ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

March 15, 2022

VIA ELECTRONIC FILING

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. 22-035-01**
Rocky Mountain Power's Application for Approval of the 2022 Energy Balancing Account
Rocky Mountain Power's Application

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 for Approval of the 2022 Energy Balancing Account. The Application is accompanied by the direct testimonies, exhibits and workpapers of Mr. Jack Painter and Mr. Robert M. Meredith and the applicable filing requirements.

The enclosed proposed tariff sheet is associated with Tariff P.S.C.U No. 51 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 sheet does 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
Senior Vice President, Regulation and Customer & Community Solutions

cc: Service List – Docket No. 22-035-01

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Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION FOR APPROVAL OF THE 2022 ENERGY BALANCING ACCOUNT	))))	Docket No. 22-035-01

ROCKY MOUNTAIN POWER'S APPLICATION FOR APPROVAL OF THE 2022 ENERGY BALANCING ACCOUNT

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 No. 94 ("Tariff Schedule 94"), requesting approval to recover approximately $90.6 million in deferred EBA Costs ("EBAC"). The $90.6 million deferral includes the following components: (1) approximately $107.6 million of EBA-related costs; (2) a credit of approximately $22.4 million for sales made to a special contract customer; (3) approximately $2.9 million in costs for Utah situs resources; and (4) a charge of approximately $2.6 million in interest.

The Company has included revised Tariff Schedule 94 to recover from customers approximately $90.6 million over 14 months beginning May 1, 2022 on an interim basis through June 30, 2023. This results in an overall increase to retail customers of Tariff Schedule 94 of approximately 1.9 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 Docket Nos. 16-035-T05 and 09-035-15 by orders issued May 16, 2016, February 16, 2017, November 14, 2019, March 13, 2020, and consistent with any changes approved in pending Docket No. 22-035-T05 (together, the "EBA Order").

The proposed EBA rate increase reflected in this Application represents an EBA rate adjustment under Tariff Schedule 94 as set forth above. It is allocated to rate schedules consistent with the base EBA amounts approved by the Commission in the Company's general rate case filing in Docket No. 20-035-04 (the "2020 GRC"), as more fully explained below. Rocky Mountain Power respectfully requests that, pursuant to the provisions in Tariff Schedule 94, this increase in Utah rates become effective, on an interim basis, May 1, 2022. In addition, the Company proposes that any difference between the 2021 EBA and the final amount collected be amortized when final rates are implemented on July 1, 2023.

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
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1407 West North Temple, Suite 310
Salt Lake City, UT 84116
E-mail: jana.saba@pacificorp.com

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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, OR 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, which provide for a rate effective date on an interim basis of May 1, 2022. Changes to the EBA schedule as well as additional information in support of the interim rate request are provided in more detail in this Application.

6. The EBA deferral calculation consists of three revenue requirement components: NPC, production tax credits ("PTCs") and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchased power expenses, wheeling expenses, less wholesale sales revenue. PTCs are included in the EBA as approved in the Company's 2020 GRC, which are an offset to the Company's federal income taxes based upon actual energy generated at eligible wind-powered generating facilities. Wheeling revenue includes amounts booked to FERC account 456.1, Revenues from Transmission of Electricity of Others. Collectively, the three 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, PTCs and wheeling revenue to the total base EBAC recovered in rates as established in a general rate case. In addition, several

adjustments were made to actual NPC this year, as described in the direct testimony of NPC Specialist Jack Painter.

8. The deferral period for this Application is the 12-month period beginning January 1, 2021 through December 31, 2021 ("Deferral Period").

9. The request in this Application includes four main components: (1) approximately $107.6 million of EBA-related costs; (2) a credit of approximately $22.4 million for sales made to a special contract customer; (3) approximately $2.9 million in costs for Utah situs resources; and (4) a charge of approximately $2.6 million of interest.

10. For the Deferral Period, base NPC were set in the Company's 2020 general rate case, Docket No. 20-035-04, at approximately $1.431 billion ("Base NPC") and became effective January 1, 2021.

11. Actual NPC were higher than Base NPC during the Deferral Period due to an increase in purchased power expenses, increases in natural gas and coal fuel expenses, an increase in wheeling and other expenses, and a decrease in wholesale sales and PTCs.

12. The Company calculated the EBA Deferral Amount using the Commission Order Method consistent with the stipulation approved by the Commission in the 2020 GRC, as set forth in detail in **Exhibit RMP___(JP-1)**, attached to Mr. Painter'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. Painter's **Exhibit RMP___(JP-1),** shows the detailed calculation of the EBA Deferral Amount. Adjusted Actual Total NPC from January 1, 2021, through December 31, 2021, were

approximately $1.694 billion, compared to the $1.431 billion Base NPC being used in this case.

14. As shown in **Exhibit RMP___(JP-1)**, the difference between Base NPC and Actual NPC was due to a $42 million reduction in wholesale sales, a $125 million increase in purchased power expense, a $52 million increase in natural gas expense, a $30 million increase in coal fuel expense, and a $13 million increase in wheeling and other expenses. Mr. Painter further discusses the drivers causing the variance in net power costs for the deferral period.

15. As showing in **Exhibit RMP___(JP-1)**, Utah's allocated NPC before wheeling revenues were approximately $757 million. After crediting Utah-allocated production tax credits of approximately $97 million and wheeling revenues of approximately $72.2 million, Utah actual EBAC were approximately $588 million shown on line 4, or $23.04 per megawatt-hour ("MWh"), shown on line 6.

16. In comparison, Utah Base EBAC were approximately $467 million shown on line 10, after crediting Utah-allocated production tax credits of approximately $106 million and wheeling revenues of approximately $50.6 million shown on lines 8 and 9, respectively, or $18.81 per MWh, shown on line 12. The monthly difference between lines 6 and 12 applied to Utah's 2021 load produces the deferred EBAC of approximately $107.6 million, shown on line 14.

17. An adjustment for sales to a special contract customer of approximately $22.4 million, after applying a deadband, is shown on line 17. An adjustment related to the Utah situs resources, namely the Utah Subscriber Solar program, the Utah Transition Program for Customer Generators and a fee for the Energy Imbalance Market Body of

State Regulators of approximately $2.9 million is shown on line 18. A charge for interest of approximately $1.5 million for the Deferral Period is shown on line 23. A charge for interest of approximately $871 thousand (from January 2022 through March 2022) is shown on line 25 and $230 thousand for April 2022 is shown on line 26. The total ending deferral amount of approximately $90.6 million is shown on line 27.

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

Annual EBA Calculation

Calendar Year 2021 EBA Deferral			*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$	23.04	*Line 6*
Base EBA ($/MWh)		18.81	*Line 12*
$/MWh Differential	**$**	**4.22**	
Utah Sales (MWh)		25,523,328	*Line 5*
EBA Deferrable*	$	107,599,353	*Line 14*
Special Contract Customer Adjustment*		(22,400,376)	*Line 17*
Utah Situs Resource Adjustment*		2,866,745	*Line 18*
Total Deferrable	$	88,065,722	*Line 19*
Interest Accrued through December 31, 2021		1,451,080	*Line 23*
Interest Accrued January 1, 2022 through March 31, 2022		871,124	*Line 25*
Interest Accrued April 1, 2022 through April 30, 2022		229,736	*Line 26*
Requested EBA Recovery	**$**	**90,617,662**	*Line 27*

** Calculated monthly*

EBA Amortization and Schedule Changes

19. Certain events have recently occurred that allow changes to the timing and schedule of the EBA as follows:

i. In the 2021 Utah Legislative Session, the legislature modified the energy balancing account statute, § 54-7-13-5(2)(l)(ii), to add a new 300-day statutory deadline for the Commission to issue a final order and modified Utah Code Ann. § 54-7-13.5(2)(k) to permit interim rates;

ii. On February 23, 2021, in Docket No. 21-035-01, the Commission approved a Settlement Stipulation ("2021 Settlement") that stated rates under Schedule 94 should not change on March 1, 2022 and instead that the existing rates under Schedule 94 would remain in place through April 30, 2022, which would effectively recover the approved $6.6 million request in that proceeding over two months in March and April of 2022. The signatory parties of the 2021 Settlement envisioned that the next rate change under Schedule 94 would be the interim rate change on May 1, 2022 as presented in this Application.

