ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

March 16, 2020

***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 Administrator

RE: **Docket No. 20-035-01**
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
emily.wegener@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. 20-035-01

Richard Garlish
Emily L. Wegener (12275)
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
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*Attorneys for Rocky Mountain Power*

**BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO INCREASE THE DEFERRED EBA RATE THROUGH THE ENERGY BALANCING ACCOUNT MECHANISM | ) ) ) ) ) | Docket No. 20-035-01 |

**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 $36.8 million in deferred EBA Costs ("EBAC"). The $36.8 million includes the following components: (1) a surcharge of approximately $44.0 million, the difference between the Actual EBAC and the Base EBAC in current base rates for the period beginning January 1, 2019 through December 31, 2019 ("Deferral Period"); (2) a credit of approximately $2.9 million for savings related to the Retiree Medical

Obligation; (3) a credit of approximately $8.7 million related to an adjustment for sales made to a special contract customer; (4) approximately $1.6 million in costs related to the Utah situs resources; and (5) a charge of approximately $2.9 million in accrued interest.

The Company has included revised Tariff Schedule 94 to recover from customers $36.8 million. This results in an overall increase to retail customers of the Tariff Schedule 94 rate of approximately 1.0 percent.

This Application is consistent with Tariff Schedule 94, approved by the Commission on July 17, 2012, as amended by the Commission's Order on EBA Interim Rate Process, issued August 30, 2012, and as amended in Dockets Nos. 16-035-T05 and 09-035-15 by orders issued May 16, 2016, February 16, 2017, and November 14, 2019 (together, the "EBA Order").[1] The Commission's most recent order, entered November 14, 2019, approved the EBA as an ongoing program, rather than a "pilot" program, and changed the carrying charge to be consistent with the Company's other account balances as of January 1, 2020.[2]

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

[1] *In the Matter of Rocky Mountain Power for Approval of Its Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Order (Nov. 14, 2019).
[2] *Id.* at 10, citing *In the Matter of a Request for Agency Action to Review the Carrying Charges Applied to Various Rocky Mountain Power Account Balances,* Docket No. 15-035-69, Order issued February 27, 2017.

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, per the schedule in Tariff Schedule 94, on March 1, 2021. 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

Emily Wegener
Senior Attorney
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
E-mail: emily.wegener@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 a rate effective date of March 1, 2021.

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. 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 2019 through December 31, 2019, 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. David G. Webb.

8. The Deferral Period for this Application is the 12-month period beginning January 1, 2019 through December 31, 2019.

9. The request in this Application includes five components: (1) the EBA deferral amount ("EBA Deferral Amount") for a charge of approximately $44.0 million; (2) a credit of approximately $2.9 million for savings related to the Retiree Medical Obligation; (3) a credit of approximately $8.7 million related to an adjustment for sales made to a special contract customer; (4) approximately $1.6 million in costs related to the Utah situs resources; and (5) a charge of approximately $2.9 million in accrued interest.

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

11. 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 increases in purchased power and natural gas expense, partially offset by a reduction in coal fuel and wheeling expenses, among other expenses.

12. 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___(DGW-1)**, attached to Mr. Webb's direct testimony.

**Deferred EBA Cost Adjustment**

13. Pursuant to Tariff Schedule 94, the deferred EBAC adjustment is calculated monthly and recorded as a deferred expense on the Company's books. Mr. Webb's **Exhibit RMP___( DGW-1)** shows the detailed calculation of the EBA Deferral Amount. Adjusted Actual Total NPC from January 1, 2019 through December 31, 2019 were approximately $1,648 million, compared to the $1,491 million Base NPC being used in this case.

14. Utah's allocated NPC before wheeling revenues were approximately $716 million. After crediting Utah-allocated wheeling revenues of approximately $48 million, Utah actual EBAC were approximately $667 million, shown on line 3, or $27.05 per megawatt-hour ("MWh"), shown on line 5.

15. 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 2019 load produces the deferred EBAC of approximately $44.0 million, shown on line 12.

16. 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 $8.7 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 $1.6 million is shown on line 17. A charge for interest of approximately $1.2 million for the Deferral Period (January 1, 2019 through December 31, 2019) is shown on line 22. A charge for expense for interest of approximately $385 thousand (from January 2020 through March 2020) is shown on line 24. A charge for expense for interest of approximately $1.3 million (from April 2020 through February 2021) is shown on line 25. The total ending deferral amount of approximately $36.8 million is shown on line 26.

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

| Calendar Year 2019 EBA Deferral | | | Exhibit RMP___(DGW-1) Reference |
|---|---|---|---|
| Actual EBA ($/MWh) | $ | 27.05 | *Line 5* |
| Base EBA ($/MWh) | | 25.25 | *Line 10* |
| $/MWh Differential | **$** | **1.80** | |
| Utah Sales (MWh) | 24,669,334 | | *Line 4* |
| EBA Deferrable* | $ 43,978,176 | | *Line 12* |
| Incremental Non-Fuel FAS 106 Savings* | (2,947,878) | | *Line 13* |
| Special Contract Customer Adjustment* | (8,733,909) | | *Line 16* |
| Utah Situs Resource Adjustment* | 1,641,004 | | *Line 17* |
| Total Deferrable | 33,937,393 | | *Line 18* |
| Interest Accrued through December 31, 2019 | 1,212,736 | | *Line 22* |
| Interest Jan 1, 2020 through Mar 31, 2020 | 385,415 | | *Line 24* |
| Interest Apr 1, 2020 through Feb 28, 2021 | 1,284,513 | | *Line 25* |
| **Requested EBA Recovery** | **$ 36,820,057** | | *Line 26* |

* Calculated monthly

## Proposed Tariff Sheets

18. The Company's proposes 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. Robert M. Meredith.

19. The Company proposes to allocate the 2020 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.

20. 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 1.0 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 2020 EBA** |
|---|---|
| **Residential** | |
| Schedules 1, 2, 3 | 0.8% |
| **General Service** | |
| Schedule 23 | 0.9% |
| Schedule 6 | 1.0% |
| Schedule 8 | 1.1% |
| Schedule 9 | 1.4% |
| **Irrigation** | |
| | |
| Schedule 10 | 1.1% |
| **Public Street and Area Lighting Schedules** | |
| Schedules 7, 11, 12 | 0.6% |
| Schedule 15 - Metered Outdoor Lighting | 1.1% |
| Schedule 15 - Traffic Signal Systems | 0.8% |
| | |
| **Total** | 1.0% |

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission approve rates as provided in Tariff Schedule 94 to recover the costs identified in this Application, as filed, with an effective date of March 1, 2021.

DATED this 16th day of March 2020.

Respectfully submitted,

ROCKY MOUNTAIN POWER

________________________________

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## CERTIFICATE OF SERVICE

Docket No. 20-035-01

I hereby certify that on March 16, 2020, 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 |
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Adviser, Regulatory Operations

Rocky Mountain Power
Docket No. 20-035-01
Witness: David G. Webb

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of David G. Webb

March 2020

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

A. My name is David G. Webb and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

## QUALIFICATIONS

**Q. Please describe your education and professional experience.**

A. I received a Master of Accountancy degree from Southern Utah University in 1999 and a Bachelor of Science degree in Business Management from Brigham Young University in 1994. I am a Certified Public Accountant licensed in the state of Nevada. I have been employed by PacifiCorp since 2005 and have held various positions in the regulation, finance, fuels, and mining departments. I assumed my current role managing the regulatory net power cost group in 2019.

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

A. Yes. I have previously provided testimony to the public service commissions in Utah, Wyoming, and Oregon.

## PURPOSE OF TESTIMONY

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

A. My testimony presents and supports the Company's calculation of the Energy Balancing Account ("EBA") deferral for the 12-month period from January 1, 2019 through December 31, 2019 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $36.8 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, an adjustment for sales made to a special contract customer, and Utah situs resource adjustments included in the EBA for the true-up of solar facilities and the Utah Transition Program for Customer Generators;

- 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, Director, 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 $36.8 million in deferred costs, comprised of $44.0 million of EBA-related costs, a credit of $2.9 million for savings for the Retiree Medical Obligation, a credit of $8.7 million for sales made to a special contract customer, a $1.6 million adjustment for Utah situs resources, and $2.9 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:

- EBA Carrying Charge rate change from 6% annually to the rate approved by the Commission for the Company's Electric Service Schedule No. 300 in accordance with the Commission's order issued November 14, 2019 in Docket No. 09-035-15.
- An adjustment related to Electric Service Schedule No. Schedule 32 ("Schedule 32") contract costs associated with the contract approved by the Commission in Docket No. 18-035-08.

## 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___(DGW-1) presents the detailed calculation of the EBA deferral on a monthly basis.

