,693	*Line 4*
EBA Deferrable*	$	22,854,942	*Line 12*
Incremental Non-Fuel FAS 106 Savings*		(2,921,597)	*Line 13*
Special Contract Customer Adjustment*		(4,845,293)	*Line 16*
Utah Situs Resource Adjustment*		362,506	*Line 17*
Total Deferrable	$	15,450,557	*Line 18*
2018 EBA Order	$	(218,375)	*Line 22*
Deer Creek Amortization Costs		7,635,599	*Line 25*
Interest Accrued through December 31, 2018		537,935	*Line 23*
Interest Jan. 1, 2019 through April 30, 2019		471,637	*Line 26*
Requested EBA Recovery	**$**	**23,877,352**	*Line 27*

** 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 2019 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 **Exhibit RMP___(RMM-1)** displays the Company's proposed rate spread, as discussed above. The proposal would result in an overall increase of approximately 1.1 percent to

customers in Utah. Mr. Meredith's **Exhibit RMP___(RMM-2)** includes billing determinants and the calculations of the proposed EBA rates in this case. **Exhibit RMP___(RMM-3)** contains the proposed rates and revisions for Tariff Schedule 94.

Customer Class	**Proposed Percentage Change 2019 EBA**
Residential	
Schedules 1, 2, 3	0.9%
General Service	
Schedule 23	0.9%
Schedule 6	1.1%
Schedule 8	1.2%
Schedule 9	1.5%
Irrigation	
Schedule 10	1.2%
Public Street and Area Lighting Schedules	
Schedules 7, 11, 12	0.6%
Schedule 15	1.2%

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission approve interim rates as provided in Tariff Schedule 94 to recover the costs identified in this Application, as filed, with an effective date of May 1, 2019.

DATED this 15th day of March 2019.

Respectfully submitted,

ROCKY MOUNTAIN POWER

Yvonne R. Hogle
____

R. Jeff Richards
Yvonne R. Hogle
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone No. (801) 220-4050
Facsimile No. (801) 220-3299
E-mail: yvonne.hogle@pacificorp.com
Attorneys for Rocky Mountain Power

Rocky Mountain Power
Docket No. 19-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Michael G. Wilding

March 2019

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 Director, Net Power Costs and Regulatory Policy.

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. During my tenure at the Company, I have worked on various regulatory projects including general rate cases, the multi-state protocol, and net power cost filings. I have been employed by the Company since 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, Oregon, Washington, and California.

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, 2018 through December 31, 2018 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $23.9 million for excess EBA-related costs, including interest, the Utah-allocated non-fuel savings related to the settlement of the Deer Creek Retiree Medical Obligation, the Utah-allocated Deer Creek amortization expense, an adjustment for sales made to a special contract customer, a Utah situs resource true-up of solar facilities included in the EBA, and an adjustment related to the 2018 EBA order in Docket No. 18-035-01;

- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC"); and,
- Discussion about the Company's participation in the energy imbalance market ("EIM") with California Independent System Operator ("CAISO") and the benefits from EIM that are passed through to customers.

Q. Are additional witnesses presenting testimony specifically for the EBA and Tariff Schedule 94 in this case?

A. Yes. Mr. Robert M. Meredith, Manager, Pricing and Cost of Service, provides testimony on the proposed Tariff Schedule 94 rates.

SUMMARY OF THE EBA DEFERRAL CALCULATION

Q. Please summarize the Company's EBA application.

A. The Company's application requests recovery of $23.9 million, comprised of $22.9 million of EBA-related costs, a credit of $2.9 million for savings for the Retiree Medical Obligation, a credit of $4.8 million for sales made to a special contract customer, $0.4 million adjustment for Utah situs resources, a credit of $0.2 million for the 2018 EBA in Docket No. 18-035-01, $7.6 million cost for the Utah-allocated Deer Creek mine amortization expense, and $1 million of interest.

Q. Are there any changes to the EBA calculation?

A. Yes. Adjustments have been included as part of the EBA calculation for the following items:

- Recovery of export credits from Electric Service Schedule 136, the Utah Transition Program for Customer Generators per Docket No. 14-035-114; and
- The 2018 EBA order in Docket No. 18-035-01.

EBA DEFERRAL CALCULATION

Q. Please describe the calculation of the EBA deferral included in this filing.

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 2018 EBA Deferral			*Exhibit RMP___(MGW-1) Reference*
Actual EBA ($/MWh)	$	26.20	*Line 5*
Base EBA ($/MWh)		25.25	*Line 10*
$/MWh Differential	**$**	**0.95**	
Utah Sales (MWh)		24,719,693	*Line 4*
EBA Deferrable*	$	22,854,942	*Line 12*
Incremental Non-Fuel FAS 106 Savings*		(2,921,597)	*Line 13*
Special Contract Customer Adjustment*		(4,845,293)	*Line 16*
Utah Situs Resource Adjustment*		362,506	*Line 17*
Total Deferrable	$	15,450,557	*Line 18*
2018 EBA Order	$	(218,375)	*Line 22*
Deer Creek Amortization Costs		7,635,599	*Line 25*
Interest Accrued through December 31, 2018		537,935	*Line 23*
Interest Jan. 1, 2019 through April 30, 2019		471,637	*Line 26*
Requested EBA Recovery	**$**	**23,877,352**	*Line 27*

** Calculated monthly*

The EBA deferral of $22.9 million is calculated as the difference between the Actual NPC and wheeling revenue and the Base NPC and wheeling revenue, as established in the 2014 general rate case ("GRC"). The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

$$EBA\ Deferral_{\ Utah,month} =$$
$$\left[\left(Actual\ EBAC_{\frac{Utah,month}{MWh}} - \ Base\ EBAC_{\ \frac{Utah,month}{MWh}}\right) \times \ Actual\ MWh_{Utah,month}\right]$$

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 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 $1,584 million. This amount captures all components of NPC as defined in the Company's GRC 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 (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 residential exchange credit pass-through if applicable
- Account 565 – Transmission of electricity by others

During 2018, 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 the Utah Transition Program for Customer Generators and a new revenue account. 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 No. 94. Exhibit RMP___(MGW-2) identifies the new accounts used in 2018. The new accounts are also included in the revised tariff sheets provided in the testimony of Mr. 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:

- out of period accounting entries booked in the Deferral Period that relate to operations prior to implementation of the EBA in October 2011;
- buy-through of economic curtailment by interruptible industrial customers;
- revenue from a contract related to the Leaning Juniper wind resource;
- situs assignment of the generation from Oregon solar resources procured to satisfy Oregon Revised Statute 757.370 solar capacity standard;
- situs assignment of Oregon allocated excess amortization related to a prepaid wheeling expense;
- situs assignment of certain Utah resources;
- coal inventory adjustments to reflect coal costs in the correct period;
- legal fees related to fines and citations included in the cost of coal;
- adjustments related to liquidated damages that occurred outside the Deferral Period (all liquidated damage fees per a coal supply agreement are booked

in accordance with generally accepted accounting principles); and,

- a write-off of disputed energy charges associated with a wholesale sale.

Additional details regarding each of these adjustments and the impact on NPC are provided in Additional Filing Requirement 15.

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. 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 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. 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 megawatt-hour ("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. For the 2019 EBA, the adjustment for sales made to a special contract customer is a $4.8 million credit.

Q. Please describe the Utah Situs Resource Adjustment.

A. The Utah Situs Resource Adjustment accounts for the Utah situs costs of certain resources, namely the Utah Subscriber Solar Program and the Utah Transition Program for Customer Generators.

Q. Please describe the Utah Subscriber Solar Program.

A. The Commission approved the "Subscriber Solar Program Rider - Optional" Tariff Schedule 73, effective March 28, 2016, which enables participating Utah customers to purchase electricity from a specific utility-scale solar resource. Customers can elect to purchase blocks of energy at a set amount each month, and the value of any excess, unused block energy is rolled forward to future months. Participating blocks of energy purchased are subject to rates specific to Schedule 73 and are not subject to EBA adjustment rate schedule changes (Schedule 73, Special Condition 15).

Q. Please describe the adjustment to the EBA for the Utah Subscriber Solar Program Resource.

A. Under the stipulation in Docket No. 15-035-61, the solar resource is included as a Utah-situs resource in net power costs.[1] The generation costs of the solar resource are compared to the generation charges paid by solar subscriber customers and the difference is either recovered from or credited back to Utah customers through the EBA. In addition, there will be no load adjustments and no change in allocation factors due to the program. The EBA adjustment for subscriber solar is approximately $0.1 million.

Q. Please describe the Utah Transition Program for Customer Generators ("Transition Program").

A. In Docket No. 14-035-114, the Commission approved the Transition Program Tariff Schedule 136, effective November 15, 2017, which measures the difference between the electricity supplied by the Company and the electricity generated by an eligible customer-generator and fed back to the electric grid at 15-minute intervals. The program enables eligible customers to offset part or all of their own electrical requirements with self-generation and receive export credits for energy fed back to the electric grid.

---

[2] Order approving amended settlement agreement, Docket No. 15-035-61, issued October 21, 2015, Page 7 of the amended settlement stipulation.

Q. Please describe the adjustment to the EBA for the Transition Program.

A. Under the stipulation in Docket No. 14-035-114, the difference between export credits to eligible customers and the market value of the exports is recovered from or credited back to Utah customers through the EBA.[2] The EBA adjustment for the Transition Program is approximately $0.2 million.

Q. Please explain the Deer Creek amortization expense.

A. The Company closed the Deer Creek Mine in 2015 before having fully recovered its investment through base rates. In the Deer Creek Settlement, it was determined that the unrecovered investment would be amortized and recovered through the EBA. The 2019 EBA is the last year of Deer Creek amortization expense. The Utah-allocated Deer Creek amortization expense for calendar year 2018 is $7.6 million and includes the remaining balance, net of salvage value proceeds and a Utah specified capital work in progress disallowance.

Q. Please describe the adjustment for the Deer Creek Retiree Medical Obligation.

A. The 2019 EBA includes the non-fuel saving related to the settlement of Deer Creek Retiree Medical Obligation. In the 2019 EBA the non-fuel savings are allocated to Utah using the system overhead ("SO") allocation factor from the June 30, 2018 results of operations. At the time of this filing, the calendar year 2018 SO allocation factor was not yet available.

Q. Please describe the adjustment related to the 2018 EBA.

A. In the order in Docket No. 18-035-01, issued March 12, 2019, the Commission ordered an adjustment related to the 2018 EBA to be carried forward and offset against the

[2] Order approving settlement stipulation, Docket No. 14-035-114, issued September 29, 2017, Page 18.

Company's request in the 2019 EBA filing. The Company calculated the adjustment to be $218,375, based on the Commission's order, which has been included in the 2019 EBA as a credit to customers.