20. In response to these events and circumstances, PacifiCorp submitted a tariff filing in Docket No. 22-035-T05 that is pending with the Commission that contains the following proposed changes to Schedule 94 to address these circumstances:

i. For the 2022 EBA, interim rates will become effective on May 1, 2022 and be effective for a total of 14 months until June 30, 2023.

ii. The procedural schedule for the 2022 EBA will adjust to accommodate the 300-day statutory deadline for a Commission order by January 9, 2023.

iii. Beginning in the 2023 EBA, the Company will file its annual EBA applications on May 1 of each year, for interim rates on July 1.

21. With the foregoing changes, the Company requests the interim rates for this EBA to be effective on May 1, 2022 and continue for 14 months until June 30, 2023, which offers an additional benefit of collecting the relatively large EBA request in this docket over a longer period, helping to mitigate the rate impact to customers.

Proposed Interim Rate

22. In the 2021 Utah Legislative Session, Utah Code Ann. § 54-7-13.5(2)(k) permits the Commission to consider an interim rate request made as part of an electric corporation's filing of an energy balancing account. Prior to interim rate becoming effective, the Commission must hold a hearing on the interim rate request to consider whether the Company has made an adequate prima facie showing that the proposed

interim rate appears consistent with prior years' filing and is more likely to reflect actual power costs than the current base rates.

23. In accordance with Utah Code Ann. § 54-7-13.5(2)(k), Rocky Mountain Power hereby requests the 2021 EBA recovery amount of $90.6 million be collected on an interim basis beginning May 1, 2022 subject to rate refund or surcharge.

24. This proposed rate change is consistent with prior years filing because it uses substantially similar methodologies to arrive at total EBAC. Using these methodologies, the Company has determined that EBAC has increased and is more likely to reflect actual power costs than the current base rates. The interim rates requested by the Company will be subject to future audit by the Division of Public Utilities and evaluation at a hearing by other parties.

25. Rocky Mountain Power hereby requests the Commission issue a notice of scheduling order so that a hearing date may be scheduled to facilitate interim rates becoming effective May 1, 2022.

Proposed Tariff Sheets

26. The Company's proposal is to spread the deferred EBAC across customer classes consistent with an EBA Allocator that allocates the Base EBA amounts approved by the Commission in the 2020 GRC by cost of service factor 10 or factor 30 for different FERC accounts, as appropriate. Allocation to the customer classes is shown in **Exhibit RMP___(RMM-1)**, attached to the direct testimony of Mr. Meredith.

27. The Company proposes to allocate the EBA deferral for CY 2021 to those customer classes that are not reflected in the cost of service study used in the 2020 GRC,

such as Schedule 31 and Schedule 32 customers, as described in Mr. Meredith's direct testimony.

28. 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 $40.2 million, or 1.9 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**
Residential	
Schedules 1, 2, 3	1.6%
General Service	
Schedule 23	1.7%
Schedule 6	1.9%
Schedule 8	2.4%
Schedule 9	3.3%
Irrigation	
Schedule 10	2.1%
Public Street and Area Lighting Schedules	
Schedules 7, 11, 12	1.5%
Schedule 15	3.2%

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission:

1. Issue a notice of scheduling conference so parties may confer on a procedural schedule including a hearing date for approval of an interim rate change.

2. Approve rates in Tariff Schedule 94 to recover the costs identified in this Application, as filed, with an effective date on an interim basis of May 1, 2022 through June 30, 2023.

DATED this 15th day of March 2022.

Respectfully submitted,

ROCKY MOUNTAIN POWER

Emily Wegener
____

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CERTIFICATE OF SERVICE

Docket No. 22-035-01

I hereby certify that on March 15, 2022, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services

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Division of Public Utilities

dpudatarequest@utah.gov

Assistant Attorney General

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Mary Penfield
Adviser, Regulatory Operations

Rocky Mountain Power
Docket No. 22-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Jack Painter

March 2022

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 Jack Painter and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Specialist.

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Arts degree in Business Administration with a Finance major from Washington State University in 2007. I have been employed by PacifiCorp since 2008 and have held positions in the regulation and jurisdictional loads departments. I joined the regulatory net power costs group in 2019 and assumed my current role as a net power cost specialist in 2020.

Q. Have you testified in previous regulatory proceedings?

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

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, 2021 through December 31, 2021 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $90.6 million for excess EBA-related costs, including interest, 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. Is an additional witness presenting testimony specifically for the EBA and Electric Service Schedule No. 94 ("Schedule 94") in this case?

A. Yes. Mr. Robert M. Meredith, Director, Pricing & Tariff Policy, provides testimony on the proposed 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 $90.6 million in deferred costs, comprised of $107.6 million of EBA-related costs, a credit of $22.4 million for sales made to a special contract customer, a $2.9 million adjustment for Utah situs resources, and approximately $2.6 million of interest.

Q. Are there any changes to the EBA calculation?

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

- Base NPC rates have been updated to reflect the Company's most recent 2020 general rate case ("GRC") filing in Docket No. 20-035-04.
- Production Tax Credits ("PTC") are included in the EBA calculation as part of the Company's 2020 GRC filing in Docket No. 20-035-04.

- The interest calculation for the period after the deferral has been updated to reflect the Company's recent proposal to implement interim rates, which is pending Commission approval in Docket No. 22-035-T05.[1]

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

Table 1
Annual EBA Calculation

Calendar Year 2021 EBA Deferral			*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$	23.04	*Line 6*
Base EBA ($/MWh)		18.81	*Line 12*
$/MWh Differential	**$**	**4.22**	
Utah Sales (MWh)		25,523,328	*Line 5*
EBA Deferrable*	$	107,599,353	*Line 14*
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Interest Accrued April 1, 2022 through April 30, 2022		229,736	*Line 26*
Requested EBA Recovery	**$**	**90,617,662**	*Line 27*

** Calculated monthly*

The EBA deferral of $107.6 million is calculated as the difference between the Actual NPC, PTC's and wheeling revenue and the Base NPC, PTC's and wheeling revenue,

[1] PacifiCorp's tariff filing was filed March 2, 2022 in Docket Nos. 22-035-T05 and 09-035-15 to implement interim rates in Schedule 94 on May 1, 2022.

as established in the 2020 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 three revenue requirement components: NPC, PTC's and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. PTC's are credits the Company receives for generation at certain Company-owned wind facilities that are included as an offset to the Company's federal income taxes and reduce net power costs for rate-making purposes. Wheeling revenue includes amounts booked to FERC account 456.1 and revenues from transmission of electricity of others. Collectively, these three components are known in the Company's EBA tariff, Schedule 94, as Energy Balancing Account Costs ("EBAC").

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 based on the 2020 PacifiCorp Inter-Jurisdictional Allocation 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 $1.694 billion. 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

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;
- Situs assignment of Reasonable Energy Price adjustments to QF's
- 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 ("GAAP");
- Electric Service Schedule No. 32 ("Schedule 32") and Schedule 34 ("Schedule 34") contracts; and
- An adjustment for costs related to participation in the Western Power Pool's ("WPP") Western Resource Adequacy Program ("WRAP").
- Situs assignment of the EIM Body of State Regulators ("BOSR") fees charged for commission related work as a participant in the EIM.

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 2020 GRC set the Base NPC effective January 1, 2021, in Docket No. 20-035-04 using the Commission Order Method, which was originally approved by the Commission in Docket No. 09-035-15. Exhibit RMP___(JP-1) calculates the EBA deferral using the Commission Order Method for the entire Deferral Period.

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

A. Yes. In accordance with the Commission's orders dated March 2, 2011, and February 16, 2017, in Docket No. 09-035-15, carrying charges accrue on the monthly EBA deferral. Effective January 1, 2020, the carrying charge is 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. Additionally, the calculation of carrying charges has been updated to reflect interim rates and a 14-month amortization period as requested in Docket No. 20-035-T05 by reducing the time frame from the end of the deferral period until collection of the deferral begins to 4 months as described in the Application.