**Table 1**

**Annual EBA Calculation**

| **<u>Calendar Year 2019 EBA Deferral</u>** | | | *Exhibit RMP (DGW-1) Reference* |
|---|---|---|---|
| Actual EBA ($/MWh) | $ | 27.05 | *Line 5* |
| Base EBA ($/MWh) | | 25.25 | *Line 10* |
| $/MWh Differential | **$** | **1.80** | |
| Utah Sales (MWh) | | 24,669,334 | *Line 4* |
| EBA Deferrable* | | $ 43,978,176 | *Line 12* |
| Incremental Non-Fuel FAS 106 Savings* | | (2,947,878) | *Line 13* |
| Special Contract Customer Adjustment* | | (8,733,909) | *Line 16* |
| Utah Situs Resource Adjustment* | | 1,641,004 | *Line 17* |
| Total Deferrable | | 33,937,393 | *Line 18* |
| Interest Accrued through December 31, 2019 | | 1,212,736 | *Line 22* |
| Interest Jan 1, 2020 through Mar 31, 2020 | | 385,415 | *Line 24* |
| Interest Apr 1, 2020 through Feb 28, 2021 | | 1,284,513 | *Line 25* |
| **Requested EBA Recovery** | | **$ 36,820,057** | *Line 26* |

* Calculated monthly

The EBA deferral of $44.0 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").

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 $1,648 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 2019, no new accounts were used in the Company's SAP accounting system to track components of NPC and wheeling revenue.

**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,
- Utah Schedule 32 contract.

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___(DGW-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, February 16, 2017, and November 14, 2019 in Docket No. 09-035-15, carrying charges accrue on the monthly EBA deferral at an annual rate of six percent through December 31, 2019.

Effective January 1, 2020 the carrying charge has been changed to the interest rate for Residential and Non-residential Deposits in Electric Service Schedule No. 300. 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 2020 EBA, the adjustment for sales made to a special contract customer is an $8.7 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. 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 $20 thousand.

**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.

**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. The EBA adjustment for the Transition Program is approximately $1.6 million.

**Q. Please describe the adjustment to the EBA for the Schedule 32 Contract.**

A. Electric Service Schedule No. 32 is a unique retail service option available to any customer who would otherwise qualify for Electric Service Schedules 6, 8, or 9 that desires to receive all or part of its electricity from a renewable energy facility. This allows the Company to meet its customers' renewable energy goals while protecting the Company's other customers from the financial impacts of another customer's preference. Currently, the only customer with a contract pursuant to Schedule 32 is with the University of Utah and was approved in Docket No. 18-035-08. The contract is a pass-through and has no impact on the EBA.

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

A. The 2020 EBA includes the non-fuel savings related to the settlement of Deer Creek Retiree Medical Obligation. In the 2020 EBA the non-fuel savings are allocated to Utah using the system overhead ("SO") allocation factor from the June 30, 2019 results of operations. At the time of this filing, the calendar year 2019 SO allocation factor was not yet available.

## 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 $1,648 million, approximately $157 million more than Base NPC for the Deferral Period. 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** | **$** | **1,491** |
| | | |
| Increase/(Decrease) to NPC: | | |
| Wholesale Sales Revenue | | 214 |
| Purchased Power Expense | | 82 |
| Coal Fuel Expense | | (145) |
| Natural Gas Expense | | 8 |
| Wheeling and Other Expense | | (4) |
| **Total Increase/(Decrease)** | | **154** |
| 2014 GRC Settlement Adjustment | | 3 |
| **Total Company NPC Difference** | **$** | **157** |
| | | |
| **Adjusted Actual NPC** | **$** | **1,648** |

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

A. The Base NPC for the 2020 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. As shown in Table 2, Actual NPC were higher than Base NPC due to a $214 million reduction in wholesale sales, an $82 million increase in purchased power expense, and an $8 million increase in natural gas expense. The items were partially offset by a

$145 million reduction in coal fuel expense, and a $4 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 $214 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 $4.71/MWh, or 12 percent lower than the average price in Base NPC. Actual wholesale market volumes were 4,798 gigawatt-hours ("GWh"), or 48 percent lower than the Base NPC.

**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 the addition of 19 new large qualifying facility contracts, and the expiration of the Hermiston purchase power agreement ("PPA") and the Georgia-Pacific Camas contract. The Hermiston PPA and the Georgia-Pacific Camas contract expirations 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 $65.4 million compared to Base NPC. Actual market purchases were 507 GWh (10 percent) higher than Base NPC and the average price of actual market purchases transactions was $18.10/MWh (59 percent) higher than Base NPC.

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

A. Actual long-term wheeling expense decreased by approximately $8.5 million when compared to Base NPC due to expired wheeling contracts. This was partially offset by an increase of $6.8 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 a coal generation volume decrease of 8,129 GWh (19 percent) compared to Base NPC. The average cost of coal generation increased only slightly from $19.77/MWh in Base NPC to $20.22/MWh in the Deferral Period, but the lower generation results in an overall decrease of approximately $145 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 increased by $8 million compared to Base NPC. The main driver of the increase is the average cost of natural gas generation decreased from $39.73/MWh in Base NPC to $23.79/MWh (40 percent) in the Deferral Period, but reduced costs were offset by an increase in natural gas generation volume of 5,030 GWh (72 percent) above Base NPC during the Deferral Period.

**Q. Please provide an update 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 were completed. Spot natural gas prices at the Sumas B.C.-U.S. border trading point traded as high as $159 per million British thermal units on days of intense demand due to cold weather and reduced natural gas supply in the first quarter of 2019.

The pipeline rupture and reduced operating capacity impacted electricity prices primarily at the Mid-Columbia power market hub, but also increased electricity prices 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, there were times of limited availability of natural gas flowing to the Sumas gas hub and limited ability to withdraw out of storage facilities at Jackson Prairie. With the inability to run Chehalis due to limited gas availability and supplies, plus the impact of uneconomical market conditions, the result contributed to higher prices at Mid-Columbia ultimately increasing net power costs.

## 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 $57.2 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___(DGW-1)
Docket No. 20-035-01
Witness: David G. Webb

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of David G. Webb

Monthly EBA Deferral

March 2019

**Utah Energy Balancing Account Mechanism**
**January 1, 2019 - December 31, 2019**
**Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor)**

| Line No. | | Reference | Jan-19 | Feb-19 | Mar-19 | Apr-19 | May-19 | Jun-19 | Jul-19 | Aug-19 | Sep-19 | Oct-19 | Nov-19 | Dec-19 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actual: Utah Allocated** | | | | | | | | | | | | | | | |
| 1 | NPC | (2.1) | $ 56,648,302 | $ 71,026,038 | $ 58,971,405 | $ 46,567,876 | $ 48,819,808 | $ 54,490,668 | $ 72,645,842 | $ 76,922,130 | $ 65,948,407 | $ 54,825,201 | $ 53,682,689 | $ 55,481,443 | $ 716,029,809 |
| 2 | Wheeling Revenue | (4.1) | (3,795,472) | (4,623,913) | (3,891,688) | (3,742,765) | (3,560,774) | (5,191,101) | (4,128,411) | (4,609,655) | (4,369,473) | (3,918,758) | (3,782,164) | (3,020,719) | (48,634,892) |
| 3 | Total | ∑ Lines 1:2 | $ 52,852,830 | $ 66,402,124 | $ 55,079,717 | $ 42,825,112 | $ 45,259,034 | $ 49,299,568 | $ 68,517,431 | $ 72,312,475 | $ 61,578,934 | $ 50,906,443 | $ 49,900,525 | $ 52,460,724 | $ 667,394,916 |
| 4 | Jurisdictional Sales | (5.2) | 2,065,623 | 1,870,047 | 1,892,762 | 1,817,505 | 1,881,761 | 2,054,454 | 2,516,288 | 2,460,994 | 2,047,013 | 2,023,258 | 1,932,103 | 2,107,526 | 24,669,334 |
| 5 | Actual Utah $/MWh | Line 3 / Line 4 | **$ 25.59** | **$ 35.51** | **$ 29.10** | **$ 23.56** | **$ 24.05** | **$ 24.00** | **$ 27.23** | **$ 29.38** | **$ 30.08** | **$ 25.16** | **$ 25.83** | **$ 24.89** | **$ 27.05** |
| **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 | $ 1.07 | $ 10.41 | $ 3.23 | $ (0.90) | $ (1.10) | $ (1.46) | $ 1.16 | $ 2.74 | $ 5.26 | $ 0.07 | $ 1.16 | $ 0.03 | $ 1.80 |
| 12 | EBA Deferrable | Line 4 * Line 11 | **$ 2,214,514** | **$ 19,475,270** | **$ 6,118,711** | **$ (1,642,492)** | **$ (2,074,636)** | **$ (3,006,842)** | **$ 2,930,228** | **$ 6,754,851** | **$ 10,763,677** | **$ 138,505** | **$ 2,248,699** | **$ 57,691** | **$ 43,978,176** |
| 13 | Incremental Non-Fuel FAS 106 Savings | (6.1) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (245,656) | (2,947,878) |
| 14 | Special Contract Customer Adjustment Subject to Deadband | (7.1) | (439,970) | (4,418,824) | (5,284,926) | 712,174 | 1,192,950 | 769,397 | (10,086) | (627) | (140,288) | (378,575) | (500,262) | (584,873) | (9,083,909) |
| 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 | (89,970) | (4,418,824) | (5,284,926) | 712,174 | 1,192,950 | 769,397 | (10,086) | (627) | (140,288) | (378,575) | (500,262) | (584,873) | (8,733,909) |
| 17 | Utah Situs Resource Adjustment | (8.1) | (56,371) | (46,252) | 77,221 | 160,865 | 278,278 | 312,557 | 207,076 | 241,818 | 238,423 | 236,310 | 54,906 | (63,828) | 1,641,004 |
| 18 | Total Incremental EBA Deferral | ∑ Lines 12:13 and Lines 16:17 | **$ 1,822,516** | **$ 14,764,538** | **$ 665,351** | **$ (1,015,109)** | **$ (849,064)** | **$ (2,170,545)** | **$ 2,881,562** | **$ 6,750,385** | **$ 10,616,156** | **$ (249,416)** | **$ 1,557,687** | **$ (836,667)** | **$ 33,937,393** |
| **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 23 | $ - | $ 1,827,072 | $ 16,637,657 | $ 17,387,859 | $ 16,457,152 | $ 15,688,251 | $ 13,590,721 | $ 16,547,440 | $ 23,397,438 | $ 34,157,122 | $ 34,077,868 | 35,809,838 | $ - |
| 21 | Incremental Deferral | Line 18 | 1,822,516 | 14,764,538 | 665,351 | (1,015,109) | (849,064) | (2,170,545) | 2,881,562 | 6,750,385 | 10,616,156 | (249,416) | 1,557,687 | (836,667) | 33,937,393 |
| 22 | Interest | Line 19 * ( Line 20 + 50% x Line 21) | 4,556 | 46,047 | 84,852 | 84,402 | 80,163 | 73,015 | 75,158 | 99,613 | 143,528 | 170,162 | 174,284 | 176,958 | 1,212,736 |
| 23 | **Ending Balance** | ∑ Lines 20:22 | **$ 1,827,072** | **$ 16,637,657** | **$ 17,387,859** | **$ 16,457,152** | **$ 15,688,251** | **$ 13,590,721** | **$ 16,547,440** | **$ 23,397,438** | **$ 34,157,122** | **$ 34,077,868** | **$ 35,809,838** | **$ 35,150,129** | **$ 35,150,129** |
| 24 | Accrued Interest through March 31, 2020 | Line 23 * (1 + 1.0437% / 12) ^ 3 - Line 23 | | | | | | | | | | | | | 385,415 |
| 25 | Accrued Interest April 1st, 2020 through February 28, 2021 | Line 23 * (1 + 1.0388% / 12) ^ 11 - Line 23 | | | | | | | | | | | | | 1,284,513 |
| 26 | **Requested EBA Recovery** | ∑ Lines 23:24 | | | | | | | | | | | | | **$ 36,820,057** |