DIFFERENCES IN NPC

Q. On a total-Company basis, what was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total-Company basis, Actual NPC for the Deferral Period were $1,584 million, more than Base NPC for the Deferral Period by approximately $93 million. Table 2 below provides a high level summary of the difference between Base NPC and Actual NPC by category on a total-Company basis.

Table 2
Net Power Cost Reconciliation ($ millions)

	TOTAL
Base NPC	**$ 1,491**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	153
Purchased Power Expense	84
Coal Fuel Expense	(95)
Natural Gas Expense	(37)
Wheeling and Other Expense	(14)
Total Increase/(Decrease)	**90**
2014 GRC Settlement Adjustment	3
Total Company NPC Difference	**$ 93**
Adjusted Actual NPC	**$ 1,584**

Q. Please describe the Base NPC the Company used to calculate the NPC component of the EBA deferral.

A. The Base NPC for the 2019 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 million.

Q. 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 higher than Base NPC due to a $153 million reduction in wholesale sales and a $84 million increase in purchased power expense. The items were partially offset by a $95 million reduction in coal fuel expense, $37 million reduction in natural gas expense, and a $14 million reduction in wheeling and other expenses.

Q. Please explain the changes in wholesale sales revenue.

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

Revenue from market transactions is approximately $108 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 $9.74/MWh, or 25 percent, lower than the average price in Base NPC. Actual wholesale market volumes were 896 gigawatt-hours ("GWh"), or 11 percent, lower than the Base NPC. In addition, expired contracts accounted for approximately $20 million of the decrease in wholesale sales revenue.

Q. Please explain the changes in purchased power expense.

A. Since the 2014 GRC that set Base NPC there have been multiple changes to the Company's long-term purchased power expense including 16 new large qualifying facility contracts and the expiration of the Hermiston purchase power agreement and the Georgia-Pacific Camas contract, which resulted in lower purchased power costs of $91.3 million.

Additionally, expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) increased by $108.5 million compared to Base NPC. Actual market purchases were 952 GWh (19 percent) higher than Base NPC and the average price of actual market purchases transactions was $13.41/MWh (44 percent) higher than Base NPC.

Q. Please explain the changes in wheeling expenses.

A. Actual long-term wheeling expense decreased by approximately $14 million when compared to Base NPC due to expired wheeling contracts. This was partially offset by an increase of $2 million of short-term wheeling expenses.

Q. Please discuss the changes in coal fuel expense.

A. The driver of the decrease in coal fuel expense is that coal generation volume decreased 6,157 GWh (14 percent) compared to Base NPC. The average cost of coal generation slightly increased from $19.77/MWh in Base NPC to $20.49/MWh in the Deferral Period, but the lower generation results in an overall decrease of approximately $95 million in coal fuel expense.

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

A. The total natural gas fuel expense in Actual NPC decreased by $37 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 $22.97/MWh (42 percent) in the Deferral Period. Reduced costs were partially offset by an increase in natural gas generation volume of 3,525 GWh (50 percent) above Base NPC during the Deferral

Period.

Q. Please provide an overview of the Enbridge natural gas pipeline rupture and its impact on Company operations and costs.

A. On October 9, 2018, the Enbridge natural gas pipeline that transports natural gas produced in the Western Canadian Sedimentary Basin to consumers in British Columbia ("B.C.") and, through interconnecting pipelines, the Northwestern United States ("U.S."), experienced a massive rupture. The pipeline was brought back into service in late October 2018, however, at a reduced capacity until testing of the many segments of the pipeline can be completed. Currently the pipeline is operating at approximately 85 percent of capacity. Original estimates expected the pipeline to be back in full service sometime late spring 2019; however, revised forecasts are now calling for full service to be established sometime in September 2019. Spot natural gas prices at the Sumas B.C.-U.S. border trading point have traded as high as $159 per million British thermal units on days of intense demand.

The pipeline rupture and reduced operating capacity has impacted electricity prices primarily at the Mid-Columbia power market hub, but increased electricity prices are also being experienced at other trading points where PacifiCorp transacts. Because of PacifiCorp's geographical and resource diversity, the impact to the Company was not as severe as other utilities and power producers that have a high reliance on Sumas natural gas supplies. PacifiCorp has one natural gas-fired generator—the Chehalis plant—that is sourced from the Sumas natural gas hub. Due to the pipeline rupture, at times there has been limited availability of natural gas flowing to the Sumas gas hub which can cause the price to run the Chehalis plant to be uneconomical or at times even unable to run due to the lack of gas availability at Sumas. As a result, overall the natural gas constraint at Sumas has contributed to higher prices at Mid-Columbia, which has put upward pressure on net power costs.

Q. What is the current status of natural gas flow at the Sumas natural gas hub?

A. As of the date of this filing, natural gas flows to the Sumas gas hub continue to be restricted as pipeline repair and testing continues. Westcoast Pipeline, which operates the Enbridge pipeline, has indicated that flows to Sumas will be restricted through the summer of 2019. These restrictions will cause increased price volatility and higher power prices this summer at Mid-Columbia.

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. The EIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. The Company is able to calculate the margin realized on its EIM imports and exports, the inter-regional benefit. The Company's EIM inter-regional benefit for the deferral period was approximately $57 million.

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

A. Using actual information from the EIM, including five- and 15-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. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(MGW-1)
Docket No. 19-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Monthly EBA Deferral

March 2019

Utah Energy Balancing Account Mechanism
January 1, 2018 - December 31, 2018
Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor

Line No.		Reference	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Actual: Utah Allocated															
1	NPC	(2.1)	$ 53,389,480	$ 51,061,152	$ 52,849,882	$ 48,228,940	$ 47,139,116	$ 59,400,189	$ 87,580,827	$ 82,355,570	$ 54,852,478	$ 52,440,269	$ 53,787,010	$ 56,057,671	$ 699,142,585
2	Wheeling Revenue	(4.1)	(3,328,161)	(3,797,258)	(4,220,678)	(3,375,412)	(6,992,252)	(4,041,370)	(5,582,435)	(5,259,870)	(4,195,242)	(3,716,067)	(3,526,930)	(3,407,291)	(51,442,964)
3	Total	∑ Lines 1:2	$ 50,061,320	$ 47,263,895	$ 48,629,205	$ 44,853,528	$ 40,146,864	$ 55,358,820	$ 81,998,392	$ 77,095,701	$ 50,657,236	$ 48,724,201	$ 50,260,080	$ 52,650,380	$ 647,699,621
4	Jurisdictional Sales	(5.2)	2,009,809	1,780,358	1,844,716	1,789,202	1,887,493	2,213,176	2,631,064	2,458,448	2,103,926	1,958,368	1,925,250	2,117,884	24,719,693
5	Actual Utah $/MWh	Line 3 / Line 4	**$ 24.91**	**$ 26.55**	**$ 26.36**	**$ 25.07**	**$ 21.27**	**$ 25.01**	**$ 31.17**	**$ 31.36**	**$ 24.08**	**$ 24.88**	**$ 26.11**	**$ 24.86**	**$ 26.20**
Base: Utah Allocated															
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	(5.2)	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	$ 0.39	$ 1.45	$ 0.49	$ 0.60	$ (3.88)	$ (0.45)	$ 5.10	$ 4.72	$ (0.75)	$ (0.21)	$ 1.44	$ (0.00)	$ 0.95
12	EBA Deferrable	Line 4 * Line 11	**$ 791,275**	**$ 2,587,681**	**$ 911,026**	**$ 1,078,405**	**$ (7,330,994)**	**$ (988,675)**	**$ 13,419,561**	**$ 11,605,913**	**$ (1,570,824)**	**$ (415,499)**	**$ 2,777,259**	**$ (10,186)**	**$ 22,854,942**
13	Incremental Non-Fuel FAS 106 Savings	(6.1)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	(243,466)	$ (2,921,597)
14	Special Contract Customer Adjustment Subject to Deadband	(7.1)	353,068	599,826	570,986	898,616	967,244	1,248,629	(2,374,668)	(2,446,978)	(57,357)	(1,218,921)	(1,907,032)	(1,828,705)	$ (5,195,293)
15	Symmetrical Deadband	Docket 16-035-33	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
16	Total Special Contract Adjustment	Line 14 - Line 15	$ 3,068	$ 599,826	$ 570,986	$ 898,616	$ 967,244	$ 1,248,629	$ (2,374,668)	$ (1,913,700)	$ -	$ (1,109,557)	$ (1,907,032)	$ (1,828,705)	$ (4,845,293)
17	Utah Situs Resource Adjustment	(8.1)	(63,348)	(46,337)	24,965	29,032	116,131	178,480	77,401	78,409	94,468	18,522	(30,828)	(114,390)	362,506
18	Total Incremental EBA Deferral	∑ Lines 12:13 and Lines 16:17	**$ 487,529**	**$ 2,897,704**	**$ 1,263,510**	**$ 1,762,585**	**$ (6,491,086)**	**$ 194,969**	**$ 10,878,827**	**$ 9,527,156**	**$ (1,719,822)**	**$ (1,750,001)**	**$ 595,933**	**$ (2,196,747)**	**$ 15,450,557**
Energy Balancing Account:															
19	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%	
20	Beginning Balance	Prior Month Line 24	$ -	$ 488,748	$ 3,396,140	$ 4,679,789	$ 6,470,180	$ (224,250)	$ (29,915)	$ 10,875,960	$ 20,481,313	$ 18,859,598	$ 17,199,520	$ 17,882,940	$ -
21	Incremental Deferral	Line 18	487,529	2,897,704	1,263,510	1,762,585	(6,491,086)	194,969	10,878,827	9,527,156	(1,719,822)	(1,750,001)	595,933	(2,196,747)	15,450,557
22	2018 EBA Order	Docket 18-035-01	-	-	-	-	(218,375)	-	-	-	-	-	-	-	(218,375)
23	Interest	Line 19 * (Line 20 + 50% x Line 21)	1,219	9,688	20,139	27,805	15,031	(634)	27,047	78,198	98,107	89,923	87,487	83,923	537,935
24	**Ending Balance**	∑ Lines 20:23	**$ 488,748**	**$ 3,396,140**	**$ 4,679,789**	**$ 6,470,180**	**$ (224,250)**	**$ (29,915)**	**$ 10,875,960**	**$ 20,481,313**	**$ 18,859,598**	**$ 17,199,520**	**$ 17,882,940**	**$ 15,770,116**	**$ 15,770,116**
25	Deer Creek Mine Amortization	(6.1)													$ 7,635,599
26	Accrued Interest through April 30, 2019	∑ Lines 24:25 * (1 + 1.06% / 12) ^ 4 - ∑ Lines 24:25													471,637
27	**Requested EBA Recovery**	∑ Lines 24:26													**$ 23,877,352**

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. 19-035-01
Witness: Michael G. Wilding