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 2022 EBA, the adjustment for sales made to a special contract customer is a $22.4 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 and expenses, namely the Utah Subscriber Solar Program, the Utah Transition Program for Customer Generators, and the EIM BOSR fees charged for commission related work as a participant in the EIM.

Q. Please describe the Utah Subscriber Solar Program.

A. The Commission approved the "Subscriber Solar Program Rider - Optional" Electric Service Schedule No. 73 ("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.[2] 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 are no load adjustments and no change in allocation factors due to the program. The EBA adjustment for Subscriber Solar is approximately $48 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 Electric Service Schedule No. 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

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

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 $2.8 million.

Q. Please explain the purpose of the EIM BOSR.

A. The EIM BOSR is a body that addresses the regional nature of the EIM through the EIM governance process. The purpose of the EIM BOSR is to provide "a forum for state commissioners to (1) select a voting member of the EIM Governing Body Nominating Committee, (2) learn about and discuss the EIM and CAISO markets, and (3) express a common position in CAISO stakeholder processes or the EIM Governing Body on EIM issues."[3]

Q. Please describe new fee that is associated with the EIM BOSR.

A. As described by the EIM BOSR, the fee supports the BOSR's expenses and support the body's goal that "consistent, and informed regulator engagement on regional market operations and developments is crucial to efficient and sustainable markets that deliver public benefits."[4]

Q. Please describe the adjustment to the EBA for the EIM BOSR Fees.

A. The Utah allocated cost in the EBA is $44,639.

[3] *EIM BOSR Energy Imbalance Market Body of State Regulators*, WESTERN INTERSTATE ENERGY BOARD ofpc2022), https://www.westernenergyboard.org/energy-imbalance-market-body-of-state-regulators/.
[4] ibid.

Q. What is the WPP WRAP?

A. The WPP WRAP is the new regional resource adequacy initiative that is being implemented by many utilities and power producers across the west to ensure that the region is better able to plan for its regional resource adequacy needs.

Q. Please explain the WPP WRAP Fee.

A. There are three main components of the WRAP fee that are necessary to meet the Company's resource adequacy requirements for the WPP WRAP. First is facilitation and coordination services, include the use of staff resources related to facilitation and coordination services provided by WPP Corporation in connection with the Phase 3A Scope of Work. Secondly, WPP will bill to the participants the expenses the WPP Corporation incurs directly to perform the Phase 3A Scope of Work, including costs associated with contracting for a Program Operator. Finally, there are binding program preparation costs including preparation for Federal Energy Regulatory Commission filings, setting up an independent board and preparing the WPP Corporation to undertake the obligations required to house the program as a public utility under the Federal Power Act.

Q. Please describe the adjustment to the EBA for the WPP WRAP Fees.

A. The total-Company cost for 2021 is $129,720 and the Utah allocated cost in the EBA is $57,825.

Q. Please describe the adjustment to the EBA for the Schedule 32 and 34 Contracts.

A. Schedule 32 and Schedule 34 are unique retail service options available to any customer who would otherwise qualify for Electric Service Schedule Nos. 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. Purchase power agreement costs and generation from renewable energy facilities for the customer are removed from NPC in the EBA and any excess generation is purchased at Electric Service Schedule No. 37 avoided costs rates.

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 $1.694 billion, approximately $263 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	**$**	**1,431**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		42
Purchased Power Expense		125
Coal Fuel Expense		30
Natural Gas Expense		52
Wheeling and Other Expense		13
Total Increase/(Decrease)		**263**
Total Company NPC Difference	**$**	**263**
Adjusted Actual NPC	**$**	**1,694**

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

A. The Base NPC for the 2022 EBA was set in the 2020 GRC and became effective January 1, 2021. Base NPC used a test period of 12 months from January 2021 through December 2021 and set total-Company Base NPC at $1.431 billion.

Q. Please describe some of the weather events that impacted NPC.

A. 2021 was characterized by a large number of extreme and unforeseeable weather events. Collectively, they shaped actual NPC throughout the year. For instance, February 2021 saw a polar vortex that brought record cold temperatures to a significant portion of the United States from February 6, 2021 through February 22, 2021 with temperatures falling as much as 25-50 degrees Fahrenheit below average. Combining this event with the 2021 Texas power crisis created a perfect storm and market prices were significantly higher during this period.

After the polar vortex, the Company experienced another significant impact to NPC with the Western North America heat wave, a 13 day long extreme weather event that occurred between June 25, 2021 and July 7, 2021 that saw a temperature peak of 119 degrees Fahrenheit in the Western United States and had a significant impact on market prices for June and July as compared to the same period in 2020.

Q. Please describe how drought conditions have an effect on NPC.

A. Ongoing drought has caused negative effects to NPC because it impacts the availability of hydro resources. In 2021, actual generation from hydro resources were 837,340 MWhs, or 23 percent lower, than forecasted generation. Unrealized hydro MWhs need to be replaced to meet customer demand through system dispatch of other resources, reducing market sales, increasing market purchases or any combination of these options. The estimated impact to total-Company NPC of the decreased hydro MWhs due to drought is $39.3 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 $42 million reduction in wholesale sales, a $125 million increase in purchased power expense, a $52 million increase in natural gas expense, a $30 million increase in coal fuel expense, and a $13 million increase 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 due to a reduction in the wholesale sales volumes of market transactions (represented in GRID as short-term firm and system balancing sales).

Revenue from market transactions is approximately $42 million lower than Base NPC due to a lower volume of market sales transactions, but offset by increased market prices. The average price of actual market sales transactions was $5.82/MWh, or 18 percent, higher than the average price in Base NPC. Actual wholesale market volumes were 2,203 gigawatt-hours ("GWh"), or 31 percent, lower than the Base NPC.

Q. Please explain the changes in purchased power expense.

A. The increase in purchased power expense relative to Base NPC was due to an increase in the average price of market purchase transactions (represented in GRID as short-term firm and system balancing purchases) with a significant impact tied to the polar vortex in February, the Western North America heat wave in June and July, and drought.

Expenses from market transactions increased by $303.6 million compared to Base NPC. Actual market purchases were 860 GWh (24 percent) higher than Base NPC and the average price of actual market purchases transactions was $65.47/MWh (381 percent) higher than Base NPC.

For the polar vortex in February, the Mid-Columbia market hub saw average market prices increase 188 percent for peak hours and 151 percent for off-peak hours while the Four Corners market hub saw average market prices increase 520 percent for peak hours and 242 percent for off-peak hours.

With the heat wave in June and July, the Mid-Columbia market hub saw an average increase in high load hour market prices of 620 percent and 560 percent respectively while the Four Corners market hub saw an average increase in high load hour market prices of 464 percent and 150 percent, respectively. Combining the impact of increased actual Utah sales in June and July over base sales and higher market prices results in a NPC variance of $78.4 million above base NPC on a Utah-allocated basis.

Q. Please explain the changes in wheeling expenses.

A. The increase in wheeling expenses relative to Base NPC was primarily due to an increase in short-term firm wheeling expense of $11.8 million.

Q. Please discuss the changes in coal fuel expense.

A. The principal driver of the coal fuel expense increase is a coal generation volume increase of 3,496 GWh (12 percent) compared to Base NPC. The average cost of coal generation decreased slightly from $21.45/MWh in Base NPC to $20.03/MWh in the Deferral Period, but the higher generation results in an overall increase of approximately $30 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 $52 million compared to Base NPC. The main driver of the increase is the average cost of natural gas generation increased from $20.73/MWh in Base NPC to $26.40/MWh (27 percent) in the Deferral Period, but increased costs were offset by a decrease in natural gas generation volume of 1,116 GWh (8 percent) below Base NPC during the Deferral Period.

Natural gas market prices were also impacted by the extreme weather events in 2021. At the Opal natural gas trading hub, average market prices were 790 percent higher in February 2021 as compared to the same period last year and June and July 2021 were 115 percent and 135 percent higher respectively. Overall, gas prices at Opal were 137 percent higher in 2021 as compared to 2020.