Notes:
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
2 Line 24 - Accrued interest through February 28, 2021 represents a change from May 1, 2020 due to the elimination of interim rates and the new date that the 2019 EBA is recovered.
3 Line 24 and 25 - Interest rate changed from 6% annually to Electric Service Schedule No. 300 due to Docket No. 09-035-15/Order Issued November 14, 2019.

Rocky Mountain Power
Docket No. 20-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Direct Testimony of Robert M. Meredith

March 2020

**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 Director, Pricing and Cost of Service.

## QUALIFICATIONS

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

A. I have a Bachelor of Science degree in Business Administration and a minor in Economics from Oregon State University. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 15 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over nine years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In June 2019, I was promoted to my current position.

**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. David G. Webb for the 12-months ended December 31, 2019 ("2020 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 $19.5 million, or 1.0 percent. This net change is the difference between the current collection level of $17.3 million and the new proposed collection level of $36.8 million for the 2020 EBA. Exhibit RMP___(RMM-1), page 1, shows the net impact by rate schedule.

## PROPOSED EBA RATE SPREAD

**Q. What is the 2020 EBA deferral amount in this case?**

A. The total 2020 EBA deferral is $36.8 million, as shown in Table 1 of Mr. Webb's testimony. The Company proposes to recover this amount over one year with rates effective March 1, 2021.

**Q. How does the Company propose to allocate the 2020 EBA deferral balance across customer classes?**

A. The Company proposes to spread the 2020 EBA deferral across customer rate schedules consistent with the NPC Allocators agreed to by the parties and approved by the Commission in the 2014 general rate case, Docket No. 13-035-184 ("2014 GRC"). The allocators and allocations by rate schedule are shown on page 2 in Exhibit RMP___(RMM-1).

**Q. How does the Company propose to allocate the 2020 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 2020 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 2020 EBA revenue allocation for Contract Customer 1 is based on the overall 2020 EBA percentage to tariff customers in Utah.

**Q. How does the Company propose to collect the 2020 EBA deferral after these adjustments to the NPC Allocators?**

A. The results of the 2020 EBA deferral spread based on the NPC Allocator are then proportionally adjusted for all customer classes to collect a total target amount of $36.8 million.

**Q. What present revenues and billing determinants is the Company proposing to use to allocate the 2020 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.

**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 an adjustment to remove revenue from Subscriber Solar Program participants, 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. 20-035-01
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 2020

**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 | $5,032 | $689,537 | $684,505 | $10,693 | $695,198 | $0 | 0.0% | $5,661 | 0.8% |
| 2 | Residential-Optional TOD | 2 | 447 | 3,186 | $351 | $3 | $354 | $351 | $5 | $357 | $0 | 0.0% | $3 | 0.8% |
| 3 | AGA/Revenue Credit | -- | | | $33 | | $33 | $33 | | $33 | $0 | 0.0% | $0 | 0.0% |
| 4 | **Total Residential** | | 740,636 | 6,203,852 | $684,889 | $5,035 | $689,924 | $684,889 | $10,698 | $695,588 | $0 | 0.0% | $5,664 | 0.8% |
| | **Commercial & Industrial & OSPA** | | | | | | | | | | | | | |
| 5 | General Service-Distribution | 6 | 13,072 | 5,783,806 | $494,681 | $4,449 | $499,130 | $494,681 | $9,443 | $504,125 | $0 | 0.0% | $4,994 | 1.0% |
| 6 | General Service-Distribution-Energy TOD | 6A | 2,276 | 292,031 | $34,227 | $308 | $34,535 | $34,227 | $654 | $34,881 | $0 | 0.0% | $346 | 1.0% |
| 7 | General Service-Distribution-Demand TOD | 6B | 37 | 3,907 | $346 | $3 | $349 | $346 | $6 | $352 | $0 | 0.0% | $3 | 1.0% |
| 8 | *Subtotal Schedule 6* | | 15,385 | 6,079,745 | $529,255 | $4,760 | $534,014 | $529,255 | $10,104 | $539,358 | $0 | 0.0% | $5,344 | 1.0% |
| 9 | General Service-Distribution > 1,000 kW | 8 | 274 | 2,187,047 | $167,313 | $1,675 | $168,988 | $167,313 | $3,568 | $170,882 | $0 | 0.0% | $1,893 | 1.1% |
| 10 | General Service-High Voltage | 9 | 149 | 5,027,436 | $284,876 | $3,674 | $288,550 | $284,876 | $7,797 | $292,674 | $0 | 0.0% | $4,123 | 1.4% |
| 11 | General Service-High Voltage-Energy TOD | 9A | 9 | 42,591 | $3,293 | $42 | $3,335 | $3,293 | $90 | $3,382 | $0 | 0.0% | $47 | 1.4% |
| 12 | *Subtotal Schedule 9* | | 158 | 5,070,026 | $288,169 | $3,716 | $291,885 | $288,169 | $7,887 | $296,056 | $0 | 0.0% | $4,171 | 1.4% |
| 13 | Irrigation | 10 | 2,784 | 173,133 | $13,210 | $131 | $13,341 | $13,210 | $280 | $13,490 | $0 | 0.0% | $149 | 1.1% |
| 14 | Irrigation-Time of Day | 10TOD | 261 | 16,757 | $1,286 | $13 | $1,298 | $1,286 | $27 | $1,313 | $0 | 0.0% | $15 | 1.1% |
| 15 | *Subtotal Irrigation* | | 3,045 | 189,890 | $14,496 | $144 | $14,640 | $14,496 | $308 | $14,803 | $0 | 0.0% | $164 | 1.1% |
| 16 | Electric Furnace | 21 | 5 | 4,049 | $476 | $6 | $482 | $476 | $13 | $489 | $0 | 0.0% | $7 | 1.4% |
| 17 | General Service-Distribution-Small | 23 | 82,668 | 1,390,888 | $139,103 | $1,109 | $140,212 | $139,103 | $2,360 | $141,463 | $0 | 0.0% | $1,251 | 0.9% |
| 18 | Back-up, Maintenance, & Supplementary | 31 | 4 | 56,282 | $4,576 | $44 | $4,620 | $4,576 | $94 | $4,669 | $0 | 0.0% | $50 | 1.1% |
| 19 | Contract 1 | -- | 1 | 535,721 | $27,959 | $249 | $28,208 | $27,959 | $532 | $28,491 | $0 | 0.0% | $283 | 1.0% |
| 20 | Contract 2 | -- | 1 | 795,799 | $35,063 | $512 | $35,575 | $35,063 | $1,090 | $36,153 | $0 | 0.0% | $579 | 1.6% |
| 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 | $12,215 | $1,251,587 | $1,239,372 | $25,956 | $1,265,328 | $0 | 0.0% | $13,741 | 1.1% |
| | **Public Street Lighting** | | | | | | | | | | | | | |
| 24 | Security Area Lighting | 7 | 8,046 | 12,441 | $2,999 | $15 | $3,014 | $2,999 | $32 | $3,031 | $0 | 0.0% | $17 | 0.6% |
| 25 | Street Lighting - Company Owned | 11 | 809 | 16,496 | $4,979 | $25 | $5,004 | $4,979 | $53 | $5,032 | $0 | 0.0% | $28 | 0.6% |
| 26 | Street Lighting - Customer Owned | 12 | 839 | 56,517 | $4,145 | $21 | $4,166 | $4,145 | $44 | $4,189 | $0 | 0.0% | $23 | 0.6% |
| 27 | Metered Outdoor Lighting | 15 | 2,466 | 6,178 | $1,235 | $13 | $1,247 | $1,235 | $27 | $1,261 | $0 | 0.0% | $14 | 1.1% |
| 28 | Traffic Signal Systems | 15 | 515 | 17,536 | $682 | $5 | $687 | $682 | $10 | $692 | $0 | 0.0% | $5 | 0.8% |
| 29 | *Subtotal Public Street Lighting* | | 12,675 | 109,168 | $14,040 | $78 | $14,118 | $14,040 | $165 | $14,205 | $0 | 0.0% | $87 | 0.6% |
| 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 | $78 | $14,123 | $14,045 | $165 | $14,210 | $0 | 0.0% | $87 | 0.6% |
| 33 | **Total Sales to Ultimate Customers** | | 854,859 | 23,244,285 | $1,938,306 | $17,327 | $1,955,634 | $1,938,306 | $36,819 | $1,975,126 | $0 | 0.0% | $19,492 | 1.0% |