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Michael G. Wilding

List of New SAP Accounts

March 2019

FERC and SAP Accounts Included in EBA
Asterisks denote accounts used in 2018 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	
	5552700	505185	Net Metering Export Credit-UT Solar	*
	5552500	505190	OR Solar Incentive Purchases	
	5552700	505195	Purchased Power-UT Subscriber Solar	
	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	

FERC and SAP Accounts Included in EBA
Asterisks denote accounts used in 2018 that should be added to the Schedule 94 tariff sheet

Category	FERC Account	SAP Account	Description	
	5556710	508052	EIM Exp - O/U Sched Alloc: w/CAISO	
	5556710	508161	EIM Exp-7070 Flex Ramp F/C: PAC to TC	
	5556710	508162	EIM Exp-7076 FR Allc	
	5556710	508165	EIM Exp 7077 Daily Up: PAC to TC	
	5556710	508166	EIM Exp-7078 Mo U PT	
	5556710	508167	EIM Exp-7087 Daily Down: PAC to TC	
	5556710	508168	EIM Exp-7088 Mo Dwn	
	5558000	505227	Purch Power Exp Offset - Under Cap Lease	
FERC Account 565 - Wheeling 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	361500	Natural Gas Sales Revenue - Regulated	
	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	301952	Ancillary Rev Sch 6-Supp (Transm)	
	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	302832	I/C Other Wheeling Revenue-Nevada	*
	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	
	4561990	305950	Ancil Revenue Sch 5 - Subject to Refund	
	4561990	305960	Ancil Revenue Sch 6 - 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
Docket No. 19-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Robert M. Meredith

March 2019

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 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 14 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over eight 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, Wyoming, Idaho, Oregon, 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, 2018 ("2019 EBA").

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

A. The change in Schedule 94 is an increase of $20.5 million, or 1.1 percent. This net change is the difference between the current collection level of $2.8 million and the new proposed collection level of $23.2 million for the 2019 EBA. Exhibit RMP___(RMM-1), page 1, shows the net impact by rate schedule.

PROPOSED EBA RATE SPREAD

Q. What is the 2019 EBA deferral amount in this case?

A. The total 2019 EBA deferral is $23.9 million, as shown in Table 1 of Mr. Wilding's testimony. Additionally, the Company currently estimates a net over-collection of $0.6 million by April 30, 2019 for the interim 2018 EBA deferral currently being collected in Schedule 94[1], which includes a transfer of the balance from the 2017 EBA deferral.[2] The Company proposes to include this estimated over-collection in the 2019 EBA deferral, which results in a total target collection of $23.2 million in Schedule 94. The Company proposes to recover this amount over one year with interim rates effective May 1, 2019, 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 2019 EBA credits and the final amount approved by the Commission would be included in new rates, effective May 1, 2020.

[1] The interim 2018 EBA deferral amounts were authorized in Docket No. 18-035-01 for the 2018 deferral ("2018 EBA").
[2] The 2017 EBA deferral amounts were authorized in Docket No. 17-035-01 for the 2017 deferral ("2017 EBA").

Q. How does the Company propose to allocate the 2019 EBA deferral balance across customer classes?

A. The Company proposes to spread the 2019 EBA deferral across customer rate schedules consistent with the Net Power Cost (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 2019 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 2019 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. 17-035-72, the 2019 EBA revenue allocation for Contract Customer 1 is based on the overall 2019 EBA percentage to tariff customers in Utah.

Q. How does the Company propose to collect the 2019 EBA deferral after these adjustments to the NPC Allocators?

A. The results of the 2019 EBA deferral spread based on the NPC Allocator are then proportionally adjusted for all customer classes to collect a total target amount of

$23.2 million.

Q. What present revenues and billing determinants is the Company proposing to use to allocate the 2019 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. The billing determinants were adjusted to account for revenue from loads enrolled in the Subscriber Solar Program that no longer pay for the EBA.

Q. Why were billing determinants adjusted for revenues from the Subscriber Solar Program?

A. 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. Since the commercial operation date for the Subscriber Solar Program solar resource was December 30, 2016, the EBA would not apply to the revenue from energy enrolled in the Subscriber Solar Program during the entire period over which the 2019 EBA would be collected (May 1, 2019 through April 30, 2020). Adjusting the billing determinants reflects this change in revenue that is subject to EBA adjustments.

Q. Please describe how billing determinants were adjusted for revenues from the Subscriber Solar Program.

A. The revenue from blocks enrolled in the Subscriber Solar Program from the most recent 12-month period available at the time of this filing (March 1, 2018 through February 28, 2019) was subtracted from the revenue from energy charges for Residential, Schedule 6, Schedule 6A, and Schedule 23 customers which are used as billing determinants for calculating the 2019 EBA rates.

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, including the Subscriber Solar Program adjustment, 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.

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. 19-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Net Impact by Rate Schedule

March 2018

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	Sch No.	No. of Customers Forecast	MWh Forecast	Present Revenue ($000) Base	Present Revenue ($000) EBA	Present Revenue ($000) Net	Proposed Revenue ($000) Base	Proposed Revenue ($000) EBA	Proposed Revenue ($000) Net	Change Base ($000)	Change Base (%)	Change Net ($000)	Change Net (%)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Residential													
1	Residential	1,3	740,189	6,200,666	$684,505	$818	$685,323	$684,505	$6,730	$691,235	$0	0.0%	$5,913	0.9%
2	Residential-Optional TOD	2	447	3,186	$351	$0	$352	$351	$3	$355	$0	0.0%	$3	0.9%
3	AGA/Revenue Credit	--			$33		$33	$33		$33	$0	0.0%	$0	0.0%
4	**Total Residential**		740,636	6,203,852	$684,889	$818	$685,708	$684,889	$6,734	$691,623	$0	0.0%	$5,916	0.9%
	Commercial & Industrial & OSPA													
5	General Service-Distribution	6	13,072	5,783,806	$494,681	$713	$495,395	$494,681	$5,960	$500,641	$0	0.0%	$5,246	1.1%
6	General Service-Distribution-Energy TOD	6A	2,276	292,031	$34,227	$50	$34,277	$34,227	$413	$34,640	$0	0.0%	$363	1.1%
7	General Service-Distribution-Demand TOD	6B	37	3,907	$346	$0	$346	$346	$4	$350	$0	0.0%	$3	1.0%
8	*Subtotal Schedule 6*		15,385	6,079,745	$529,255	$764	$530,018	$529,255	$6,377	$535,631	$0	0.0%	$5,613	1.1%
9	General Service-Distribution > 1,000 kW	8	274	2,187,047	$167,313	$262	$167,576	$167,313	$2,258	$169,571	$0	0.0%	$1,995	1.2%
10	General Service-High Voltage	9	149	5,027,436	$284,876	$581	$285,458	$284,876	$4,916	$289,793	$0	0.0%	$4,335	1.5%
11	General Service-High Voltage-Energy TOD	9A	9	42,591	$3,293	$7	$3,299	$3,293	$57	$3,349	$0	0.0%	$50	1.5%
12	*Subtotal Schedule 9*		158	5,070,026	$288,169	$588	$288,757	$288,169	$4,973	$293,142	$0	0.0%	$4,385	1.5%
13	Irrigation	10	2,784	173,133	$13,210	$21	$13,231	$13,210	$178	$13,388	$0	0.0%	$157	1.2%
14	Irrigation-Time of Day	10TOD	261	16,757	$1,286	$2	$1,288	$1,286	$17	$1,303	$0	0.0%	$15	1.2%
15	*Subtotal Irrigation*		3,045	189,890	$14,496	$23	$14,518	$14,496	$195	$14,690	$0	0.0%	$172	1.2%
16	Electric Furnace	21	5	4,049	$476	$1	$477	$476	$8	$484	$0	0.0%	$7	1.5%
17	General Service-Distribution-Small	23	82,668	1,390,888	$139,103	$181	$139,283	$139,103	$1,496	$140,599	$0	0.0%	$1,316	0.9%
18	Back-up, Maintenance, & Supplementary	31	4	56,282	$4,576	$7	$4,583	$4,576	$59	$4,635	$0	0.0%	$52	1.1%
19	Contract 1	--	1	535,721	$27,959	$39	$27,998	$27,959	$335	$28,294	$0	0.0%	$296	1.1%
20	Contract 2	--	1	795,799	$35,063	$81	$35,144	$35,063	$687	$35,750	$0	0.0%	$607	1.7%
21	Contract 3	--	1	621,809	$30,035	$0	$30,035	$30,035	$0	$30,035	$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	$1,945	$1,241,317	$1,239,372	$16,388	$1,255,760	$0	0.0%	$14,443	1.2%
	Public Street Lighting													
24	Security Area Lighting	7	8,046	12,441	$2,999	$2	$3,001	$2,999	$20	$3,019	$0	0.0%	$18	0.6%
25	Street Lighting - Company Owned	11	809	16,496	$4,979	$4	$4,983	$4,979	$33	$5,013	$0	0.0%	$29	0.6%
26	Street Lighting - Customer Owned	12	839	56,517	$4,145	$3	$4,148	$4,145	$28	$4,173	$0	0.0%	$24	0.6%
27	Metered Outdoor Lighting	15	2,466	6,178	$1,235	$2	$1,237	$1,235	$17	$1,251	$0	0.0%	$15	1.2%
28	Traffic Signal Systems	15	515	17,536	$682	$1	$683	$682	$6	$688	$0	0.0%	$6	0.8%
29	*Subtotal Public Street Lighting*		12,675	109,168	$14,040	$12	$14,052	$14,040	$104	$14,144	$0	0.0%	$92	0.7%
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	$12	$14,058	$14,045	$104	$14,150	$0	0.0%	$92	0.7%
33	**Total Sales to Ultimate Customers**		854,859	23,244,285	$1,938,306	$2,776	$1,941,082	$1,938,306	$23,226	$1,961,533	$0	0.0%	$20,450	1.1%