IMPACT OF PARTICIPATING IN THE EIM

Q. Are the benefits from participating in the EIM 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. For 2021, CAISO's EIM benefits report shows $115.5 million in EIM benefits for PacifiCorp and $391.4 million since the inception of the EIM.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JP-1)
Docket No. 22-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jack Painter

Monthly EBA Deferral Calculation

March 2022

Rocky Mountain Power
Exhibit RMP___(JP-1) Page 1 of 1
Docket No. 22-035-01
Witness: Jack Painter

Utah Energy Balancing Account Mechanism
January 1, 2021 - December 31, 2021
Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor)

Line No.		Reference	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
	Actual: Utah Allocated														
1	NPC	(2.1)	$ 53,561,971	$ 51,677,981	$ 54,101,059	$ 52,037,812	$ 53,858,955	$ 89,419,820	$ 104,314,193	$ 73,742,253	$ 52,287,421	$ 58,557,406	$ 50,606,204	$ 63,026,270	$ 757,191,344
2	PTC	(9.1)	(8,005,295)	(9,105,736)	(7,792,001)	(7,949,105)	(7,138,374)	(5,499,973)	(4,917,064)	(6,737,097)	(6,467,295)	(7,695,792)	(11,779,332)	(13,951,225)	(97,038,288)
3	Wheeling Revenue	(4.1)	(3,941,099)	(4,678,638)	(4,198,850)	(4,885,284)	(5,735,117)	(8,190,994)	(9,946,153)	(9,730,952)	(7,407,424)	(5,160,728)	(4,911,129)	(3,435,731)	(72,222,100)
4	Total	∑ Lines 1:3	$ 41,615,577	$ 37,893,606	$ 42,110,208	$ 39,203,423	$ 40,985,464	$ 75,728,853	$ 89,450,975	$ 57,274,204	$ 38,412,703	$ 45,700,886	$ 33,915,743	$ 45,639,313	$ 587,930,956
5	Jurisdictional Sales	(5.2)	2,120,227	1,852,888	1,946,122	1,785,275	1,994,806	2,530,235	2,707,881	2,431,098	2,098,258	1,941,702	1,945,744	2,169,094	25,523,328
6	Actual Utah $/MWh	Line 4 / Line 5	**$ 19.63**	**$ 20.45**	**$ 21.64**	**$ 21.96**	**$ 20.55**	**$ 29.93**	**$ 33.03**	**$ 23.56**	**$ 18.31**	**$ 23.54**	**$ 17.43**	**$ 21.04**	**$ 23.04**
	Base: Utah Allocated														
7	NPC	(3.1)	$ 52,896,516	$ 49,963,481	$ 51,232,250	$ 45,143,308	$ 46,529,610	$ 53,485,781	$ 61,875,110	$ 58,318,910	$ 49,315,103	$ 48,730,667	$ 51,240,255	$ 55,415,210	$ 624,146,199
8	PTC	(9.1)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(106,227,616)
9	Wheeling Revenue	(4.1)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(50,632,163)
10	Total	∑ Lines 7:9	$ 39,824,867	$ 36,891,833	$ 38,160,602	$ 32,071,659	$ 33,457,962	$ 40,414,132	$ 48,803,462	$ 45,247,261	$ 36,243,454	$ 35,659,019	$ 38,168,606	$ 42,343,562	$ 467,286,420
11	Jurisdictional Sales	(5.2)	2,087,756	1,833,770	1,924,709	1,851,240	1,929,518	2,156,059	2,546,774	2,449,322	2,055,691	1,956,778	1,940,943	2,104,828	24,837,388
12	Base Utah $/MWh	Line 10 / Line 11	**$ 19.08**	**$ 20.12**	**$ 19.83**	**$ 17.32**	**$ 17.34**	**$ 18.74**	**$ 19.16**	**$ 18.47**	**$ 17.63**	**$ 18.22**	**$ 19.66**	**$ 20.12**	**$ 18.81**
	Deferral:														
13	$/MWH Differential	Line 6 - Line 12	$ 0.55	$ 0.33	$ 1.81	$ 4.63	$ 3.21	$ 11.19	$ 13.87	$ 5.09	$ 0.68	$ 5.31	$ (2.23)	$ 0.92	$ 4.22
14	EBA Deferrable	Line 5 * Line 13	**$ 1,171,316**	**$ 617,153**	**$ 3,525,056**	**$ 8,274,573**	**$ 6,395,413**	**$ 28,300,997**	**$ 37,560,248**	**$ 12,363,616**	**$ 1,418,752**	**$ 10,316,610**	**$ (4,347,273)**	**$ 2,002,892**	**$ 107,599,353**
15	Special Contract Customer Adjustment Subject to Deadband	(7.1)	231,508	(1,302,183)	12,692	(612,939)	(566,822)	(2,330,802)	(5,422,112)	(2,727,404)	(3,627,374)	(2,976,042)	(1,510,943)	(1,917,954)	(22,750,376)
16	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
17	Total Special Contract Adjustment	Line 15 - Line 16	-	(720,675)	12,692	(612,939)	(566,822)	(2,330,802)	(5,422,112)	(2,727,404)	(3,627,374)	(2,976,042)	(1,510,943)	(1,917,954)	(22,400,376)
18	Utah Situs Resource Adjustment	(8.1)	195,012	(108,670)	657,879	862,963	1,010,819	(398,868)	(65,595)	216,405	160,003	209,793	114,493	12,510	2,866,745
19	Total Incremental EBA Deferral	∑ Lines 14 and Lines 17:18	**$ 1,366,329**	**$ (212,192)**	**$ 4,195,627**	**$ 8,524,597**	**$ 6,839,410**	**$ 25,571,327**	**$ 32,072,541**	**$ 9,852,618**	**$ (2,048,620)**	**$ 7,550,361**	**$ (5,743,723)**	**$ 97,448**	**$ 88,065,722**
	Energy Balancing Account:														
20	Monthly Interest Rate	Note 1	0.32%	0.32%	0.32%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	
21	Beginning Balance	Prior Month Line 24	$ -	$ 1,368,537	$ 1,160,427	$ 5,366,589	$ 13,915,579	$ 20,798,905	$ 46,455,313	$ 78,686,166	$ 88,750,602	$ 86,924,222	$ 94,704,355	$ 89,193,274	$ -
22	Incremental Deferral	Line 19	1,366,329	(212,192)	4,195,627	8,524,597	6,839,410	25,571,327	32,072,541	9,852,618	(2,048,620)	7,550,361	(5,743,723)	97,448	88,065,722
23	Interest	Line 20 * (Line 21 + 50% x Line 22)	2,209	4,082	10,535	24,393	43,916	85,081	158,312	211,818	222,240	229,772	232,642	226,080	1,451,080
24	**Ending Balance**	∑ Lines 21:23	**$ 1,368,537**	**$ 1,160,427**	**$ 5,366,589**	**$ 13,915,579**	**$ 20,798,905**	**$ 46,455,313**	**$ 78,686,166**	**$ 88,750,602**	**$ 86,924,222**	**$ 94,704,355**	**$ 89,193,274**	**$ 89,516,802**	**$ 89,516,802**
25	Interest Accrued January 1, 2022 through March 31, 2022	Line 24 * (1 + 1.0304% / 12) ^ 3 - Line 24													871,124
26	Interest Accrued April 1, 2022 through April 30, 2022	Line 24 and 25 * (1 + 1.0305% / 12) ^ 1 - Line 24 and 25													229,736
27	**Requested EBA Recovery**	∑ Lines 24:25													**$ 90,617,662**

Notes:
1 Interest rate is from Electric Service Schedule No. 300 due to Docket No. 09-035-15/Order Issued November 14, 2019.

Rocky Mountain Power
Docket No. 22-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Robert M. Meredith

March 2022

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 Tariff Policy.

Qualifications

Q. Briefly describe your educational 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 17 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 11 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 February 2022, I assumed my present 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. Jack Painter for the 12-

months ended December 31, 2021 (“2022 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 $40.2 million, or 1.9 percent. This net change is the difference between the current collection level of $37.5 million and the new proposed collection level of $77.7 million for the 2022 EBA. Exhibit RMP___(RMM-1), page 1, shows the net impact by rate schedule.