**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 | | $10,690 | 1.6% |
| 2 | Residential-Optional TOD | 2 | $351 | | $5 | 1.6% |
| 3 | AGA/Revenue Credit | -- | $33 | | | |
| 4 | **Total Residential** | | $684,889 | $170,321 | $10,695 | 1.6% |
| | **Commercial & Industrial & OSPA** | | | | | |
| 5 | General Service-Distribution | 6 | $494,681 | | $9,451 | 1.9% |
| 6 | General Service-Distribution-Energy TOD | 6A | $34,227 | | $654 | 1.9% |
| 7 | General Service-Distribution-Demand TOD | 6B | $346 | | $7 | 1.9% |
| 8 | *Subtotal Schedule 6* | | $529,255 | $161,024 | $10,111 | 1.9% |
| 9 | General Service-Distribution > 1,000 kW | 8 | $167,313 | $56,651 | $3,557 | 2.1% |
| 10 | General Service-High Voltage | 9 | $284,876 | | $7,771 | 2.7% |
| 11 | General Service-High Voltage-Energy TOD | 9A | $3,293 | | $90 | 2.7% |
| 12 | *Subtotal Schedule 9* | | $288,169 | $125,184 | $7,861 | 2.7% |
| 13 | Irrigation | 10 | $13,210 | | $280 | 2.1% |
| 14 | Irrigation-Time of Day | 10TOD | $1,286 | | $27 | 2.1% |
| 15 | *Subtotal Irrigation* | | $14,496 | $4,897 | $308 | 2.1% |
| 16 | Electric Furnace | 21 | $476 | | $13 | 2.7% |
| 17 | General Service-Distribution-Small | 23 | $139,103 | $37,646 | $2,364 | 1.7% |
| 18 | Back-up, Maintenance, & Supplementary | 31 | $4,576 | | $125 | 2.7% |
| 19 | Contract 1 | -- | $27,959 | $13,217 | $531 | 1.9% |
| 20 | Contract 2 | -- | $35,063 | $17,354 | $1,090 | 3.1% |
| 21 | Contract 3 | -- | $30,035 | | $0 | 0.0% |
| 22 | AGA/Revenue Credit | -- | $2,928 | | | |
| 23 | **Total Commercial & Industrial & OSPA** | | $1,239,372 | $415,974 | $25,959 | 2.1% |
| | **Public Street Lighting** | | | | | |
| 24 | Security Area Lighting | 7 | $2,999 | $508 | $32 | 1.1% |
| 25 | Street Lighting - Company Owned | 11 | $4,979 | $844 | $53 | 1.1% |
| 26 | Street Lighting - Customer Owned | 12 | $4,145 | $702 | $44 | 1.1% |
| 27 | Metered Outdoor Lighting | 15 | $1,235 | $425 | $27 | 2.2% |
| 28 | Traffic Signal Systems | 15 | $682 | $159 | $10 | 1.5% |
| 29 | *Subtotal Public Street Lighting* | | $14,040 | $2,638 | $166 | 1.2% |
| 30 | Security Area Lighting-Contracts (PTL) | -- | $1 | $0 | | |
| 31 | AGA/Revenue Credit | -- | $5 | $0 | | |
| 32 | **Total Public Street Lighting** | | $14,045 | $2,638 | $166 | 1.2% |
| 33 | **Total Sales to Ultimate Customers** | | $1,938,306 | $588,932 | $36,820 | 1.9% |

| | | |
|---|---|---|
| Target EBA Rev | $36,820 | |
| Avg % | 1.9% | |
| Adj | 99.62% | 0.0 |

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

Rocky Mountain Power
Exhibit RMP___(RMM-2)
Docket No. 20-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Robert M. Meredith