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 2019[2] ($000)	EBA Deferral 2019[2] %
	(1)	(2)	(3)	(4)	(5)	(6)
	Residential					
1	Residential	1,3	$684,505		$6,749	1.0%
2	Residential-Optional TOD	2	$351		$3	1.0%
3	AGA/Revenue Credit	--	$33			
4	**Total Residential**		$684,889	$170,321	$6,752	1.0%
	Commercial & Industrial & OSPA					
5	General Service-Distribution	6	$494,681		$5,967	1.2%
6	General Service-Distribution-Energy TOD	6A	$34,227		$413	1.2%
7	General Service-Distribution-Demand TOD	6B	$346		$4	1.2%
8	*Subtotal Schedule 6*		$529,255	$161,024	$6,384	1.2%
9	General Service-Distribution > 1,000 kW	8	$167,313	$56,651	$2,246	1.3%
10	General Service-High Voltage	9	$284,876		$4,906	1.7%
11	General Service-High Voltage-Energy TOD	9A	$3,293		$57	1.7%
12	*Subtotal Schedule 9*		$288,169	$125,184	$4,963	1.7%
13	Irrigation	10	$13,210		$177	1.3%
14	Irrigation-Time of Day	10TOD	$1,286		$17	1.3%
15	*Subtotal Irrigation*		$14,496	$4,897	$194	1.3%
16	Electric Furnace	21	$476		$8	1.7%
17	General Service-Distribution-Small	23	$139,103	$37,646	$1,492	1.1%
18	Back-up, Maintenance, & Supplementary	31	$4,576		$79	1.7%
19	Contract 1	--	$27,959	$13,217	$335	1.2%
20	Contract 2	--	$35,063	$17,354	$688	2.0%
21	Contract 3	--	$30,035		$0	0.0%
22	AGA/Revenue Credit	--	$2,928			
23	**Total Commercial & Industrial & OSPA**		$1,239,372	$415,974	$16,389	1.3%
	Public Street Lighting					
24	Security Area Lighting	7	$2,999	$508	$20	0.7%
25	Street Lighting - Company Owned	11	$4,979	$844	$33	0.7%
26	Street Lighting - Customer Owned	12	$4,145	$702	$28	0.7%
27	Metered Outdoor Lighting	15	$1,235	$425	$17	1.4%
28	Traffic Signal Systems	15	$682	$159	$6	0.9%
29	*Subtotal Public Street Lighting*		$14,040	$2,638	$105	0.7%
30	Security Area Lighting-Contracts (PTL)	--	$1	$0		
31	AGA/Revenue Credit	--	$5	$0		
32	**Total Public Street Lighting**		$14,045	$2,638	$105	0.7%
33	**Total Sales to Ultimate Customers**		$1,938,306	$588,932	$23,246	1.2%

Note:
[1] Net Power Cost allocator from 2014 GRC, Docket No. 13-035-184.
[2] Including 2018 EBA deferral and 2017 EBA balance.

2019 EBA Deferral	$23,877
Balance of 2018 EBA	($631)
Target EBA Rev	$23,246
Avg %	1.2%
Adj	99.62%

Rocky Mountain Power
Exhibit RMP___(RMM-2)
Docket No. 19-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Billing Determinants

March 2019

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	Sch73 Adj	Revenue Net	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		$50,392,662				
Customer Charge - 3 Phase	14,094	$12.00	$169,128		$169,128				
Net Metering Facilities Charge	23,932								
First 400 kWh (May-Sept)	1,274,636,742	8.8498 ¢	$112,802,802	($354,477)	$112,448,325	0.13%	$146,183	1.07%	$1,203,197
Next 600 kWh (May-Sept)	1,040,456,011	11.5429 ¢	$120,098,797	($377,404)	$119,721,393	0.13%	$155,638	1.07%	$1,281,019
All add'l kWh (May-Sept)	358,873,906	14.4508 ¢	$51,860,150	($162,968)	$51,697,182	0.13%	$67,206	1.07%	$553,160
All kWh (Oct-Apr)									
First 400 kWh (Oct-Apr)	1,613,094,234	8.8498 ¢	*$142,755,614*	*($448,602)*	*$142,307,012*	0.13%	*$184,999*	1.07%	*$1,522,685*
All add'l kWh (Oct-Apr)	1,704,644,903	10.7072 ¢	*$182,519,739*	*($573,560)*	*$181,946,179*	0.13%	*$236,530*	1.07%	*$1,946,824*
Minimum 1 Phase	98,763	$8.00	$790,104		$790,104				
Minimum 3 Phase	166	$16.00	$2,656		$2,656				
Minimum Seasonal	0	$96.00	$0		$0				
kWh in Minimum	501,472								
kWh in Minimum - Summer	223,485								
kWh in Minimum - Winter	277,987								
Unbilled	0		$0		$0				
Total	5,992,207,269		$661,391,652	($1,917,011)	$659,474,641		$790,556		$6,506,885
Schedule No. 3- Residential Service - Low Income Lifeline Program									
Total Customer	370,465								
Customer Charge - 1 Phase	369,457	$6.00	$2,216,742		$2,216,742				
Customer Charge - 3 Phase	257	$12.00	$3,084		$3,084				
Net Metering Facilities Charge	0								
First 400 kWh (May-Sept)	47,435,117	8.8498 ¢	$4,197,913	($3,515)	$4,194,398	0.13%	$5,453	1.07%	$44,880
Next 600 kWh (May-Sept)	31,907,309	11.5429 ¢	$3,683,029	($3,084)	$3,679,945	0.13%	$4,784	1.07%	$39,375
All add'l kWh (May-Sept)	10,205,740	14.4508 ¢	$1,474,811	($1,235)	$1,473,576	0.13%	$1,916	1.07%	$15,767
All kWh (Oct-Apr)									
First 400 kWh (Oct-Apr)	64,598,419	8.8498 ¢	*$5,716,831*	*($4,787)*	*$5,712,044*	0.13%	*$7,426*	1.07%	*$61,119*
All add'l kWh (Oct-Apr)	54,308,077	10.7072 ¢	*$5,814,874*	*($4,870)*	*$5,810,004*	0.13%	*$7,553*	1.07%	*$62,167*
Minimum 1 Phase	751	$8.00	$6,008		$6,008				
Minimum 3 Phase	0	$16.00	$0		$0				
Minimum Seasonal	0	$96.00	$0		$0				
kWh in Minimum	4,249								
kWh in Minimum - Summer	2,043								
kWh in Minimum - Winter	2,206								
Unbilled	0		$0		$0				
Total	208,458,911		$23,113,292	($17,491)	$23,095,801		$27,131		$223,309
Schedule No. 2 - Residential Service - Optional Time-of-Day									
Total Customer	5,364								
Customer Charge - 1 Phase	5,243	$6.00	$31,458		$31,458				
Customer Charge - 3 Phase	0	$12.00	$0		$0				
Net Metering Facilities Charge	1,185								
On-Peak kWh (May - Sept)	280,149	4.3560 ¢	$12,203		$12,203				
Off-Peak kWh (May - Sept)	954,590	(1.6334) ¢	($15,592)		($15,592)				
First 400 kWh (May-Sept)	675,062	8.8498 ¢	$59,742	$0	$59,742	0.13%	$78	1.07%	$639
Next 600 kWh (May-Sept)	474,415	11.5429 ¢	$54,761	$0	$54,761	0.13%	$71	1.07%	$586
All add'l kWh (May-Sept)	185,128	14.4508 ¢	$26,752	$0	$26,752	0.13%	$35	1.07%	$286
All kWh (Oct-Apr)									
First 400 kWh (Oct-Apr)	912,816	8.8498 ¢	*$80,782*	*$0*	*$80,782*	0.13%	*$105*	1.07%	*$864*
All add'l kWh (Oct-Apr)	937,823	10.7072 ¢	*$100,415*	*$0*	*$100,415*	0.13%	*$131*	1.07%	*$1,074*
Minimum 1 Phase	121	$8.00	$968		$968				
Minimum 3 Phase	0	$16.00	$0		$0				
Minimum Seasonal	0	$96.00	$0		$0				
kWh in Minimum	428								
kWh in Minimum - Summer	118								
kWh in Minimum - Winter	310								
Unbilled	0		$0		$0				
Total	3,185,671		$351,489	$0	$351,489		$419		$3,450
Schedule No. 6 - Composite									
Customer Charge	156,864	$54.00	$8,470,675		$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)		($651,969)				
Facilities kW	*16,578,133*	*$4.04*	$66,975,657		$66,975,657				
All kW (May - Sept)	*7,568,683*	*$14.62*	$110,654,145	$0	$110,654,145	0.17%	$188,112	1.42%	$1,571,289
All kW (Oct - Apr)	*9,009,450*	*$10.91*	$98,293,100	$0	$98,293,100	0.17%	$167,098	1.42%	$1,395,762
All kWh	5,783,806,261								
kWh (May - Sept)	2,573,577,152	3.8127 ¢	$98,122,776	($84,550)	$98,038,226	0.17%	$166,665	1.42%	$1,392,143
kWh (Oct - Apr)	3,210,229,109	3.5143 ¢	$112,817,082	($97,212)	$112,719,870	0.17%	$191,624	1.42%	$1,600,622
Seasonal Service	0	$648.00	$0		$0				
Unbilled	0		$0		$0				
Total	5,783,806,261		$494,681,466	($181,762)	$494,499,704		$713,499		$5,959,816