Proposed EBA Rate Spread

Q. What is the 2022 EBA deferral amount in this case?

A. The total 2022 EBA deferral is $90.6 million, as shown in Table 1 of Mr. Painter’s testimony. As discussed in the Company’s advice filing in Docket No. 22-035-T05 made on March 2, 2022, the Company proposes to recover this amount on an interim basis for the 14 month period from May 1, 2022 through June 30, 2023. To adjust this collection amount to set rates based on the Company’s billing determinants, the Company annualized the EBA deferral by multiplying by twelve fourteenths. This results in a $77.7 million annual EBA collection from customers.

Q. How does the Company propose to allocate the 2021 EBA deferral balance across customer classes?

A. The Company proposes to spread the 2022 EBA deferral across customer rate schedules consistent with the base EBA amounts approved by the Commission in the 2020 general rate case, Docket No. 20-035-04 (“2020 GRC”). The allocators and allocations by rate schedule are shown on page 2 in Exhibit RMP___(RMM-1). To develop EBA allocators by class, the Company allocated each FERC account used within the base

EBA on either the cost of service factor 10 or factor 30 used in the 2020 GRC, as appropriate. The FERC account level class allocation of the base EBA is shown on page 3 in Exhibit RMP___(RMM-1).

Q. How does the Company propose to allocate the 2022 EBA revenue to those customer classes that were not reflected in the EBA Allocators?

A. There are two customer classes—Schedule 31 and Schedule 32—that are subject to the EBA but were not included in the Company's cost of service studies in the 2020 GRC and therefore not reflected in the EBA Allocators. For these customer classes, the Company proposes to apply the same percentage change to these customer classes as Schedule 9.

Q. How does the Company propose to allocate the 2022 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 2022 EBA revenue allocation for Contract Customer 1 is based on the overall 2022 EBA percentage to tariff customers in Utah.

Q. How does the Company propose to collect the 2022 EBA deferral after these adjustments to the EBA Allocators?

A. The results of the 2022 EBA deferral spread based on the EBA Allocator are then proportionally adjusted for all customer classes to collect a total target annual amount of $77.7 million.

Q. What present revenues and billing determinants is the Company proposing to use to allocate the 2022 EBA?

A. The Company proposes using the Commission approved present revenues and billing determinants set forth in its 2020 GRC.

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 2020 GRC forecast Power Charge and Energy Charge revenues. Charges for energy enrolled in the Subscriber Solar program were excluded from this calculation, since loads enrolled in the program no longer pay for the EBA. The EBA rate is a percentage applied to the monthly Power Charges and Energy Charges.

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

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

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

A. Exhibit RMP___(RMM-3) contains the proposed tariff rate revisions for Schedule 94.

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.

Rocky Mountain Power
Exhibit RMP___(RMM-1)
Docket No. 22-035-01
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 2022

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 December 2019
Forecast Period 12 Months Ending December 2021

Line No.	Description (1)	Sch No. (2)	No. of Customers Forecast (3)	MWh Forecast (4)	Present Revenue ($000) Base (5)	Present Revenue ($000) EBA (6)	Present Revenue ($000) Net (7)	Proposed Revenue ($000) Base (8)	Proposed Revenue ($000) EBA (9)	Proposed Revenue ($000) Net (10)	Change Base ($000) (11)	Change Base (%) (12)	Change Net ($000) (13)	Change Net (%) (14)
	Residential													
1	Residential	1,3	857,245	6,776,607	$749,389	$11,114	$760,503	$749,389	$23,055	$772,443	$0	0.0%	$11,940	1.6%
2	Residential-Optional TOD	2/2E	623	6,392	$618	$9	$628	$618	$19	$638	$0	0.0%	$10	1.6%
3	AGA/Revenue Credit	--			$7		$7	$7		$7	$0	0.0%	$0	0.0%
4	**Total Residential**		857,868	6,782,999	$750,014	$11,124	$761,137	$750,014	$23,074	$773,088	$0	0.0%	$11,950	1.6%
	Commercial & Industrial & OSPA													
5	General Service-Distribution	6	13,530	5,789,707	$476,830	$9,495	$486,325	$476,830	$19,073	$495,903	$0	0.0%	$9,578	2.0%
6	General Service-Distribution-Energy TOD	6A	2,807	404,256	$47,104	$1,482	$48,586	$47,104	$1,884	$48,988	$0	0.0%	$402	0.8%
7	*Subtotal Schedule 6*		*16,337*	*6,193,963*	*$523,934*	*$10,977*	*$534,911*	*$523,934*	*$20,957*	*$544,891*	*$0*	*0.0%*	*$9,980*	*1.9%*
8	General Service-Distribution > 1,000 kW	8	249	2,020,703	$148,126	$3,160	$151,286	$148,126	$6,799	$154,925	$0	0.0%	$3,639	2.4%
9	General Service-High Voltage	9	158	4,848,931	$273,347	$7,456	$280,802	$273,347	$16,651	$289,997	$0	0.0%	$9,195	3.3%
10	General Service-High Voltage-Energy TOD	9A	9	41,940	$2,993	$79	$3,072	$2,993	$174	$3,167	$0	0.0%	$95	3.1%
11	*Subtotal Schedule 9*		*167*	*4,890,871*	*$276,340*	*$7,535*	*$283,874*	*$276,340*	*$16,825*	*$293,164*	*$0*	*0.0%*	*$9,290*	*3.3%*
12	Irrigation	10	3,339	206,134	$16,043	$340	$16,383	$16,043	$692	$16,735	$0	0.0%	$351	2.1%
13	Irrigation-Time of Day	10TOD	269	24,258	$1,947	$42	$1,989	$1,947	$85	$2,033	$0	0.0%	$43	2.2%
14	*Subtotal Irrigation*		*3,608*	*230,392*	*$17,990*	*$382*	*$18,373*	*$17,990*	*$777*	*$18,767*	*$0*	*0.0%*	*$394*	*2.1%*
15	General Service-Distribution-Small	23	96,230	1,404,452	$138,042	$2,311	$140,353	$138,042	$4,758	$142,800	$0	0.0%	$2,447	1.7%
16	Back-up, Maintenance, & Supplementary	31	7	189,259	$12,590	$281	$12,871	$12,590	$626	$13,216	$0	0.0%	$345	2.7%
17	Svc. From Ren. Ene. Facilities	32	3	196,650	$13,353	$40	$13,393	$13,353	$89	$13,442	$0	0.0%	$49	0.4%
18	Ren. Ene. Pur. for Qlf. Cust > 5,000 kW	34	1	242,230	$13,028	$0	$13,028	$13,028	$0	$13,028	$0	0.0%	$0	0.0%
17	Contract 1	--	1	617,100	$31,874	$608	$32,482	$31,874	$1,218	$33,092	$0	0.0%	$610	1.9%
19	Contract 2	--	1	705,456	$31,979	$995	$32,974	$31,979	$2,300	$34,280	$0	0.0%	$1,306	4.0%
20	Contract 3	--	1	1,288,626	$62,958	$0	$62,958	$62,958	$0	$62,958	$0	0.0%	$0	0.0%
21	AGA/Revenue Credit	--			$4,797		$4,797	$4,797		$4,797	$0	0.0%	$0	0.0%
22	**Total Commercial & Industrial & OSPA**		116,605	17,979,703	$1,275,011	$26,288	$1,301,299	$1,275,011	$54,348	$1,329,359	$0	0.0%	$28,060	2.2%
	Public Street Lighting													
23	Security Area Lighting	7	6,491	10,498	$1,383	$15	$1,398	$1,383	$36	$1,419	$0	0.0%	$21	1.5%
24	Street Lighting - Company Owned	11	715	13,573	$3,759	$40	$3,799	$3,759	$98	$3,858	$0	0.0%	$58	1.5%
25	Street Lighting - Customer Owned	12	1,229	26,869	$1,385	$15	$1,400	$1,385	$36	$1,421	$0	0.0%	$21	1.5%
26	Metered Outdoor Lighting	15	637	15,963	$781	$16	$797	$781	$53	$835	$0	0.0%	$37	4.7%
27	Traffic Signal Systems	15	2,734	7,776	$803	$12	$815	$803	$26	$829	$0	0.0%	$14	1.8%
28	*Subtotal Public Street Lighting*		11,806	74,679	$8,111	$97	$8,209	$8,111	$250	$8,361	$0	0.0%	$153	1.9%
29	Security Area Lighting-Contracts (PTL)	--	4	7	$1	$0	$1	$1	$0	$1	$0	0.0%	$0	0.0%
30	AGA/Revenue Credit	--			$5		$5	$5		$5		0.0%	$0	0.0%
31	**Total Public Street Lighting**		11,810	74,686	$8,116	$97	$8,214	$8,116	$250	$8,367	$0	0.0%	$153	1.9%
32	**Total Sales to Ultimate Customers**		986,283	24,837,388	$2,033,141	$37,509	$2,070,650	$2,033,141	$77,672	$2,110,814	$0	0.0%	$40,163	1.9%