Billing Determinants

March 2020

**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 | 0.80% | $899,587 | 1.70% | $1,911,622 |
| Next 600 kWh (May-Sept) | 1,040,456,011 | 11.5429 ¢ | $120,098,797 | ($377,404) | $119,721,393 | 0.80% | $957,771 | 1.70% | $2,035,264 |
| All add'l kWh (May-Sept) | 358,873,906 | 14.4508 ¢ | $51,860,150 | ($162,968) | $51,697,182 | 0.80% | $413,577 | 1.70% | $878,852 |
| All kWh (Oct-Apr) | | | | | | | | | |
| *First 400 kWh (Oct-Apr)* | 1,613,094,234 | 8.8498 ¢ | *$142,755,614* | *($448,602)* | *$142,307,012* | 0.80% | *$1,138,456* | 1.70% | *$2,419,219* |
| *All add'l kWh (Oct-Apr)* | 1,704,644,903 | 10.7072 ¢ | *$182,519,739* | *($573,560)* | *$181,946,179* | 0.80% | *$1,455,569* | 1.70% | *$3,093,085* |
| 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 | | $4,864,961 | | $10,338,042 |
| **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 | 0.80% | $33,555 | 1.70% | $71,305 |
| Next 600 kWh (May-Sept) | 31,907,309 | 11.5429 ¢ | $3,683,029 | ($3,084) | $3,679,945 | 0.80% | $29,440 | 1.70% | $62,559 |
| All add'l kWh (May-Sept) | 10,205,740 | 14.4508 ¢ | $1,474,811 | ($1,235) | $1,473,576 | 0.80% | $11,789 | 1.70% | $25,051 |
| All kWh (Oct-Apr) | | | | | | | | | |
| *First 400 kWh (Oct-Apr)* | 64,598,419 | 8.8498 ¢ | *$5,716,831* | *($4,787)* | *$5,712,044* | 0.80% | *$45,696* | 1.70% | *$97,105* |
| *All add'l kWh (Oct-Apr)* | 54,308,077 | 10.7072 ¢ | *$5,814,874* | *($4,870)* | *$5,810,004* | 0.80% | *$46,480* | 1.70% | *$98,770* |
| 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 | | $166,960 | | $354,789 |
| **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 | 0.80% | $478 | 1.70% | $1,016 |
| Next 600 kWh (May-Sept) | 474,415 | 11.5429 ¢ | $54,761 | $0 | $54,761 | 0.80% | $438 | 1.70% | $931 |
| All add'l kWh (May-Sept) | 185,128 | 14.4508 ¢ | $26,752 | $0 | $26,752 | 0.80% | $214 | 1.70% | $455 |
| All kWh (Oct-Apr) | | | | | | | | | |
| *First 400 kWh (Oct-Apr)* | 912,816 | 8.8498 ¢ | *$80,782* | *$0* | *$80,782* | 0.80% | *$646* | 1.70% | *$1,373* |
| *All add'l kWh (Oct-Apr)* | 937,823 | 10.7072 ¢ | *$100,415* | *$0* | *$100,415* | 0.80% | *$803* | 1.70% | *$1,707* |
| 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 | | $2,580 | | $5,482 |
| **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 | 1.06% | $1,172,934 | 2.25% | $2,489,718 |
| *All kW (Oct - Apr)* | *9,009,450* | *$10.91* | $98,293,100 | $0 | $98,293,100 | 1.06% | $1,041,907 | 2.25% | $2,211,595 |
| All kWh | 5,783,806,261 | | | | | | | | |
| kWh (May - Sept) | 2,573,577,152 | 3.8127 ¢ | $98,122,776 | ($84,550) | $98,038,226 | 1.06% | $1,039,205 | 2.25% | $2,205,860 |
| kWh (Oct - Apr) | 3,210,229,109 | 3.5143 ¢ | $112,817,082 | ($97,212) | $112,719,870 | 1.06% | $1,194,831 | 2.25% | $2,536,197 |
| Seasonal Service | 0 | $648.00 | $0 | | $0 | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Unbilled | | 0 | | $0 | | $0 | | | | |
| Total | | 5,783,806,261 | | $494,681,466 | ($181,762) | $494,499,704 | | $4,448,877 | | $9,443,370 |
| **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 | 1.06% | $965 | 2.25% | $2,047 |
| *All On-peak kW (Oct - Apr)* | | *4,264* | *$10.91* | $46,520 | $0 | $46,520 | 1.06% | $493 | 2.25% | $1,047 |
| All kWh | | 3,907,497 | | | | | | | | |
| kWh (May-Sept) | | 1,628,124 | 3.8127 ¢ | $62,075 | $0 | $62,075 | 1.06% | $658 | 2.25% | $1,397 |
| kWh (Oct-Apr) | | 2,279,373 | 3.5143 ¢ | $80,104 | $0 | $80,104 | 1.06% | $849 | 2.25% | $1,802 |
| Seasonal Service | | 0 | $648.00 | $0 | | $0 | | | | |
| Unbilled | | 0 | | $0 | | $0 | | | | |
| Total | | 3,907,497 | | $345,718 | $0 | $345,718 | | $2,965 | | $6,293 |
| **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 | 1.61% | $108,885 | 3.42% | $231,295 |
| Off-Peak kWh (May - Sept) | | 59,556,790 | 3.5908 ¢ | $2,138,565 | ($190,521) | $1,948,044 | 1.61% | $31,364 | 3.42% | $66,623 |
| On-Peak kWh (Oct - Apr) | | 90,625,426 | 9.9693 ¢ | $9,034,721 | ($804,889) | $8,229,832 | 1.61% | $132,500 | 3.42% | $281,460 |
| Off-Peak kWh (Oct - Apr) | | 79,597,650 | 3.0060 ¢ | $2,392,705 | ($213,164) | $2,179,541 | 1.61% | $35,091 | 3.42% | $74,540 |
| Unbilled | | 0 | | $0 | | $0 | | | | |
| Total | | 292,031,100 | | $34,227,404 | ($1,870,007) | $32,357,397 | | $307,839 | | $653,919 |
| **Schedule No. 7 - Security Area Lighting - Composite** | | | | | | | | | | |
| *MERCURY VAPOR LAMPS* | | | | | | | | | | |
| 4,000 Lumen Energy Only | 29 | 24 | $5.68 | $136 | $0 | $136 | 0.50% | $1 | 1.06% | $1 |
| 7,000 Lumen | 1 | 45,001 | $16.38 | $737,116 | $0 | $737,116 | 0.50% | $3,686 | 1.06% | $7,813 |
| 7,000 Lumen Energy Only | 28 | 0 | $8.05 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 20,000 Lumen | 2 | 10,830 | $26.78 | $290,027 | $0 | $290,027 | 0.50% | $1,450 | 1.06% | $3,074 |
| *SODIUM VAPOR LAMPS* | | | | | | | | | | |
| 5,600 Lumen New Pole | 3 | 3,563 | $14.60 | $52,020 | $0 | $52,020 | 0.50% | $260 | 1.06% | $551 |
| 5,600 Lumen No New Pole | 4 | 1,746 | $12.23 | $21,354 | $0 | $21,354 | 0.50% | $107 | 1.06% | $226 |
| 9,500 Lumen New Pole | 5 | 23,403 | $15.47 | $362,044 | $0 | $362,044 | 0.50% | $1,810 | 1.06% | $3,838 |
| 9,500 Lumen No New Pole | 6 | 23,123 | $13.31 | $307,767 | $0 | $307,767 | 0.50% | $1,539 | 1.06% | $3,262 |
| 16,000 Lumen New Pole | 7 | 2,646 | $19.46 | $51,491 | $0 | $51,491 | 0.50% | $257 | 1.06% | $546 |
| 16,000 Lumen No New Pole | 8 | 2,564 | $17.13 | $43,921 | $0 | $43,921 | 0.50% | $220 | 1.06% | $466 |
| 22,000 Lumen | 9 | 114 | $21.07 | $2,402 | $0 | $2,402 | 0.50% | $12 | 1.06% | $25 |
| 27,500 Lumen New Pole | 10 | 3,134 | $23.51 | $73,680 | $0 | $73,680 | 0.50% | $368 | 1.06% | $781 |
| 27,500 Lumen No New Pole | 11 | 4,178 | $21.23 | $88,699 | $0 | $88,699 | 0.50% | $443 | 1.06% | $940 |
| 50,000 Lumen New Pole | 12 | 1,248 | $28.30 | $35,318 | $0 | $35,318 | 0.50% | $177 | 1.06% | $374 |
| 50,000 Lumen No New Pole | 13 | 2,456 | $25.99 | $63,831 | $0 | $63,831 | 0.50% | $319 | 1.06% | $677 |
| *SODIUM VAPOR FLOOD LAMPS* | | | | | | | | | | |
| 16,000 Lumen New Pole | 14 | 4,670 | $19.46 | $90,878 | $0 | $90,878 | 0.50% | $454 | 1.06% | $963 |
| 16,000 Lumen No New Pole | 15 | 4,976 | $17.13 | $85,239 | $0 | $85,239 | 0.50% | $426 | 1.06% | $904 |
| 27,500 Lumen New Pole | 16 | 1,102 | $23.51 | $25,908 | $0 | $25,908 | 0.50% | $130 | 1.06% | $275 |
| 27,500 Lumen No New Pole | 17 | 1,570 | $21.23 | $33,331 | $0 | $33,331 | 0.50% | $167 | 1.06% | $353 |
| 50,000 Lumen New Pole | 18 | 9,734 | $28.30 | $275,472 | $0 | $275,472 | 0.50% | $1,377 | 1.06% | $2,920 |
| 50,000 Lumen No New Pole | 19 | 11,772 | $25.99 | $305,954 | $0 | $305,954 | 0.50% | $1,530 | 1.06% | $3,243 |
| *METAL HALIDE LAMPS* | | | | | | | | | | |
| 12,000 Lumen New Pole | 20 | 0 | $29.40 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 12,000 Lumen No New Pole | 21 | 265 | $21.79 | $5,774 | $0 | $5,774 | 0.50% | $29 | 1.06% | $61 |
| 19,500 Lumen New Pole | 22 | 110 | $34.34 | $3,777 | $0 | $3,777 | 0.50% | $19 | 1.06% | $40 |
| 19,500 Lumen No New Pole | 23 | 97 | $27.43 | $2,661 | $0 | $2,661 | 0.50% | $13 | 1.06% | $28 |
| 32,000 Lumen New Pole | 24 | 469 | $36.69 | $17,208 | $0 | $17,208 | 0.50% | $86 | 1.06% | $182 |
| 32,000 Lumen No New Pole | 25 | 630 | $29.72 | $18,724 | $0 | $18,724 | 0.50% | $94 | 1.06% | $198 |
| 107,000 Lumen New Pole | 26 | 24 | $57.58 | $1,382 | $0 | $1,382 | 0.50% | $7 | 1.06% | $15 |
| 107,000 Lumen No New Pole | 27 | 60 | $49.10 | $2,946 | $0 | $2,946 | 0.50% | $15 | 1.06% | $31 |
| Subtotal | | 159,509 | | $2,999,060 | $0 | $2,999,060 | | $14,995 | | $31,790 |
| kWh Included | | 12,440,931 | | | | | | | | |
| Unbilled | | 0 | | $0 | | $0 | | | | |
| Customers | | 8,046 | | | | | | | | |
| Total (kWh) | | 12,440,931 | | $2,999,060 | $0 | $2,999,060 | | $14,995 | | $31,790 |
| **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 | 1.15% | $375,384 | 2.45% | $799,730 |
| On-Peak kW (Oct - Apr) | | 2,761,958 | $11.19 | $30,906,310 | $0 | $30,906,310 | 1.15% | $355,423 | 2.45% | $757,205 |
| 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 | 1.15% | $150,972 | 2.45% | $321,636 |
| On-Peak kWh (Oct - Apr) | | 625,992,212 | 3.9511 ¢ | $24,733,578 | $0 | $24,733,578 | 1.15% | $284,436 | 2.45% | $605,973 |
| Off-Peak kWh | | 1,300,960,579 | 3.4002 ¢ | $44,235,262 | $0 | $44,235,262 | 1.15% | $508,706 | 2.45% | $1,083,764 |
| Unbilled | | 0 | | $0 | | $0 | | | | |
| Total | | 2,187,047,326 | | $167,313,409 | $0 | $167,313,409 | | $1,674,920 | | $3,568,308 |