Schedule No. 6B - Demand Time-of-Day Option - Composite

Customer Charge		438	$54.00	$23,652		$23,652				
All On-peak kW (May - Sept)		6,224								
All On-peak kW (Oct - Apr)		4,264								
Voltage Discount		0	($0.96)	$0		$0				
Facilities kW		*10,488*	*$4.04*	$42,372		$42,372				
All On-peak kW (May - Sept)		*6,224*	*$14.62*	$90,995	$0	$90,995	0.17%	$155	1.42%	$1,292
All On-peak kW (Oct - Apr)		*4,264*	*$10.91*	$46,520	$0	$46,520	0.17%	$79	1.42%	$661
All kWh		3,907,497								
kWh (May-Sept)		1,628,124	3.8127 ¢	$62,075	$0	$62,075	0.17%	$106	1.42%	$881
kWh (Oct-Apr)		2,279,373	3.5143 ¢	$80,104	$0	$80,104	0.17%	$136	1.42%	$1,137
Seasonal Service		0	$648.00	$0		$0				
Unbilled		0		$0		$0				
Total		3,907,497		$345,718	$0	$345,718		$475		$3,972
Schedule No. 6A - Energy Time-of-Day Option - Composite										
Customer Charge		27,307	$54.00	$1,474,578		$1,474,578				
Facilities kW (May - Sept)		918,610	$6.52	$5,989,337		$5,989,337				
Facilities kW (Oct - Apr)		1,059,783	$5.47	$5,797,013		$5,797,013				
Voltage Discount		39,296	($0.61)	($23,971)		($23,971)				
On-Peak kWh (May - Sept)		62,251,233	11.9266 ¢	$7,424,456	($661,433)	$6,763,023	0.26%	$17,584	2.16%	$146,081
Off-Peak kWh (May - Sept)		59,556,790	3.5908 ¢	$2,138,565	($190,521)	$1,948,044	0.26%	$5,065	2.16%	$42,078
On-Peak kWh (Oct - Apr)		90,625,426	9.9693 ¢	$9,034,721	($804,889)	$8,229,832	0.26%	$21,398	2.16%	$177,764
Off-Peak kWh (Oct - Apr)		79,597,650	3.0060 ¢	$2,392,705	($213,164)	$2,179,541	0.26%	$5,667	2.16%	$47,078
Unbilled		0		$0		$0				
Total		292,031,100		$34,227,404	($1,870,007)	$32,357,397		$49,713		$413,002
Schedule No. 7 - Security Area Lighting - Composite										
MERCURY VAPOR LAMPS										
4,000 Lumen Energy Only	29	24	$5.68	$136	$0	$136	0.08%	$0	0.67%	$1
7,000 Lumen	1	45,001	$16.38	$737,116	$0	$737,116	0.08%	$590	0.67%	$4,939
7,000 Lumen Energy Only	28	0	$8.05	$0	$0	$0	0.08%	$0	0.67%	$0
20,000 Lumen	2	10,830	$26.78	$290,027	$0	$290,027	0.08%	$232	0.67%	$1,943
SODIUM VAPOR LAMPS										
5,600 Lumen New Pole	3	3,563	$14.60	$52,020	$0	$52,020	0.08%	$42	0.67%	$349
5,600 Lumen No New Pole	4	1,746	$12.23	$21,354	$0	$21,354	0.08%	$17	0.67%	$143
9,500 Lumen New Pole	5	23,403	$15.47	$362,044	$0	$362,044	0.08%	$290	0.67%	$2,426
9,500 Lumen No New Pole	6	23,123	$13.31	$307,767	$0	$307,767	0.08%	$246	0.67%	$2,062
16,000 Lumen New Pole	7	2,646	$19.46	$51,491	$0	$51,491	0.08%	$41	0.67%	$345
16,000 Lumen No New Pole	8	2,564	$17.13	$43,921	$0	$43,921	0.08%	$35	0.67%	$294
22,000 Lumen	9	114	$21.07	$2,402	$0	$2,402	0.08%	$2	0.67%	$16
27,500 Lumen New Pole	10	3,134	$23.51	$73,680	$0	$73,680	0.08%	$59	0.67%	$494
27,500 Lumen No New Pole	11	4,178	$21.23	$88,699	$0	$88,699	0.08%	$71	0.67%	$594
50,000 Lumen New Pole	12	1,248	$28.30	$35,318	$0	$35,318	0.08%	$28	0.67%	$237
50,000 Lumen No New Pole	13	2,456	$25.99	$63,831	$0	$63,831	0.08%	$51	0.67%	$428
SODIUM VAPOR FLOOD LAMPS										
16,000 Lumen New Pole	14	4,670	$19.46	$90,878	$0	$90,878	0.08%	$73	0.67%	$609
16,000 Lumen No New Pole	15	4,976	$17.13	$85,239	$0	$85,239	0.08%	$68	0.67%	$571
27,500 Lumen New Pole	16	1,102	$23.51	$25,908	$0	$25,908	0.08%	$21	0.67%	$174
27,500 Lumen No New Pole	17	1,570	$21.23	$33,331	$0	$33,331	0.08%	$27	0.67%	$223
50,000 Lumen New Pole	18	9,734	$28.30	$275,472	$0	$275,472	0.08%	$220	0.67%	$1,846
50,000 Lumen No New Pole	19	11,772	$25.99	$305,954	$0	$305,954	0.08%	$245	0.67%	$2,050
METAL HALIDE LAMPS										
12,000 Lumen New Pole	20	0	$29.40	$0	$0	$0	0.08%	$0	0.67%	$0
12,000 Lumen No New Pole	21	265	$21.79	$5,774	$0	$5,774	0.08%	$5	0.67%	$39
19,500 Lumen New Pole	22	110	$34.34	$3,777	$0	$3,777	0.08%	$3	0.67%	$25
19,500 Lumen No New Pole	23	97	$27.43	$2,661	$0	$2,661	0.08%	$2	0.67%	$18
32,000 Lumen New Pole	24	469	$36.69	$17,208	$0	$17,208	0.08%	$14	0.67%	$115
32,000 Lumen No New Pole	25	630	$29.72	$18,724	$0	$18,724	0.08%	$15	0.67%	$125
107,000 Lumen New Pole	26	24	$57.58	$1,382	$0	$1,382	0.08%	$1	0.67%	$9
107,000 Lumen No New Pole	27	60	$49.10	$2,946	$0	$2,946	0.08%	$2	0.67%	$20
Subtotal		159,509		$2,999,060	$0	$2,999,060		$2,399		$20,094
kWh Included		12,440,931								
Unbilled		0		$0		$0				
Customers		8,046								
Total (kWh)		12,440,931		$2,999,060	$0	$2,999,060		$2,399		$20,094
Schedule No. 8 - Composite										
Customer Charge		3,282	$70.00	$229,740		$229,740				
Facilities kW		5,010,201	$4.76	$23,848,557		$23,848,557				
On-Peak kW (May - Sept)		2,097,818	$15.56	$32,642,048	$0	$32,642,048	0.18%	$58,756	1.55%	$505,952
On-Peak kW (Oct - Apr)		2,761,958	$11.19	$30,906,310	$0	$30,906,310	0.18%	$55,631	1.55%	$479,048
Voltage Discount		2,132,830	($1.13)	($2,410,098)		($2,410,098)				
On-Peak kWh (May - Sept)		260,094,535	5.0474 ¢	$13,128,012	$0	$13,128,012	0.18%	$23,630	1.55%	$203,484
On-Peak kWh (Oct - Apr)		625,992,212	3.9511 ¢	$24,733,578	$0	$24,733,578	0.18%	$44,520	1.55%	$383,370
Off-Peak kWh		1,300,960,579	3.4002 ¢	$44,235,262	$0	$44,235,262	0.18%	$79,623	1.55%	$685,647
Unbilled		0		$0		$0				
Total		2,187,047,326		$167,313,409	$0	$167,313,409		$262,161		$2,257,501
Schedule No. 9 - Composite										
Customer Charge		1,791	$259.00	$463,869		$463,869				
Facilities kW		9,053,509	$2.22	$20,098,790		$20,098,790				
On-Peak kW (May - Sept)		3,715,246	$13.96	$51,864,834	$0	$51,864,834	0.22%	$114,103	1.86%	$964,686
On-Peak kW (Oct - Apr)		5,150,021	$9.47	$48,770,699	$0	$48,770,699	0.22%	$107,296	1.86%	$907,135
On-Peak kWh (May-Sept)		507,349,132	4.6531 ¢	$23,607,462	$0	$23,607,462	0.22%	$51,936	1.86%	$439,099
On-Peak kWh (Oct-Apr)		1,382,941,034	3.4989 ¢	$48,387,724	$0	$48,387,724	0.22%	$106,453	1.86%	$900,012
Off-Peak kWh		3,137,145,375	2.9225 ¢	$91,683,074	$0	$91,683,074	0.22%	$201,703	1.86%	$1,705,305
Unbilled		0		$0		$0				
Total		5,027,435,541		$284,876,452	$0	$284,876,452		$581,490		$4,916,237