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 December 2019
Forecast Period 12 Months Ending December 2021

Line No.	Description	Sch No.	Present Revenues ($000)	2020 GRC EBA Allocator ($000)	EBA Deferral 2021 ($000)	EBA Deferral 2021 %
	(1)	(2)	(3)	(4)	(5)	(6)
	Residential					
1	Residential	1,3	$749,389		$23,055	3.1%
2	Residential-Optional TOD	2/2E	$618		$19	3.1%
3	AGA/Revenue Credit	--	$7			
4	**Total Residential**		$750,014	$140,077	$23,074	3.1%
	Commercial & Industrial & OSPA					
5	General Service-Distribution	6	$476,830		$19,073	4.0%
6	General Service-Distribution-Energy TOD	6A	$47,104		$1,884	4.0%
7	*Subtotal Schedule 6*		*$523,934*	*$127,227*	*$20,957*	*4.0%*
8	General Service-Distribution > 1,000 kW	8	$148,126	$41,146	$6,778	4.6%
9	General Service-High Voltage	9	$273,347		$15,880	5.8%
10	General Service-High Voltage-Energy TOD	9A	$2,993		$174	5.8%
11	*Subtotal Schedule 9*		*$276,340*	*$97,457*	*$16,053*	*5.8%*
12	Irrigation	10	$16,043		$693	4.3%
13	Irrigation-Time of Day	10TOD	$1,947		$84	4.3%
14	*Subtotal Irrigation*		*$17,990*	*$4,717*	*$777*	*4.3%*
15	General Service-Distribution-Small	23	$138,042	$28,883	$4,758	3.4%
16	Back-up, Maintenance, & Supplementary	31	$12,590		$731	5.8%
17	Svc. From Ren. Ene. Facilities	32	$13,353		$776	5.8%
18	Ren. Ene. Pur. for Qlf. Cust > 5,000 kW	34	$13,028		$0	0.0%
17	Contract 1	--	$31,874	$12,297	$1,218	3.8%
19	Contract 2	--	$31,979	$13,966	$2,300	7.2%
20	Contract 3	--	$62,958		$0	0.0%
21	AGA/Revenue Credit	--	$4,797			
22	**Total Commercial & Industrial & OSPA**		$1,275,011	$325,692	$54,348	4.3%
	Public Street Lighting					
23	Security Area Lighting	7	$1,383	$219	$36	2.6%
24	Street Lighting - Company Owned	11	$3,759	$596	$98	2.6%
25	Street Lighting - Customer Owned	12	$1,385	$219	$36	2.6%
26	Metered Outdoor Lighting	15	$781	$324	$53	6.8%
27	Traffic Signal Systems	15	$803	$159	$26	3.3%
28	*Subtotal Public Street Lighting*		$8,111	$1,518	$250	3.1%
29	Security Area Lighting-Contracts (PTL)	--	$1	$0		
30	AGA/Revenue Credit	--	$5	$0		
31	**Total Public Street Lighting**		$8,116	$1,518	$250	3.1%
32	**Total Sales to Ultimate Customers**		$2,033,141	$467,286	$77,672	3.8%
				Target Rev	$77,672	month
				Avg %	3.8%	14
				Adj	98.03%	0.0

Rocky Mountain Power
Utah General Rate Case
EBA Base Detail and Allocator by Rate Schedule
Twelve Months Ending December 2021

Cost Item	FERC Account	Allocation Factor	COS Factor	Utah Allocated	Residential Sch 1	General Large Dist. Sch 6	General +1 MW Sch 8	Street & Area Lighting Sch. 7,11,12	General Trans Sch 9	Irrigation Sch 10	Traffic Signals Sch 15	Outdoor Lighting Sch 15	General Small Dist. Sch 23	Industrial Cust 1	Industrial Cust 2
Net Power Cost															
Sales for Resale	447	SG	F10	$98,192,924	35,166,810	26,661,879	7,833,066	105,411	17,495,514	824,420	27,714	35,720	6,199,437	2,180,498	1,662,454
Sales for Resale	447	SE	F30	$0	0	0	0	0	0	0	0	0	0	0	0
Fuel Expense	501	S	F30	$0	0	0	0	0	0	0	0	0	0	0	0
Fuel Expense	501	SE	F30	$263,295,693	78,558,168	71,691,371	23,236,442	590,046	55,104,669	2,668,320	90,063	184,879	16,265,837	6,955,042	7,950,855
Fuel Expense	503	SE	F30	$1,949,954	581,798	530,943	172,088	4,370	408,102	19,761	667	1,369	120,464	51,509	58,884
Fuel Expense	547	SE	F30	$127,675,262	38,093,805	34,764,012	11,267,631	286,121	26,720,920	1,293,900	43,673	89,650	7,887,501	3,372,584	3,855,466
Purchased Power	555	SE	F30	$21,901,944	6,534,769	5,963,563	1,932,896	49,082	4,583,817	221,961	7,492	15,379	1,353,055	578,547	661,383
Purchased Power	555	SG	F10	$242,063,016	86,692,439	65,726,273	19,309,900	259,858	43,129,553	2,032,343	68,320	88,055	15,282,714	5,375,315	4,098,245
Wheeling Expense	565	SG	F10	$17,631,213	6,314,442	4,787,323	1,406,481	18,927	3,141,440	148,030	4,976	6,414	1,113,151	391,523	298,505
Wheeling Expense	565	SE	F30	$46,251,367	13,799,780	12,593,536	4,081,788	103,649	9,679,863	468,726	15,821	32,476	2,857,309	1,221,745	1,396,673
Subtotal Net Power Cost				**$622,575,525**	**195,408,391**	**169,395,142**	**53,574,160**	**1,206,642**	**125,272,851**	**6,028,621**	**203,297**	**382,503**	**38,680,595**	**15,765,767**	**16,657,555**
Utah Situs Purchased Power Adj.	555	S	F30	$1,570,674	468,634	427,671	138,616	3,520	328,724	15,918	537	1,103	97,033	41,490	47,430
Total Net Power Cost				**$624,146,199**	**195,877,025**	**169,822,812**	**53,712,775**	**1,210,162**	**125,601,574**	**6,044,539**	**203,835**	**383,606**	**38,777,628**	**15,807,256**	**16,704,986**
Revenues from Transmission of Electricity by Others															
Other Electric Revenue	456.1	SG	F10	$44,320,155	15,872,819	12,034,051	3,535,516	47,578	7,896,739	372,109	12,509	16,122	2,798,165	984,185	750,362
Other Electric Revenue	456.1	SE	F30	$6,312,008	1,883,281	1,718,663	557,049	14,145	1,321,028	63,968	2,159	4,432	389,942	166,734	190,606
Total				**$50,632,163**	**17,756,100**	**13,752,714**	**4,092,565**	**61,723**	**9,217,768**	**436,077**	**14,668**	**20,554**	**3,188,107**	**1,150,919**	**940,968**
Production Tax Credits															
Production Tax Credits	40910	SG	F10	-$80,109,857	-$28,690,541	-$21,751,866	-$6,390,540	-$85,999	-$14,273,566	-$672,596	-$22,610	-$29,141	-$5,057,758	-$1,778,941	-$1,356,299
Tax Bump Up			F10	-$26,117,759	-$9,353,813	-$7,091,637	-$2,083,471	-$28,038	-$4,653,529	-$219,283	-$7,372	-$9,501	-$1,648,952	-$579,978	-$442,186
Total				**-$106,227,616**	**-38,044,354**	**-28,843,503**	**-8,474,011**	**-114,037**	**-18,927,095**	**-891,879**	**-29,982**	**-38,642**	**-6,706,709**	**-2,358,919**	**-1,798,485**
Total Base EBA Cost for Allocation				**$467,286,420**	**$140,076,571**	**$127,226,596**	**$41,146,199**	**$1,034,402**	**$97,456,712**	**$4,716,583**	**$159,185**	**$324,409**	**$28,882,811**	**$12,297,419**	**$13,965,532**
	2020 GRC Cost Factor		F10	1.00000	0.35814	0.27153	0.07977	0.00107	0.17817	0.00840	0.00028	0.00036	0.06314	0.02221	0.01693
	2020 GRC Cost Factor		F30	1.00000	0.29836	0.27228	0.08825	0.00224	0.20929	0.01013	0.00034	0.00070	0.06178	0.02642	0.03020