| **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 | 1.39% | $720,921 | 2.95% | $1,530,013 |
| On-Peak kW (Oct - Apr) | 5,150,021 | $9.47 | $48,770,699 | $0 | $48,770,699 | 1.39% | $677,913 | 2.95% | $1,438,736 |
| On-Peak kWh (May-Sept) | 507,349,132 | 4.6531 ¢ | $23,607,462 | $0 | $23,607,462 | 1.39% | $328,144 | 2.95% | $696,420 |
| On-Peak kWh (Oct-Apr) | 1,382,941,034 | 3.4989 ¢ | $48,387,724 | $0 | $48,387,724 | 1.39% | $672,589 | 2.95% | $1,427,438 |
| Off-Peak kWh | 3,137,145,375 | 2.9225 ¢ | $91,683,074 | $0 | $91,683,074 | 1.39% | $1,274,395 | 2.95% | $2,704,651 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Total | 5,027,435,541 | | $284,876,452 | $0 | $284,876,452 | | $3,673,962 | | $7,797,257 |
| **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 | 1.54% | $31,538 | 3.27% | $66,968 |
| Off-Peak kWh | 18,785,533 | 3.6981 ¢ | $694,708 | $0 | $694,708 | 1.54% | $10,699 | 3.27% | $22,717 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Total | 42,590,781 | | $3,292,584 | $0 | $3,292,584 | | $42,237 | | $89,685 |
| **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 | 1.02% | $24,197 | 2.18% | $51,715 |
| 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 | 1.02% | $52,942 | 2.18% | $113,152 |
| All add'l kWh | 51,830,436 | 5.3936 ¢ | $2,795,526 | $0 | $2,795,526 | 1.02% | $28,514 | 2.18% | $60,942 |
| Total On Season | 122,960,614 | | $10,619,796 | $0 | $10,619,796 | | $105,654 | | $225,809 |
| 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 | 1.02% | $25,579 | 2.18% | $54,670 |
| Total Post Season | 50,172,778 | | $2,590,190 | $0 | $2,590,190 | | $25,579 | | $54,670 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| TOTAL RATE 10 | 173,133,392 | | $13,209,986 | $0 | $13,209,986 | | $131,233 | | $280,478 |
| **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 | 1.02% | $2,807 | 2.18% | $5,999 |
| Voltage Discount kW | 1,037 | ($2.05) | ($2,126) | | ($2,126) | | | | |
| On-Peak kWh | 2,262,299 | 14.4164 ¢ | $326,142 | $0 | $326,142 | 1.02% | $3,327 | 2.18% | $7,110 |
| Off-Peak kWh | 8,574,215 | 4.1542 ¢ | $356,190 | $0 | $356,190 | 1.02% | $3,633 | 2.18% | $7,765 |
| Total On Season | 10,836,514 | | $981,737 | $0 | $981,737 | | $9,767 | | $20,874 |
| Post Season | | | | | | | | | |
| Customer Charge | 570 | $14.00 | $7,980 | | $7,980 | | | | |
| kWh | 5,920,094 | 4.9983 ¢ | $295,904 | $0 | $295,904 | 1.02% | $3,018 | 2.18% | $6,451 |
| Total Post Season | 5,920,094 | | $303,884 | $0 | $303,884 | | $3,018 | | $6,451 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| TOTAL RATE 10-TOD | 16,756,608 | | $1,285,621 | $0 | $1,285,621 | | $12,785 | | $27,324 |
| **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 | 0.50% | $2,051 | 1.06% | $4,347 |
| 9,500 Lumen - Functional | 218,738 | $12.78 | $2,795,472 | $0 | $2,795,472 | 0.50% | $13,977 | 1.06% | $29,632 |
| 9,500 Lumen - Functional @ 90% | 132 | $11.50 | $1,518 | $0 | $1,518 | 0.50% | $8 | 1.06% | $16 |
| 9,500 Lumen - S1 | 409 | $46.54 | $19,035 | $0 | $19,035 | 0.50% | $95 | 1.06% | $202 |
| 9,500 Lumen - S2 | 60 | $38.05 | $2,283 | $0 | $2,283 | 0.50% | $11 | 1.06% | $24 |
| 16,000 Lumen - Functional | 21,158 | $16.94 | $358,417 | $0 | $358,417 | 0.50% | $1,792 | 1.06% | $3,799 |
| 16,000 Lumen - Functional @ 90% | 96 | $15.25 | $1,464 | $0 | $1,464 | 0.50% | $7 | 1.06% | $16 |
| 16,000 Lumen - S1 | 2,421 | $47.83 | $115,796 | $0 | $115,796 | 0.50% | $579 | 1.06% | $1,227 |
| 16,000 Lumen - S2 | 886 | $39.34 | $34,855 | $0 | $34,855 | 0.50% | $174 | 1.06% | $369 |
| 27,500 Lumen - Functional | 26,178 | $21.14 | $553,403 | $0 | $553,403 | 0.50% | $2,767 | 1.06% | $5,866 |
| 27,500 Lumen - Functional @ 90% | 12 | $19.03 | $228 | $0 | $228 | 0.50% | $1 | 1.06% | $2 |
| 27,500 Lumen - S1 | 1,253 | $51.48 | $64,504 | $0 | $64,504 | 0.50% | $323 | 1.06% | $684 |
| 27,500 Lumen - S2 | 0 | $43.01 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 50,000 Lumen - Functional | 11,406 | $26.02 | $296,784 | $0 | $296,784 | 0.50% | $1,484 | 1.06% | $3,146 |
| 125,000 Lumen | 0 | $51.54 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| *Metal Halide Lamps (MH)* | | | | | | | | | |
| 9,000 Lumen - S1 | 36 | $48.74 | $1,755 | $0 | $1,755 | 0.50% | $9 | 1.06% | $19 |
| 9,000 Lumen - S2 | 602 | $40.27 | $24,243 | $0 | $24,243 | 0.50% | $121 | 1.06% | $257 |
| 12,000 Lumen - Functional | 127 | $20.13 | $2,557 | $0 | $2,557 | 0.50% | $13 | 1.06% | $27 |
| 12,000 Lumen - S1 | 0 | $50.65 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 12,000 Lumen - S2 | 1,598 | $42.17 | $67,388 | $0 | $67,388 | 0.50% | $337 | 1.06% | $714 |
| 19,500 Lumen - Functional | 386 | $22.13 | $8,542 | $0 | $8,542 | 0.50% | $43 | 1.06% | $91 |
| 19,500 Lumen - S1 | 41 | $53.69 | $2,201 | $0 | $2,201 | 0.50% | $11 | 1.06% | $23 |
| 19,500 Lumen - S2 | 365 | $45.20 | $16,498 | $0 | $16,498 | 0.50% | $82 | 1.06% | $175 |
| 32,000 Lumen - Functional | 61 | $25.78 | $1,573 | $0 | $1,573 | 0.50% | $8 | 1.06% | $17 |
| 32,000 Lumen - S1 | 0 | $55.33 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 32,000 Lumen - S2 | 0 | $46.86 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| *Mercury Vapor Lamps (No New Service) (MV)* | | | | | | | | | |
| 4,000 Lumen | 3,279 | $11.09 | $36,364 | $0 | $36,364 | 0.50% | $182 | 1.06% | $385 |
| 7,000 Lumen | 9,152 | $13.83 | $126,572 | $0 | $126,572 | 0.50% | $633 | 1.06% | $1,342 |
| 10,000 Lumen | 186 | $19.40 | $3,608 | $0 | $3,608 | 0.50% | $18 | 1.06% | $38 |
| 10,000 Lumen @ 90% | 0 | $17.46 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 20,000 Lumen | 996 | $24.43 | $24,332 | $0 | $24,332 | 0.50% | $122 | 1.06% | $258 |
| *Incandescent Lamps (No New Service) (INC)* | | | | | | | | | |
| 500 Lumen | 0 | $11.99 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 600 Lumen | 145 | $4.24 | $615 | $0 | $615 | 0.50% | $3 | 1.06% | $7 |
| 2,500 Lumen | 32 | $17.11 | $548 | $0 | $548 | 0.50% | $3 | 1.06% | $6 |
| 4,000 Lumen | 162 | $20.43 | $3,310 | $0 | $3,310 | 0.50% | $17 | 1.06% | $35 |
| 6,000 Lumen | 161 | $23.82 | $3,835 | $0 | $3,835 | 0.50% | $19 | 1.06% | $41 |
| 10,000 Lumen | 24 | $31.47 | $755 | $0 | $755 | 0.50% | $4 | 1.06% | $8 |
| *Fluorescent Lamps (No New Service) (FLOUR)* | | | | | | | | | |
| 21,000 Lumen | 12 | $27.85 | $334 | $0 | $334 | 0.50% | $2 | 1.06% | $4 |
| *Special Service (No New Service)* | | | | | | | | | |
| 50,000 Lumen - Flood | 12 | $39.04 | $468 | $0 | $468 | 0.50% | $2 | 1.06% | $5 |
| Subtotal | 334,883 | | $4,979,390 | $0 | $4,979,390 | | $24,897 | | $52,782 |
| kWh Included | 16,496,197 | | | | | | | | |
| Customers | 809 | | | | | | | | |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Total | 16,496,197 | | $4,979,390 | $0 | $4,979,390 | | $24,897 | | $52,782 |
| **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 | 0.50% | $946 | 1.06% | $2,006 |
| 9,500 Lumen | 159,006 | $2.50 | $397,515 | $0 | $397,515 | 0.50% | $1,988 | 1.06% | $4,214 |
| 16,000 Lumen | 134,332 | $3.66 | $491,655 | $0 | $491,655 | 0.50% | $2,458 | 1.06% | $5,212 |
| 27,500 Lumen | 48,293 | $6.52 | $314,870 | $0 | $314,870 | 0.50% | $1,574 | 1.06% | $3,338 |
| 50,000 Lumen | 65,553 | $10.02 | $656,841 | $0 | $656,841 | 0.50% | $3,284 | 1.06% | $6,963 |
| *Metal Halide Lamps* | | | | | | | | | |
| 9,000 Lumen | 6,583 | $2.55 | $16,787 | $0 | $16,787 | 0.50% | $84 | 1.06% | $178 |
| 12,000 Lumen | 18,818 | $4.46 | $83,928 | $0 | $83,928 | 0.50% | $420 | 1.06% | $890 |
| 19,500 Lumen | 28,281 | $6.17 | $174,494 | $0 | $174,494 | 0.50% | $872 | 1.06% | $1,850 |
| 32,000 Lumen | 27,914 | $9.77 | $272,720 | $0 | $272,720 | 0.50% | $1,364 | 1.06% | $2,891 |
| *Non-listed Luminaries kWh* | 10,059,553 | 6.5279 ¢ | $656,678 | $0 | $656,678 | 0.50% | $3,283 | 1.06% | $6,961 |
| *Subtotal kWh* | 49,653,570 | | $3,254,780 | $0 | $3,254,780 | | $16,274 | | $34,501 |
| *Unbilled* | | | | | | | | | |
| *Total* | 49,653,570 | | $3,254,780 | $0 | $3,254,780 | | $16,274 | | $34,501 |
| *Customer* | 519 | | | | | | | | |
| **2a - Partial Maintenance (No New Service)** | | | | | | | | | |
| *Incandescent Lamps* | | | | | | | | | |
| 2,500 Lumen or Less | 76 | $8.96 | $681 | $0 | $681 | 0.50% | $3 | 1.06% | $7 |
| 4,000 Lumen | 91 | $12.19 | $1,109 | $0 | $1,109 | 0.50% | $6 | 1.06% | $12 |
| *Mercury Vapor Lamps* | | | | | | | | | |
| 4,000 Lumen | 47 | $4.64 | $218 | $0 | $218 | 0.50% | $1 | 1.06% | $2 |
| 7,000 Lumen | 546 | $7.00 | $3,822 | $0 | $3,822 | 0.50% | $19 | 1.06% | $41 |