Schedule No. 9A - Energy TOD - Composite									
Customer Charge	108	$259.00	$27,972		$27,972				
Facilities Charge per kW	235,118	$2.22	$521,962		$521,962				
On-Peak kWh	23,805,248	8.6029 ¢	$2,047,942	$0	$2,047,942	0.25%	$5,120	2.07%	$42,392
Off-Peak kWh	18,785,533	3.6981 ¢	$694,708	$0	$694,708	0.25%	$1,737	2.07%	$14,380
Unbilled	0		$0		$0				
Total	42,590,781		$3,292,584	$0	$3,292,584		$6,857		$56,773
Schedule No. 10 - Irrigation									
Annual Cust. Serv. Chg. - Primary	6	$125.00	$750		$750				
Annual Cust. Serv. Chg. - Secondary	2,778	$38.00	$105,577		$105,577				
Monthly Cust. Serv. Chg.	12,565	$14.00	$175,910		$175,910				
All On-Season kW	323,633	$7.33	$2,372,230	$0	$2,372,230	0.16%	$3,796	1.38%	$32,737
Voltage Discount	10,067	($2.05)	($20,637)		($20,637)				
First 30,000 kWh	71,130,178	7.2971 ¢	$5,190,440	$0	$5,190,440	0.16%	$8,305	1.38%	$71,628
All add'l kWh	51,830,436	5.3936 ¢	$2,795,526	$0	$2,795,526	0.16%	$4,473	1.38%	$38,578
Total On Season	122,960,614		$10,619,796	$0	$10,619,796		$16,573		$142,943
Post Season									
Customer Charge	5,886	$14.00	$82,404		$82,404				
kWh	50,172,778	4.9983 ¢	$2,507,786	$0	$2,507,786	0.16%	$4,012	1.38%	$34,607
Total Post Season	50,172,778		$2,590,190	$0	$2,590,190		$4,012		$34,607
Unbilled	0		$0		$0				
TOTAL RATE 10	173,133,392		$13,209,986	$0	$13,209,986		$20,586		$177,551
Schedule No. 10-TOD									
Annual Cust. Serv. Chg. - Primary	5	$125.00	$625		$625				
Annual Cust. Serv. Chg. - Secondary	256	$38.00	$9,728		$9,728				
Monthly Cust. Serv. Chg.	1,143	$14.00	$16,002		$16,002				
All On-Season kW	37,541	$7.33	$275,176	$0	$275,176	0.16%	$440	1.38%	$3,797
Voltage Discount kW	1,037	($2.05)	($2,126)		($2,126)				
On-Peak kWh	2,262,299	14.4164 ¢	$326,142	$0	$326,142	0.16%	$522	1.38%	$4,501
Off-Peak kWh	8,574,215	4.1542 ¢	$356,190	$0	$356,190	0.16%	$570	1.38%	$4,915
Total On Season	10,836,514		$981,737	$0	$981,737		$1,532		$13,214
Post Season									
Customer Charge	570	$14.00	$7,980		$7,980				
kWh	5,920,094	4.9983 ¢	$295,904	$0	$295,904	0.16%	$473	1.38%	$4,083
Total Post Season	5,920,094		$303,884	$0	$303,884		$473		$4,083
Unbilled	0		$0		$0				
TOTAL RATE 10-TOD	16,756,608		$1,285,621	$0	$1,285,621		$2,005		$17,297
Schedule No. 11 - Street Lighting - Company-Owned System									
Sodium Vapor Lamps (HPS)									
5,600 Lumen - Functional	34,757	$11.80	$410,133	$0	$410,133	0.08%	$328	0.67%	$2,748
9,500 Lumen - Functional	218,738	$12.78	$2,795,472	$0	$2,795,472	0.08%	$2,236	0.67%	$18,730
9,500 Lumen - Functional @ 90%	132	$11.50	$1,518	$0	$1,518	0.08%	$1	0.67%	$10
9,500 Lumen - S1	409	$46.54	$19,035	$0	$19,035	0.08%	$15	0.67%	$128
9,500 Lumen - S2	60	$38.05	$2,283	$0	$2,283	0.08%	$2	0.67%	$15
16,000 Lumen - Functional	21,158	$16.94	$358,417	$0	$358,417	0.08%	$287	0.67%	$2,401
16,000 Lumen - Functional @ 90%	96	$15.25	$1,464	$0	$1,464	0.08%	$1	0.67%	$10
16,000 Lumen - S1	2,421	$47.83	$115,796	$0	$115,796	0.08%	$93	0.67%	$776
16,000 Lumen - S2	886	$39.34	$34,855	$0	$34,855	0.08%	$28	0.67%	$234
27,500 Lumen - Functional	26,178	$21.14	$553,403	$0	$553,403	0.08%	$443	0.67%	$3,708
27,500 Lumen - Functional @ 90%	12	$19.03	$228	$0	$228	0.08%	$0	0.67%	$2
27,500 Lumen - S1	1,253	$51.48	$64,504	$0	$64,504	0.08%	$52	0.67%	$432
27,500 Lumen - S2	0	$43.01	$0	$0	$0	0.08%	$0	0.67%	$0
50,000 Lumen - Functional	11,406	$26.02	$296,784	$0	$296,784	0.08%	$237	0.67%	$1,988
125,000 Lumen	0	$51.54	$0	$0	$0	0.08%	$0	0.67%	$0
Metal Halide Lamps (MH)									
9,000 Lumen - S1	36	$48.74	$1,755	$0	$1,755	0.08%	$1	0.67%	$12
9,000 Lumen - S2	602	$40.27	$24,243	$0	$24,243	0.08%	$19	0.67%	$162
12,000 Lumen - Functional	127	$20.13	$2,557	$0	$2,557	0.08%	$2	0.67%	$17
12,000 Lumen - S1	0	$50.65	$0	$0	$0	0.08%	$0	0.67%	$0
12,000 Lumen - S2	1,598	$42.17	$67,388	$0	$67,388	0.08%	$54	0.67%	$451
19,500 Lumen - Functional	386	$22.13	$8,542	$0	$8,542	0.08%	$7	0.67%	$57
19,500 Lumen - S1	41	$53.69	$2,201	$0	$2,201	0.08%	$2	0.67%	$15
19,500 Lumen - S2	365	$45.20	$16,498	$0	$16,498	0.08%	$13	0.67%	$111
32,000 Lumen - Functional	61	$25.78	$1,573	$0	$1,573	0.08%	$1	0.67%	$11
32,000 Lumen - S1	0	$55.33	$0	$0	$0	0.08%	$0	0.67%	$0
32,000 Lumen - S2	0	$46.86	$0	$0	$0	0.08%	$0	0.67%	$0
Mercury Vapor Lamps (No New Service) (MV)									
4,000 Lumen	3,279	$11.09	$36,364	$0	$36,364	0.08%	$29	0.67%	$244
7,000 Lumen	9,152	$13.83	$126,572	$0	$126,572	0.08%	$101	0.67%	$848
10,000 Lumen	186	$19.40	$3,608	$0	$3,608	0.08%	$3	0.67%	$24
10,000 Lumen @ 90%	0	$17.46	$0	$0	$0	0.08%	$0	0.67%	$0
20,000 Lumen	996	$24.43	$24,332	$0	$24,332	0.08%	$19	0.67%	$163
Incandescent Lamps (No New Service) (INC)									
500 Lumen	0	$11.99	$0	$0	$0	0.08%	$0	0.67%	$0
600 Lumen	145	$4.24	$615	$0	$615	0.08%	$0	0.67%	$4
2,500 Lumen	32	$17.11	$548	$0	$548	0.08%	$0	0.67%	$4
4,000 Lumen	162	$20.43	$3,310	$0	$3,310	0.08%	$3	0.67%	$22
6,000 Lumen	161	$23.82	$3,835	$0	$3,835	0.08%	$3	0.67%	$26
10,000 Lumen	24	$31.47	$755	$0	$755	0.08%	$1	0.67%	$5
Fluorescent Lamps (No New Service) (FLOUR)									
21,000 Lumen	12	$27.85	$334	$0	$334	0.08%	$0	0.67%	$2
Special Service (No New Service)									
50,000 Lumen - Flood	12	$39.04	$468	$0	$468	0.08%	$0	0.67%	$3
Subtotal	334,883		$4,979,390	$0	$4,979,390		$3,984		$33,362
kWh Included	16,496,197								
Customers	809								
Unbilled	0		$0		$0				

Total	16,496,197		$4,979,390	$0	$4,979,390		$3,984		$33,362
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	$189,292	0.08%	$151	0.67%	$1,268
9,500 Lumen	159,006	$2.50	$397,515	$0	$397,515	0.08%	$318	0.67%	$2,663
16,000 Lumen	134,332	$3.66	$491,655	$0	$491,655	0.08%	$393	0.67%	$3,294
27,500 Lumen	48,293	$6.52	$314,870	$0	$314,870	0.08%	$252	0.67%	$2,110
50,000 Lumen	65,553	$10.02	$656,841	$0	$656,841	0.08%	$525	0.67%	$4,401
Metal Halide Lamps									
9,000 Lumen	6,583	$2.55	$16,787	$0	$16,787	0.08%	$13	0.67%	$112
12,000 Lumen	18,818	$4.46	$83,928	$0	$83,928	0.08%	$67	0.67%	$562
19,500 Lumen	28,281	$6.17	$174,494	$0	$174,494	0.08%	$140	0.67%	$1,169
32,000 Lumen	27,914	$9.77	$272,720	$0	$272,720	0.08%	$218	0.67%	$1,827
Non-listed Luminaries kWh	10,059,553	6.5279 ¢	$656,678	$0	$656,678	0.08%	$525	0.67%	$4,400
Subtotal kWh	49,653,570		$3,254,780	$0	$3,254,780		$2,604		$21,807
Unbilled									
Total	49,653,570		$3,254,780	$0	$3,254,780		$2,604		$21,807
Customer	519								
2a - Partial Maintenance (No New Service)									
Incandescent Lamps									
2,500 Lumen or Less	76	$8.96	$681	$0	$681	0.08%	$1	0.67%	$5
4,000 Lumen	91	$12.19	$1,109	$0	$1,109	0.08%	$1	0.67%	$7
Mercury Vapor Lamps									
4,000 Lumen	47	$4.64	$218	$0	$218	0.08%	$0	0.67%	$1
7,000 Lumen	546	$7.00	$3,822	$0	$3,822	0.08%	$3	0.67%	$26
20,000 Lumen	140	$13.33	$1,866	$0	$1,866	0.08%	$1	0.67%	$13
54,000 Lumen	0	$28.38	$0	$0	$0	0.08%	$0	0.67%	$0
High Pressure Sodium Vapor Lamps									
5,600 Lumen	34,609	$4.08	$141,205	$0	$141,205	0.08%	$113	0.67%	$946
9,500 Lumen	15,632	$5.37	$83,944	$0	$83,944	0.08%	$67	0.67%	$562
9,500 Lumen - Decorative	8,817	$6.96	$61,366	$0	$61,366	0.08%	$49	0.67%	$411
16,000 Lumen	2,548	$6.52	$16,613	$0	$16,613	0.08%	$13	0.67%	$111
16,000 Lumen - Decorative	799	$8.27	$6,608	$0	$6,608	0.08%	$5	0.67%	$44
22,000 Lumen	0	$8.26	$0	$0	$0	0.08%	$0	0.67%	$0
27,500 Lumen	5,601	$9.59	$53,714	$0	$53,714	0.08%	$43	0.67%	$360
27,500 Lumen - Decorative	143	$11.93	$1,706	$0	$1,706	0.08%	$1	0.67%	$11
50,000 Lumen	10,133	$14.00	$141,862	$0	$141,862	0.08%	$113	0.67%	$950
50,000 Lumen - Decorative	157	$15.56	$2,443	$0	$2,443	0.08%	$2	0.67%	$16
Metal Halide Lamps									
9,000 Lumen - Decorative	702	$9.19	$6,451	$0	$6,451	0.08%	$5	0.67%	$43
12,000 Lumen	1,617	$13.57	$21,943	$0	$21,943	0.08%	$18	0.67%	$147
12,000 Lumen - Decorative	225	$11.09	$2,495	$0	$2,495	0.08%	$2	0.67%	$17
19,500 Lumen	518	$13.71	$7,102	$0	$7,102	0.08%	$6	0.67%	$48
19,500 Lumen - Decorative	6,034	$14.13	$85,260	$0	$85,260	0.08%	$68	0.67%	$571
32,000 Lumen	544	$14.58	$7,932	$0	$7,932	0.08%	$6	0.67%	$53
32,000 Lumen - Decorative	669	$15.79	$10,564	$0	$10,564	0.08%	$8	0.67%	$71
Fluorescent Lamps									
1,000 Lumen	0	$3.75	$0	$0	$0	0.08%	$0	0.67%	$0
21,800 Lumen	83	$13.92	$1,155	$0	$1,155	0.08%	$1	0.67%	$8
Subtotal kWh	5,219,065		$660,059	$0	$660,059		$528		$4,422
Unbilled									
Total	5,219,065		$660,059	$0	$660,059		$528		$4,422
Customer	221								
2b - Full Maintenance (No New Service)									
Incandescent Lamps									
6,000 Lumen	36	$17.73	$638	$0	$638	0.08%	$1	0.67%	$4
10,000 Lumen	12	$23.40	$281	$0	$281	0.08%	$0	0.67%	$2
Mercury Vapor Lamps									
7,000 Lumen	42	$8.03	$337	$0	$337	0.08%	$0	0.67%	$2
20,000 Lumen	0	$15.30	$0	$0	$0	0.08%	$0	0.67%	$0
54,000 Lumen	96	$32.48	$3,118	$0	$3,118	0.08%	$2	0.67%	$21
Sodium Vapor Lamps									
5,600 Lumen	4,275	$4.68	$20,007	$0	$20,007	0.08%	$16	0.67%	$134
9,500 Lumen	14,686	$6.16	$90,466	$0	$90,466	0.08%	$72	0.67%	$606
16,000 Lumen	1,259	$7.47	$9,405	$0	$9,405	0.08%	$8	0.67%	$63
22,000 Lumen	0	$9.44	$0	$0	$0	0.08%	$0	0.67%	$0
27,500 Lumen	2,408	$10.99	$26,464	$0	$26,464	0.08%	$21	0.67%	$177
50,000 Lumen	1,967	$16.02	$31,511	$0	$31,511	0.08%	$25	0.67%	$211
Metal Halide Lamps									
12,000 Lumen	1,188	$15.58	$18,509	$0	$18,509	0.08%	$15	0.67%	$124
19,500 Lumen	724	$15.73	$11,389	$0	$11,389	0.08%	$9	0.67%	$76
32,000 Lumen	881	$16.72	$14,730	$0	$14,730	0.08%	$12	0.67%	$99
107,000 Lumen	96	$33.05	$3,173	$0	$3,173	0.08%	$3	0.67%	$21
Subtotal kWh	1,644,140		$230,028	$0	$230,028		$184		$1,541
Unbilled									
Total	1,644,140		$230,028	$0	$230,028		$184		$1,541
Customer	99								
kWh Street Lighting	56,516,774		$4,144,867	$0	$4,144,867		$3,316		$27,771
Customers	839								
Unbilled			$0		$0				
Total	56,516,774		$4,144,867	$0	$4,144,867		$3,316		$27,771
Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite									
Annual Facility Charge	20,286	$11.00	$223,146		$223,146				
Annual Customer Charge	497	$72.50	$36,033		$36,033				
Annual Minimum Charge	0.0	$127.50	$0		$0				
Monthly Customer Charge	6,182	$6.20	$38,328		$38,328				