Rocky Mountain Power
Exhibit RMP___(RMM-2)
Docket No. 22-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Billing Determinants and Proposed EBA Rates

March 2022

Rocky Mountain Power - State of Utah
Blocking Based on Adjusted Actuals and Forecasted Loads
Base Period 12 Months Ending December 2019
Forecast Period 12 Months Ending December 2021

	Forecasted Units	Present Price		Revenue Dollars	Present EBA Price	Present EBA Dollars	Proposed EBA Price	Proposed EBA Dollars
Schedule No. 1- Residential Service								
Total Customer	9,344,849							
Customer Charge - 1 Phase	9,329,308							
Single Family	7,140,845	$10.00		$71,408,450				
Multi Family	2,188,463	$6.00		$13,130,778				
Customer Charge - 3 Phase	15,541							
Single Family	3,325	$20.00		$66,502				
Multi Family	12,216	$12.00		$146,592				
Aggregate Charge	0	$2.00		$0				
Non-Standard Meter Reading Fee	253	$22.00		$5,566				
On-Peak kWh (Jun - Sept)	0	4.3560	¢	$0				
Off-Peak kWh (Jun - Sept)	0	(1.6334)	¢	$0				
First 400 kWh (Jun-Sept)	1,080,475,945	9.0279	¢	$97,544,288	1.70%	$1,658,253	3.53%	$3,439,756
Next 600 kWh (Jun-Sept)	960,049,471	11.7210	¢	$112,527,398	1.70%	$1,912,966	3.53%	$3,968,113
All add'l kWh (Jun-Sept)	527,790,900	11.7210	¢	$61,862,371	1.70%	$1,051,660	3.53%	$2,181,486
First 400 kWh (Oct-May)	2,051,977,461	7.9893	¢	$163,938,635	1.70%	$2,786,957	3.53%	$5,781,055
All add'l kWh (Oct-May)	1,671,527,763	10.3725	¢	$173,379,217	1.70%	$2,947,447	3.53%	$6,113,963
Subscriber Solar kWh	15,864,580	11.9126	¢	$1,889,884				
Subscriber Solar kWh Adj	(316,213)							
Total	6,307,369,907			$695,899,681		$10,357,282		$21,484,373
Schedule No. 2 - Residential Service - Optional Time-of-Day								
Total Customer	4,350							
Customer Charge - 1 Phase	4,339							
Single Family	3,371	$10.00		$33,710				
Multi Family	968	$6.00		$5,808				
Customer Charge - 3 Phase	11							
Single Family	11	$20.00		$220				
Multi Family	0	$12.00		$0				
Aggregate Charge	0	$2.00		$0				
Non-Standard Meter Reading Fee	0	$22.00		$0				
On-Peak kWh (Jun - Sept)	258,230	4.3560	¢	$11,248				
Off-Peak kWh (Jun - Sept)	825,288	(1.6334)	¢	($13,480)				
First 400 kWh (Jun-Sept)	495,959	9.0279	¢	$44,775	1.70%	$761	3.53%	$1,579
Next 600 kWh (Jun-Sept)	407,470	11.7210	¢	$47,760	1.70%	$812	3.53%	$1,684
All add'l kWh (Jun-Sept)	186,496	11.7210	¢	$21,859	1.70%	$372	3.53%	$771
First 400 kWh (Oct-May)	919,695	7.9893	¢	$73,477	1.70%	$1,249	3.53%	$2,591
All add'l kWh (Oct-May)	734,416	10.3725	¢	$76,177	1.70%	$1,295	3.53%	$2,686
Subscriber Solar kWh	0	11.9126	¢	$0				
Subscriber Solar kWh Adj	0							
Total	2,744,036			$301,554		$4,489		$9,311

Schedule No. 2E - Electric Vehicle Time-of-Use Pilot Option

Total Customer	3,114							
Customer Charge - 1 Phase	3,114							
Single Family	2,923	$10.00		$29,230				
Multi Family	191	$6.00		$1,146				
Customer Charge - 3 Phase	0							
Single Family		$20.00		$0				
Multi Family		$12.00		$0				
Aggregate Charge	0	$2.00		$0				
Non-Standard Meter Reading Fee	0	$22.00		$0				
Rate Option 1								
On-Peak kWh	206,699	21.0339	¢	$43,477	1.70%	$739	3.53%	$1,533
Off-Peak kWh	963,611	6.4097	¢	$61,765	1.70%	$1,050	3.53%	$2,178
Rate Option 2								
On-Peak kWh	347,186	32.4593	¢	$112,694	1.70%	$1,916	3.53%	$3,974
Off-Peak kWh	2,130,652	3.2108	¢	$68,411	1.70%	$1,163	3.53%	$2,412
Subscriber Solar kWh	0	11.9126	¢	$0				
Subscriber Solar kWh Adj	0							
Total	3,648,148			$316,723		$4,868		$10,098

Schedule No. 3- Residential Service - Low Income Lifeline Program

Total Customer	216,323							
Customer Charge - 1 Phase	216,152							
Single Family	113,309	$10.00		$1,133,090				
Multi Family	102,843	$6.00		$617,058				
Customer Charge - 3 Phase	171							
Single Family	27	$20.00		$540				
Multi Family	144	$12.00		$1,728				
Aggregate Charge	0	$2.00		$0				
Non-Standard Meter Reading Fee	0	$22.00		$0				
On-Peak kWh (Jun - Sept)	5,354	4.3560	¢	$233				
Off-Peak kWh (Jun - Sept)	15,633	(1.6334)	¢	($255)				
First 400 kWh (Jun-Sept)	26,384,768	9.0279	¢	$2,381,990	1.70%	$40,494	3.53%	$83,997
Next 600 kWh (Jun-Sept)	17,765,859	11.7210	¢	$2,082,336	1.70%	$35,400	3.53%	$73,431
All add'l kWh (Jun-Sept)	5,668,613	11.7210	¢	$664,418	1.70%	$11,295	3.53%	$23,430
First 400 kWh (Oct-May)	51,185,664	7.9893	¢	$4,089,376	1.70%	$69,519	3.53%	$144,206
All add'l kWh (Oct-May)	32,983,258	10.3725	¢	$3,421,188	1.70%	$58,160	3.53%	$120,643
Subscriber Solar kWh	108,762	11.9126	¢	$12,956				
Subscriber Solar kWh Adj	(3,852)							
Total	134,093,072			$14,404,658		$214,868		$445,707