| 20,000 Lumen | 140 | $13.33 | $1,866 | $0 | $1,866 | 0.50% | $9 | 1.06% | $20 |
| 54,000 Lumen | 0 | $28.38 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| *High Pressure Sodium Vapor Lamps* | | | | | | | | | |
| 5,600 Lumen | 34,609 | $4.08 | $141,205 | $0 | $141,205 | 0.50% | $706 | 1.06% | $1,497 |
| 9,500 Lumen | 15,632 | $5.37 | $83,944 | $0 | $83,944 | 0.50% | $420 | 1.06% | $890 |
| 9,500 Lumen - Decorative | 8,817 | $6.96 | $61,366 | $0 | $61,366 | 0.50% | $307 | 1.06% | $650 |
| 16,000 Lumen | 2,548 | $6.52 | $16,613 | $0 | $16,613 | 0.50% | $83 | 1.06% | $176 |
| 16,000 Lumen - Decorative | 799 | $8.27 | $6,608 | $0 | $6,608 | 0.50% | $33 | 1.06% | $70 |
| 22,000 Lumen | 0 | $8.26 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 27,500 Lumen | 5,601 | $9.59 | $53,714 | $0 | $53,714 | 0.50% | $269 | 1.06% | $569 |
| 27,500 Lumen - Decorative | 143 | $11.93 | $1,706 | $0 | $1,706 | 0.50% | $9 | 1.06% | $18 |
| 50,000 Lumen | 10,133 | $14.00 | $141,862 | $0 | $141,862 | 0.50% | $709 | 1.06% | $1,504 |
| 50,000 Lumen - Decorative | 157 | $15.56 | $2,443 | $0 | $2,443 | 0.50% | $12 | 1.06% | $26 |
| *Metal Halide Lamps* | | | | | | | | | |
| 9,000 Lumen - Decorative | 702 | $9.19 | $6,451 | $0 | $6,451 | 0.50% | $32 | 1.06% | $68 |
| 12,000 Lumen | 1,617 | $13.57 | $21,943 | $0 | $21,943 | 0.50% | $110 | 1.06% | $233 |
| 12,000 Lumen - Decorative | 225 | $11.09 | $2,495 | $0 | $2,495 | 0.50% | $12 | 1.06% | $26 |
| 19,500 Lumen | 518 | $13.71 | $7,102 | $0 | $7,102 | 0.50% | $36 | 1.06% | $75 |
| 19,500 Lumen - Decorative | 6,034 | $14.13 | $85,260 | $0 | $85,260 | 0.50% | $426 | 1.06% | $904 |
| 32,000 Lumen | 544 | $14.58 | $7,932 | $0 | $7,932 | 0.50% | $40 | 1.06% | $84 |
| 32,000 Lumen - Decorative | 669 | $15.79 | $10,564 | $0 | $10,564 | 0.50% | $53 | 1.06% | $112 |
| *Fluorescent Lamps* | | | | | | | | | |
| 1,000 Lumen | 0 | $3.75 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 21,800 Lumen | 83 | $13.92 | $1,155 | $0 | $1,155 | 0.50% | $6 | 1.06% | $12 |
| *Subtotal kWh* | 5,219,065 | | $660,059 | $0 | $660,059 | | $3,300 | | $6,997 |
| *Unbilled* | | | | | | | | | |
| *Total* | 5,219,065 | | $660,059 | $0 | $660,059 | | $3,300 | | $6,997 |
| *Customer* | 221 | | | | | | | | |
| **2b - Full Maintenance (No New Service)** | | | | | | | | | |
| *Incandescent Lamps* | | | | | | | | | |
| 6,000 Lumen | 36 | $17.73 | $638 | $0 | $638 | 0.50% | $3 | 1.06% | $7 |
| 10,000 Lumen | 12 | $23.40 | $281 | $0 | $281 | 0.50% | $1 | 1.06% | $3 |
| *Mercury Vapor Lamps* | | | | | | | | | |
| 7,000 Lumen | 42 | $8.03 | $337 | $0 | $337 | 0.50% | $2 | 1.06% | $4 |
| 20,000 Lumen | 0 | $15.30 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 54,000 Lumen | 96 | $32.48 | $3,118 | $0 | $3,118 | 0.50% | $16 | 1.06% | $33 |
| *Sodium Vapor Lamps* | | | | | | | | | |
| 5,600 Lumen | 4,275 | $4.68 | $20,007 | $0 | $20,007 | 0.50% | $100 | 1.06% | $212 |
| 9,500 Lumen | 14,686 | $6.16 | $90,466 | $0 | $90,466 | 0.50% | $452 | 1.06% | $959 |
| 16,000 Lumen | 1,259 | $7.47 | $9,405 | $0 | $9,405 | 0.50% | $47 | 1.06% | $100 |
| 22,000 Lumen | 0 | $9.44 | $0 | $0 | $0 | 0.50% | $0 | 1.06% | $0 |
| 27,500 Lumen | 2,408 | $10.99 | $26,464 | $0 | $26,464 | 0.50% | $132 | 1.06% | $281 |
| 50,000 Lumen | 1,967 | $16.02 | $31,511 | $0 | $31,511 | 0.50% | $158 | 1.06% | $334 |
| *Metal Halide Lamps* | | | | | | | | | |
| 12,000 Lumen | 1,188 | $15.58 | $18,509 | $0 | $18,509 | 0.50% | $93 | 1.06% | $196 |
| 19,500 Lumen | 724 | $15.73 | $11,389 | $0 | $11,389 | 0.50% | $57 | 1.06% | $121 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 32,000 Lumen | 881 | $16.72 | $14,730 | $0 | $14,730 | 0.50% | $74 | 1.06% | $156 |
| 107,000 Lumen | 96 | $33.05 | $3,173 | $0 | $3,173 | 0.50% | $16 | 1.06% | $34 |
| *Subtotal kWh* | 1,644,140 | | $230,028 | $0 | $230,028 | | $1,150 | | $2,438 |
| *Unbilled* | | | | | | | | | |
| *Total* | 1,644,140 | | $230,028 | $0 | $230,028 | | $1,150 | | $2,438 |
| *Customer* | 99 | | | | | | | | |
| | | | | | | | | | |
| kWh Street Lighting | 56,516,774 | | $4,144,867 | $0 | $4,144,867 | | $20,724 | | $43,936 |
| Customers | 839 | | | | | | | | |
| Unbilled | | | $0 | | $0 | | | | |
| Total | 56,516,774 | | $4,144,867 | $0 | $4,144,867 | | $20,724 | | $43,936 |
| | | | | | | | | | |
| **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 | 1.34% | $12,557 | 2.85% | $26,707 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Total | 17,536,445 | | $1,234,602 | $0 | $1,234,602 | | $12,557 | | $26,707 |
| | | | | | | | | | |
| **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 | 0.90% | $4,673 | 1.92% | $9,970 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Total | 6,177,947 | | $682,028 | $0 | $682,028 | | $4,673 | | $9,970 |
| | | | | | | | | | |
| **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 | 2.80% | $812 | 5.96% | $1,729 |
| All add'l kWh | 0 | 5.7472 ¢ | $0 | $0 | $0 | 2.80% | $0 | 5.96% | $0 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Subtotal | 423,833 | | $80,422 | $0 | $80,422 | | $812 | | $1,729 |
| *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 | 2.80% | $4,012 | 5.96% | $8,540 |
| All add'l kWh | 963,969 | 4.7169 ¢ | $45,469 | $0 | $45,469 | 2.80% | $1,273 | 5.96% | $2,710 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Subtotal | 3,624,867 | | $395,504 | $0 | $395,504 | | $5,285 | | $11,250 |
| Total | 4,048,700 | | $475,926 | $0 | $475,926 | | $6,098 | | $12,979 |
| | | | | | | | | | |
| **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 | 0.86% | $28,844 | 1.83% | $61,378 |
| kW over 15 (Oct - Apr) | 347,761 | $8.70 | $3,025,521 | $0 | $3,025,521 | 0.86% | $26,019 | 1.83% | $55,367 |
| 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 | 0.86% | $298,169 | 1.83% | $634,475 |
| All Add'l kWh (May - Sept) | 309,000,008 | 6.5783 ¢ | $20,326,948 | ($33,973) | $20,292,975 | 0.86% | $174,520 | 1.83% | $371,361 |
| First 1,500 kWh (Oct - Apr) | 424,820,226 | 10.8000 ¢ | $45,880,584 | ($76,682) | $45,803,902 | 0.86% | $393,914 | 1.83% | $838,211 |
| All Add'l kWh (Oct - Apr) | 361,090,369 | 6.0567 ¢ | $21,870,160 | ($36,554) | $21,833,606 | 0.86% | $187,769 | 1.83% | $399,555 |
| Seasonal Service | 0 | $120.00 | $0 | | $0 | | | | |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Total | 1,390,888,211 | | $139,102,851 | ($205,253) | $138,897,598 | | $1,109,235 | | $2,360,349 |
| | | | | | | | | | |
| **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 | 1.15% | $0 | 2.45% | $0 |
| On-Peak kW (Oct - Apr) | 16,065 | $11.19 | $179,767 | $0 | $179,767 | 1.15% | $2,067 | 2.45% | $4,404 |
| 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 | 1.15% | $606 | 2.45% | $1,292 |
| On-Peak kWh (Oct - Apr) | 3,934,668 | 3.9511 ¢ | $155,463 | $0 | $155,463 | 1.15% | $1,788 | 2.45% | $3,809 |
| Off-Peak kWh | 5,030,285 | 3.4002 ¢ | $171,040 | $0 | $171,040 | 1.15% | $1,967 | 2.45% | $4,190 |
| **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 | 1.39% | $9,603 | 2.95% | $20,381 |
| On-Peak kW (Oct - Apr) | 50,080 | $9.47 | $474,258 | $0 | $474,258 | 1.39% | $6,592 | 2.95% | $13,991 |
| On-Peak kWh (May-Sept) | 7,647,176 | 4.6531 ¢ | $355,831 | $0 | $355,831 | 1.39% | $4,946 | 2.95% | $10,497 |
| On-Peak kWh (Oct-Apr) | 10,898,121 | 3.4989 ¢ | $381,314 | $0 | $381,314 | 1.39% | $5,300 | 2.95% | $11,249 |
| Off-Peak kWh | 27,727,401 | 2.9225 ¢ | $810,333 | $0 | $810,333 | 1.39% | $11,264 | 2.95% | $23,905 |
| Subtotal | | | $3,559,306 | $0 | $3,559,306 | | $44,134 | | $93,718 |
| Unbilled | 0 | | $0 | | $0 | | | | |
| Total (Aggregated) | 56,282,445 | | $4,575,592 | $0 | $4,575,592 | | $44,134 | | $93,718 |
| | | | | | | | | | |
| **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 | 0.95% | $91,268 | 2.03% | $195,025 |
| kWh High Load Hours | 237,232,647 | | $8,613,813 | $0 | $8,613,813 | 0.95% | $81,831 | 2.03% | $174,860 |
| kWh Low Load Hours | 298,488,523 | | $7,977,879 | $0 | $7,977,879 | 0.95% | $75,790 | 2.03% | $161,951 |
| Total | 535,721,170 | | $27,958,751 | $0 | $27,958,751 | | $248,889 | | $531,837 |
| | | | | | | | | | |
| **Contract 2** | | | | | | | | | |
| Customer Charge | 12 | | | | | | | | |
| Interruptible kWh | 795,798,676 | | $35,062,890 | $0 | $35,062,890 | 1.46% | $511,918 | 3.11% | $1,090,456 |
| Total | 795,798,676 | | $35,062,890 | $0 | $35,062,890 | | $511,918 | | $1,090,456 |
| | | | | | | | | | |
| **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 | $17,327,437 | $36,819,469 |