All kWh	17,536,445	5.3437 ¢	$937,095	$0	$937,095	0.21%	$1,968	1.80%	$16,868
Unbilled	0		$0		$0				
Total	17,536,445		$1,234,602	$0	$1,234,602		$1,968		$16,868
Schedule 15.2 - Traffic Signal Systems - Composite									
Customer Charge	29,596	$5.50	$162,778		$162,778				
All kWh	6,177,947	8.4049 ¢	$519,250	$0	$519,250	0.14%	$727	1.21%	$6,283
Unbilled	0		$0		$0				
Total	6,177,947		$682,028	$0	$682,028		$727		$6,283
Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial									
Primary Voltage									
Customer Charge	36	$127.00	$4,572		$4,572				
Charge per kW (Facilities)	10,893	$4.30	$46,840		$46,840				
First 100,000 kWh	423,833	6.8447 ¢	$29,010	$0	$29,010	0.45%	$131	3.76%	$1,091
All add'l kWh	0	5.7472 ¢	$0	$0	$0	0.45%	$0	3.76%	$0
Unbilled	0		$0		$0				
Subtotal	423,833		$80,422	$0	$80,422		$131		$1,091
44KV or Higher									
Customer Charge	24	$127.00	$3,048		$3,048				
Charge per kW (Facilities)	47,371	$4.30	$203,695		$203,695				
First 100,000 kWh	2,660,898	5.3851 ¢	$143,292	$0	$143,292	0.45%	$645	3.76%	$5,388
All add'l kWh	963,969	4.7169 ¢	$45,469	$0	$45,469	0.45%	$205	3.76%	$1,710
Unbilled	0		$0		$0				
Subtotal	3,624,867		$395,504	$0	$395,504		$849		$7,097
Total	4,048,700		$475,926	$0	$475,926		$980		$8,188
Schedule No. 23 - Composite									
Customer Charge	992,018	$10.00	$9,920,180		$9,920,180				
kW over 15 (May - Sept)	387,746	$8.65	$3,354,003	$0	$3,354,003	0.14%	$4,696	1.16%	$38,906
kW over 15 (Oct - Apr)	347,761	$8.70	$3,025,521	$0	$3,025,521	0.14%	$4,236	1.16%	$35,096
Voltage Discount	7,029	($0.48)	($3,374)		($3,374)				
First 1,500 kWh (May - Sept)	295,977,608	11.7336 ¢	$34,728,829	($58,044)	$34,670,785	0.14%	$48,539	1.16%	$402,181
All Add'l kWh (May - Sept)	309,000,008	6.5783 ¢	$20,326,948	($33,973)	$20,292,975	0.14%	$28,410	1.16%	$235,399
First 1,500 kWh (Oct - Apr)	424,820,226	10.8000 ¢	$45,880,584	($76,682)	$45,803,902	0.14%	$64,125	1.16%	$531,325
All Add'l kWh (Oct - Apr)	361,090,369	6.0567 ¢	$21,870,160	($36,554)	$21,833,606	0.14%	$30,567	1.16%	$253,270
Seasonal Service	0	$120.00	$0		$0				
Unbilled	0		$0		$0				
Total	1,390,888,211		$139,102,851	($205,253)	$138,897,598		$180,573		$1,496,177
Schedule No.31 - Composite									
Secondary Voltage									
Customer Charge per month	0	$133.00	$0		$0				
Facilities Charge, per kW month	0	$5.60	$0		$0				
Back-up Power Charge									
Regular, per On-Peak kW day	0								
May - Sept	0	$0.88	$0		$0				
Oct - Apr	0	$0.62	$0		$0				
Maintenance, per On-Peak kW day	0								
May - Sept	0	$0.440	$0		$0				
Oct - Apr	0	$0.310	$0		$0				
Excess Power, per kW month	0								
May - Sept	0	$40.81	$0		$0				
Oct - Apr	0	$32.04	$0		$0				
Primary Voltage									
Customer Charge per month	24	$605.00	$14,520		$14,520				
Facilities Charge, per kW month	38,791	$4.46	$173,008		$173,008				
Back-up Power Charge									
Regular, per On-Peak kW day	195,683								
May - Sept	79,030	$0.86	$67,966		$67,966				
Oct - Apr	116,653	$0.60	$69,992		$69,992				
Maintenance, per On-Peak kW day	24,254								
May - Sept	24,254	$0.430	$10,429		$10,429				
Oct - Apr	0	$0.300	$0		$0				
Excess Power, per kW month	30								
May - Sept	0	$38.54	$0		$0				
Oct - Apr	30	$29.77	$893		$893				
Transmission Voltage									
Customer Charge per month	24	$678.00	$16,272		$16,272				
Facilities Charge, per kW month	153,429	$2.63	$403,518		$403,518				
Back-up Power Charge									
Regular, per On-Peak kW day	391,585								
May - Sept	239,920	$0.76	$182,339		$182,339				
Oct - Apr	151,665	$0.51	$77,349		$77,349				
Maintenance, per On-Peak kW day	0								
May - Sept	0	$0.380	$0		$0				
Oct - Apr	0	$0.255	$0		$0				
Excess Power, per kW month	0								
May - Sept	0	$32.35	$0		$0				
Oct - Apr	0	$23.36	$0		$0				
Subtotal			$1,016,286	$0	$1,016,286		$0		$0
Supplemental billed at Schedule 6/8/9 rate									
Schedule 8									
Facilities kW	16,065	$4.76	$76,469		$76,469				
On-Peak kW (May - Sept)	0	$15.56	$0	$0	$0	0.18%	$0	1.55%	$0
On-Peak kW (Oct - Apr)	16,065	$11.19	$179,767	$0	$179,767	0.18%	$324	1.55%	$2,786
Voltage Discount	16,065	($1.13)	($18,153)		($18,153)				
On-Peak kWh (May - Sept)	1,044,794	5.0474 ¢	$52,735	$0	$52,735	0.18%	$95	1.55%	$817
On-Peak kWh (Oct - Apr)	3,934,668	3.9511 ¢	$155,463	$0	$155,463	0.18%	$280	1.55%	$2,410
Off-Peak kWh	5,030,285	3.4002 ¢	$171,040	$0	$171,040	0.18%	$308	1.55%	$2,651

Schedule 9									
Facilities kW	103,313	$2.22	$229,355		$229,355				
On-Peak kW (May - Sept)	49,491	$13.96	$690,894	$0	$690,894	0.22%	$1,520	1.86%	$12,851
On-Peak kW (Oct - Apr)	50,080	$9.47	$474,258	$0	$474,258	0.22%	$1,043	1.86%	$8,821
On-Peak kWh (May-Sept)	7,647,176	4.6531 ¢	$355,831	$0	$355,831	0.22%	$783	1.86%	$6,618
On-Peak kWh (Oct-Apr)	10,898,121	3.4989 ¢	$381,314	$0	$381,314	0.22%	$839	1.86%	$7,092
Off-Peak kWh	27,727,401	2.9225 ¢	$810,333	$0	$810,333	0.22%	$1,783	1.86%	$15,072
Subtotal			$3,559,306	$0	$3,559,306		$6,974		$59,119
Unbilled	0		$0		$0				
Total (Aggregated)	56,282,445		$4,575,592	$0	$4,575,592		$6,974		$59,119
Contract 1									
Fixed Customer Charge	12		$2,455		$2,455				
Customer Charge			$1,757,447.77		$1,757,447.77				
kW High Load Hours	949,050		$9,607,156	$0	$9,607,156	0.15%	$14,411	1.28%	$122,972
kWh High Load Hours	237,232,647		$8,613,813	$0	$8,613,813	0.15%	$12,921	1.28%	$110,257
kWh Low Load Hours	298,488,523		$7,977,879	$0	$7,977,879	0.15%	$11,967	1.28%	$102,117
Total	535,721,170		$27,958,751	$0	$27,958,751		$39,298		$335,345
Contract 2									
Customer Charge	12								
Interruptible kWh	795,798,676		$35,062,890	$0	$35,062,890	0.23%	$80,645	1.96%	$687,233
Total	795,798,676		$35,062,890	$0	$35,062,890		$80,645		$687,233
Contract 3									
Customer Charge	12		$8,136		$8,136				
Facilities Charge per kW - Back-Up	422,498		$921,045		$921,045				
kW Back-Up									
Regular, per On-Peak kW day	3,435,490								
May - Sept	3,253,488		$1,673,920		$1,673,920				
Oct - Apr	182,002		$93,640		$93,640				
Maintenance, per On-Peak kW day	0								
May - Sept			$0		$0				
Oct - Apr			$0		$0				
Excess Power, per kW month	0								
May - Sept			$0		$0				
Oct - Apr			$0		$0				
kW Supplemental									
On-Peak kW (May - Sept)	24,807		$346,306	$0	$346,306		$0		$0
On-Peak kW (Oct - Apr)	765,402		$7,248,357	$0	$7,248,357		$0		$0
kWh Supplemental									
On-Peak kWh (May-Sept)	22,796,861	¢	$1,060,761	$0	$1,060,761		$0		$0
On-Peak kWh (Oct-Apr)	204,228,863	¢	$7,145,764	$0	$7,145,764		$0		$0
Off-Peak kWh	394,783,609	¢	$11,537,551	$0	$11,537,551		$0		$0
Total	621,809,333		$30,035,480	$0	$30,035,480		$0		$0
Lighting Contract - Post Top Lighting - Composite									
Energy Only Res	60	$2.18	$131		$131				
Energy Only Non-Res	207	$2.1858	$452		$452				
Subtotal	267		$583	$0	$583				
KWH Included	7,737								
Customers	5								
Unbilled	0								
Total	7,737		$583	$0	$583		$0		$0
Annual Guarantee Adjustment									
Residential			$33,040		$33,040				
Commercial			$2,726,578		$2,726,578				
Industrial			($5,447)		($5,447)				
Irrigation			$206,563		$206,563				
Public Street & Highway Lighting			$4,662		$4,662				
Other Sales Public Authorities			$0		$0				
Total AGA			$2,965,396	$0	$2,965,396		$0		$0
TOTAL - ALL CLASSES	23,244,284,922		$1,938,306,489	($4,191,523)	$1,934,114,966		$2,775,757		$23,226,230

Rocky Mountain Power
Exhibit RMP___(RMM-3)
Docket No. 19-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariffs

March 2019

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

EBA FERC 501 Adjustments
FERC Sub 5013500
SAP 515200 – Natural Gas Consumed
Gadsby Related Portion of 515200 is transferred to FERC 547(Fuel-Other Generation)
SAP 515220 – Natural Gas Swaps
Gadsby Related portion of 515220 is transferred to FERC 547(Fuel-Other Generation)
SAP 505917– I/C Nat Gas Cons Ker. This SAP account is transferred to FERC 547(Fuel-Other Generation)

FERC 447 – Sales For Resale
FERC Sub 4471400
SAP 301406 – Short-term Firm Wholesale
Non Transalta Sales (Include)
SAP 301409 – Trading Sales Netted-Estimate (Exclude)
SAP 301410 – Trade Sales Netted (Include)
SAP 301411 – Bookout Sales Netted (Include)
SAP 301412 – Bookout Sales Netted-Estimate (Exclude)
SAP 302751 – I/C ST Firm Whls-Sie (Include)
SAP 302752 – I/C S-T Firm Wholesale Sales-Nevada Pwr (Include)
SAP 302771 – I/C Line Loss Trading Revenue-Sierra Pac (Include)
SAP 302772 – I/C Line Loss-Nevada (Include)
SAP 303028 – Line Loss W/S Trading (Include)
SAP 303100 – Transmission Loss Charge Pass-Through (Exclude)
SAP 303109 – Transmission Line Loss Rev – Subject to Refund (Include)
~~SAP 301409 – Trading Sales Netted – Estimates (Exclude)~~
FERC Sub 4471300
SAP 301405 – FIRM Sales (Include)
FERC Sub 4476100
SAP 304101 – Bookouts Netted – Gain (Include)
SAP 304102 – Bookouts Netted – Estimates (Exclude)
FERC Sub 4476200
SAP 304201 – Trading Net- Gains (Include)
FERC Sub 4472000 – Sales for Resale Estimates (Exclude)
FERC Sub 4475000
SAP 301408 – Off-System Non Firm (Include)
FERC Sub 4479000 – Transmission Services - Utah FERC Customers, Wyo-Pacific Cheyenne (Exclude)
FERC Sub 4471000 – Onsystem Firm - Utah FERC Customers, Wyo-Pacific Cheyenne, Brigham City, Portland General Electric (Exclude)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

EBA FERC 447 Adjustments

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

FERC 555 – Purchased Power

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

FERC 555 – Purchased Power (continued)

FERC Sub 5552200,2300,2400 – REC Purchases, RPS Compliance Purchases (Exclude)
FERC Sub 5552500
SAP 505185 – Net Metering Export Credit-UT Solar (Include)
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 5552700
SAP 505195 – Purchased Power-UT Subscriber Solar
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)

(continued)

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

FERC 547 Fuel – Other Generation

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

EBA FERC 547 Adjustments

FERC Sub 5013500

SAP 515200 – Natural Gas Consumed

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

SAP 515220 – Natural Gas Swaps

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

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

FERC 456.1 Revenues from Transmission of Electricity by Others

FERC Sub 4561100

SAP 505961 – Transmission Imbalance Penalty Revenue – Load (Exclude)
SAP 505963 – Transmission Imbalance Penalty Revenue –Pt to Pt (Exclude)
SAP (All Other) – Primary Delivery and Distribution Sub Charges, Ancillary Revenue, Use of Facility – Revenue, Transmission Resales to Other Parties, Transmission Revenue Unreserved Use Charges Transmission Revenue – Deferral Fees (Include)
SAP 302081 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)
SAP 302082 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)
SAP 302091 - I/C Anc Rev Sch 2-Reactive-Sierra Pac (Include)
SAP 302092 - I/C Anc Rev Sch 2-Reactive-Nevada Pwr (Include)
SAP 302821 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)
SAP 302822 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)
SAP 302831 – I/C Other Wheeling Revenue-Sierra Pac (Include)
SAP 302832 – I/C Other Wheeling Revenue-Nevada (Include)

FERC Sub 4561600

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

FERC Sub 4561910

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

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

FERC Sub 4561930

SAP 301922 – Non-Firm Wheeling Revenue (Include)

FERC Sub 4561990

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

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ELECTRIC SERVICE SCHEDULE NO. 94 – C~~c~~ontinued

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.

Schedule 1	1.07~~0.13~~%
Schedule 2	1.07~~0.13~~%
Schedule 2E	1.07~~0.13~~%
Schedule 3	1.07~~0.13~~%
Schedule 6	1.42~~0.17~~%
Schedule 6A	2.16~~0.26~~%
Schedule 6B	1.42~~0.17~~%
Schedule 7*	0.67~~0.08~~%
Schedule 8	1.55~~0.18~~%
Schedule 9	1.86~~0.22~~%
Schedule 9A	2.07~~0.25~~%
Schedule 10	1.38~~0.16~~%
Schedule 11*	0.67~~0.08~~%
Schedule 12*	0.67~~0.08~~%
Schedule 15 (Traffic and Other Signal Systems)	1.21~~0.14~~%
Schedule 15 (Metered Outdoor Nighttime Lighting)	1.80~~0.21~~%
Schedule 21	3.76~~0.45~~%
Schedule 23	1.16~~0.14~~%
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 – Continued

EBA FERC 501 Adjustments

FERC Sub 5013500

SAP 515200 – Natural Gas Consumed

Gadsby Related Portion of 515200 is transferred to FERC 547(Fuel-Other Generation)

SAP 515220 – Natural Gas Swaps

Gadsby Related portion of 515220 is transferred to FERC 547(Fuel-Other Generation)

SAP 505917– I/C Nat Gas Cons Ker. This SAP account is transferred to FERC 547(Fuel-Other Generation)

FERC 447 – Sales For Resale

FERC Sub 4471400

SAP 301406 – Short-term Firm Wholesale

Non Transalta Sales (Include)

SAP 301409 – Trading Sales Netted-Estimate (Exclude)
SAP 301410 – Trade Sales Netted (Include)
SAP 301411 – Bookout Sales Netted (Include)
SAP 301412 – Bookout Sales Netted-Estimate (Exclude)
SAP 302751 – I/C ST Firm Whls-Sie (Include)
SAP 302752 – I/C S-T Firm Wholesale Sales-Nevada Pwr (Include)
SAP 302771 – I/C Line Loss Trading Revenue-Sierra Pac (Include)
SAP 302772 – I/C Line Loss-Nevada (Include)
SAP 303028 – Line Loss W/S Trading (Include)
SAP 303100 – Transmission Loss Charge Pass-Through (Exclude)
SAP 303109 – Transmission Line Loss Rev – Subject to Refund (Include)

FERC Sub 4471300

SAP 301405 – FIRM Sales (Include)

FERC Sub 4476100

SAP 304101 – Bookouts Netted – Gain (Include)
SAP 304102 – Bookouts Netted – Estimates (Exclude)

FERC Sub 4476200

SAP 304201 – Trading Net- Gains (Include)

FERC Sub 4472000 – Sales for Resale Estimates (Exclude)

FERC Sub 4475000

SAP 301408 – Off-System Non Firm (Include)

FERC Sub 4479000 – Transmission Services - Utah FERC Customers, Wyo-Pacific Cheyenne (Exclude)

FERC Sub 4471000 – Onsystem Firm - Utah FERC Customers, Wyo-Pacific Cheyenne, Brigham City, Portland General Electric (Exclude)

(continued)

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

EBA FERC 447 Adjustments

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

FERC 555 – Purchased Power

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

FERC 555 – Purchased Power (continued)

FERC Sub 5552200,2300,2400 – REC Purchases, RPS Compliance Purchases (Exclude)
FERC Sub 5552500
SAP 505185 – Net Metering Export Credit-UT Solar (Include)
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 5552700
SAP 505195 – Purchased Power-UT Subscriber Solar
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)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **Fourth Revision of Sheet No. 94.8**
Canceling Third Revision of Sheet No. 94.8

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

FERC 547 Fuel – Other Generation

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

EBA FERC 547 Adjustments

FERC Sub 5013500

SAP 515200 – Natural Gas Consumed

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

SAP 515220 – Natural Gas Swaps

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

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

FERC 456.1 Revenues from Transmission of Electricity by Others

FERC Sub 4561100

SAP 505961 – Transmission Imbalance Penalty Revenue – Load (Exclude)
SAP 505963 – Transmission Imbalance Penalty Revenue –Pt to Pt (Exclude)
SAP (All Other) – Primary Delivery and Distribution Sub Charges, Ancillary Revenue, Use of Facility – Revenue, Transmission Resales to Other Parties, Transmission Revenue Unreserved Use Charges Transmission Revenue – Deferral Fees (Include)
SAP 302081 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)
SAP 302082 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)
SAP 302091 - I/C Anc Rev Sch 2-Reactive-Sierra Pac (Include)
SAP 302092 - I/C Anc Rev Sch 2-Reactive-Nevada Pwr (Include)
SAP 302821 - I/C Anc Rev Sch 1-Scheduling-Sierra Pac (Include)
SAP 302822 - I/C Anc Rev Sch 1-Scheduling-Nevada Pwr (Include)
SAP 302831 – I/C Other Wheeling Revenue-Sierra Pac (Include)
SAP 302832 – I/C Other Wheeling Revenue-Nevada (Include)

FERC Sub 4561600

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

FERC Sub 4561910

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

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

FERC Sub 4561930

SAP 301922 – Non-Firm Wheeling Revenue (Include)

FERC Sub 4561990

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

(continued)

ELECTRIC SERVICE SCHEDULE NO. 94 – Continued

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.

Schedule 1	1.07%
Schedule 2	1.07%
Schedule 2E	1.07%
Schedule 3	1.07%
Schedule 6	1.42%
Schedule 6A	2.16%
Schedule 6B	1.42%
Schedule 7*	0.67%
Schedule 8	1.55%
Schedule 9	1.86%
Schedule 9A	2.07%
Schedule 10	1.38%
Schedule 11*	0.67%
Schedule 12*	0.67%
Schedule 15 (Traffic and Other Signal Systems)	1.21%
Schedule 15 (Metered Outdoor Nighttime Lighting)	1.80%
Schedule 21	3.76%
Schedule 23	1.16%
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.