Rocky Mountain Power
Exhibit RMP___(RMM-3)
Docket No. 20-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariff

March 2020

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

**Third Revision of Sheet No. 94.11**
**P.S.C.U. No. 50** **Canceling Second Revision of Sheet No. 94.11**

## 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 | 1.70% |
| Schedule 2 | 1.70% |
| Schedule 2E | 1.70% |
| Schedule 3 | 1.70% |
| Schedule 6 | 2.25% |
| Schedule 6A | 3.42% |
| Schedule 6B | 2.25% |
| Schedule 7* | 1.06% |
| Schedule 8 | 2.45% |
| Schedule 9 | 2.95% |
| Schedule 9A | 3.27% |
| Schedule 10 | 2.18% |
| Schedule 11* | 1.06% |
| Schedule 12* | 1.06% |
| Schedule 15 (Traffic and Other Signal Systems) | 1.92% |
| Schedule 15 (Metered Outdoor Nighttime Lighting) | 2.85% |
| Schedule 21 | 5.96% |
| Schedule 22 | 2.95% |
| Schedule 23 | 1.83% |
| 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.

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

**~~Second~~ Third Revision of Sheet No. 94.11**

**P.S.C.U. No. 50** **Canceling ~~First~~ Second Revision of Sheet No. 94.11**

## 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~~0~~.7~~8~~0% |
| Schedule 2 | 1~~0~~.7~~8~~0% |
| Schedule 2E | 1~~0~~.7~~8~~0% |
| Schedule 3 | 1~~0~~.7~~8~~0% |
| Schedule 6 | 2~~1~~.25~~06~~% |
| Schedule 6A | 3~~1~~.42~~61~~% |
| Schedule 6B | 2~~1~~.25~~06~~% |
| Schedule 7* | 1~~0~~.06~~50~~% |
| Schedule 8 | 2~~1~~.4~~1~~5% |
| Schedule 9 | 2~~1~~.95~~39~~% |
| Schedule 9A | 3~~1~~.27~~54~~% |
| Schedule 10 | 2~~1~~.18~~02~~% |
| Schedule 11* | 1~~0~~.06~~50~~% |
| Schedule 12* | 1~~0~~.06~~50~~% |
| Schedule 15 (Traffic and Other Signal Systems) | 1~~0~~.92~~0~~% |
| Schedule 15 (Metered Outdoor Nighttime Lighting) | 2~~1~~.85~~34~~% |
| Schedule 21 | 5~~2~~.96~~80~~% |
| Schedule 22 | 2~~1~~.95~~39~~% |
| Schedule 23 | 1~~0~~.83~~6~~% |
| 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.

Issued by authority of Report and Order of the Public Service Commission of Utah in Docket No. ~~19~~20-035-01/Docket No. ~~19~~20-035-T0~~1~~1

**FILED:** ~~July 18, 2019~~March 16, 2020 **EFFECTIVE:** ~~August 1, 2019~~March 1, 2021