Schedule No. 135 - Residential Service - Net Metering

Total Customer	418,416							
Customer Charge - 1 Phase	418,038							
Single Family	405,641	$10.00		$4,056,410				
Multi Family	12,397	$6.00		$74,382				
Customer Charge - 3 Phase	378							
Single Family	112	$20.00		$2,240				
Multi Family	266	$12.00		$3,192				
Aggregate Charge	0	$2.00		$0				
Non-Standard Meter Reading Fee	14	$22.00		$308				
On-Peak kWh (Jun - Sept)	7,090	4.3560	¢	$309				
Off-Peak kWh (Jun - Sept)	44,469	(1.6334)	¢	($726)				
First 400 kWh (Jun-Sept)	21,966,174	9.0279	¢	$1,983,084	1.70%	$33,712	3.53%	$69,931
Next 600 kWh (Jun-Sept)	14,447,176	11.7210	¢	$1,693,353	1.70%	$28,787	3.53%	$59,714
All add'l kWh (Jun-Sept)	7,916,923	11.7210	¢	$927,943	1.70%	$15,775	3.53%	$32,723
First 400 kWh (Oct-May)	50,047,131	7.9893	¢	$3,998,415	1.70%	$67,973	3.53%	$140,998
All add'l kWh (Oct-May)	47,956,842	10.3725	¢	$4,974,323	1.70%	$84,563	3.53%	$175,412
Subscriber Solar kWh	0	11.9126	¢	$0				
Subscriber Solar kWh Adj	0							
Total	142,334,246			$17,713,233		$230,811		$478,777

Schedule No. 136 - Residential Service - Net Metering

Total Customer	307,354							
Customer Charge - 1 Phase	307,354							
Single Family	303,609	$10.00		$3,036,090				
Multi Family	3,745	$6.00		$22,470				
Customer Charge - 3 Phase	0							
Single Family		$20.00		$0				
Multi Family		$12.00		$0				
Aggregate Charge	1,646	$2.00		$3,292				
Non-Standard Meter Reading Fee	0	$22.00		$0				
On-Peak kWh (Jun - Sept)	5,690	4.3560	¢	$248				
Off-Peak kWh (Jun - Sept)	35,358	(1.6334)	¢	($578)				
First 400 kWh (Jun-Sept)	38,703,048	9.0279	¢	$3,494,072	1.70%	$59,399	3.53%	$123,213
Next 600 kWh (Jun-Sept)	26,842,157	11.7210	¢	$3,146,169	1.70%	$53,485	3.53%	$110,945
All add'l kWh (Jun-Sept)	7,600,557	11.7210	¢	$890,861	1.70%	$15,145	3.53%	$31,415
First 400 kWh (Oct-May)	68,555,364	7.9893	¢	$5,477,094	1.70%	$93,111	3.53%	$193,142
All add'l kWh (Oct-May)	51,108,843	10.3725	¢	$5,301,265	1.70%	$90,122	3.53%	$186,941
Subscriber Solar kWh	0	11.9126	¢	$0				
Subscriber Solar kWh Adj	0							
Total	192,809,969			$21,370,983		$311,261		$645,656

Schedule No. 6 - Composite

Customer Charge	157,116	$53.00		$8,327,148				
Seasonal Service	0	$636.00		$0				
Minimum Charge	14	$53.00		$742				
Facilities kW	15,576,842	$3.99		$62,151,600				
All kW (Jun - Sept)	6,921,590	$13.27		$91,849,499	2.25%	$2,066,614	4.68%	$4,296,934
All kW (Oct - May)	8,655,252	$11.74		$101,612,658	2.25%	$2,286,285	4.68%	$4,753,678
kWh (Jun-Sept)	2,063,156,225	3.8878	¢	$80,211,388	2.25%	$1,804,756	4.68%	$3,752,476
kWh (Oct-May)	3,526,754,594	3.4405	¢	$121,337,992	2.25%	$2,730,105	4.68%	$5,676,475
Voltage Discount	569,738	($0.96)		($546,948)				
Subscriber Solar kWh	1,977,670	7.1250	¢	$140,909				
Subscriber Solar kWh Adj	25,489							
Total	5,591,913,978			$465,084,988		$8,887,760		$18,479,564

Schedule No. 6-135 - Net Metering - Composite

Customer Charge	4,434	$53.00		$235,002				
Seasonal Service	0	$636.00		$0				
Minimum Charge	0	$53.00		$0				
Facilities kW	505,379	$3.99		$2,016,462				
All kW (Jun - Sept)	206,980	$13.27		$2,746,625	2.25%	$61,799	4.68%	$128,494
All kW (Oct - May)	298,398	$11.74		$3,503,193	2.25%	$78,822	4.68%	$163,888
kWh (Jun-Sept)	60,590,666	3.8878	¢	$2,355,644	2.25%	$53,002	4.68%	$110,203
kWh (Oct-May)	109,661,558	3.4405	¢	$3,772,906	2.25%	$84,890	4.68%	$176,505
Voltage Discount	26,614	($0.96)		($25,549)				
Total	170,252,223			$14,604,283		$278,513		$579,089

Schedule No. 6-136 - Net Metering - Composite

Customer Charge	611	$53.00		$32,383				
Seasonal Service	0	$636.00		$0				
Aggregate Charge	59	$2.00		$118				
Facilities kW	94,165	$3.99		$375,718				
All kW (Jun - Sept)	40,576	$13.27		$538,444	2.25%	$12,115	4.68%	$25,190
All kW (Oct - May)	53,589	$11.74		$629,135	2.25%	$14,156	4.68%	$29,432
kWh (Jun-Sept)	8,593,599	3.8878	¢	$334,102	2.25%	$7,517	4.68%	$15,630
kWh (Oct-May)	15,566,358	3.4405	¢	$535,561	2.25%	$12,050	4.68%	$25,055
Voltage Discount	0	($0.96)		$0				
Total	24,159,957			$2,445,461		$45,838		$95,307

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

Customer Charge	192	$53.00	$10,176				
Seasonal Service	0	$636.00	$0				
Facilities kW	14,844	$3.99	$59,228				
All on-peak kW (Jun - Sept)	4,915	$13.27	$65,222	2.25%	$1,467	4.68%	$3,051
All on-peak kW (Oct - May)	6,971	$11.74	$81,840	2.25%	$1,841	4.68%	$3,829
kWh (Jun-Sept)	1,281,170	3.8878 ¢	$49,809	2.25%	$1,121	4.68%	$2,330
kWh (Oct-May)	2,099,521	3.4405 ¢	$72,234	2.25%	$1,625	4.68%	$3,379
Voltage Discount	0	($0.96)	$0				
Total	3,380,691		$338,509		$6,055		$12,589

Schedule 6 moving to 6A - Composite

Customer Charge	16,185	$53.00	$857,783				
All kWh under 50 kWh/kW (Jun-Sept)	22,837,906	22.1562 ¢	$5,060,012	3.42%	$173,052	4.35%	$219,947
All additional kWh (Jun-Sept)	52,553,411	4.3099 ¢	$2,264,999	3.42%	$77,463	4.35%	$98,454
All kWh under 50 kWh/kW (Oct-May)	39,702,141	19.6073 ¢	$7,784,518	3.42%	$266,231	4.35%	$338,375
All additional (Oct-May)	93,250,801	3.8141 ¢	$3,556,679	3.42%	$121,638	4.35%	$154,601
On-Pk kWh (Jun-Sept)	41,868,606	6.0000 ¢	$2,512,116	3.42%	$85,914	4.35%	$109,196
Off-Pk kWh (Jun-Sept)	33,522,711	(2.3358) ¢	($783,023)	3.42%	($26,779)	4.35%	($34,036)
On-Pk kWh (Oct-May)	73,835,484	5.3097 ¢	$3,920,443	3.42%	$134,079	4.35%	$170,413
Off-Pk kWh (Oct-May)	59,117,459	(2.0671) ¢	($1,222,017)	3.42%	($41,793)	4.35%	($53,118)
Voltage Discount	56,872	($0.61)	($34,692)				
Subscriber Solar kWh	758,838	7.1250 ¢	$54,067				
Schedule 6A	209,103,098		$23,970,885		$789,805		$1,003,831

Customer Charge	16,185	$53.00	$857,783				
Seasonal Service	0	$636.00	$0				
Minimum Charge	0	$53.00	$0				
Facilities kW	1,281,154	$3.99	$5,111,804				
All kW (Jun - Sept)	467,710	$13.27	$6,206,512	2.25%	$139,647	4.68%	$290,355
All kW (Oct - May)	813,444	$11.74	$9,549,833	2.25%	$214,871	4.68%	$446,764
kWh (Jun-Sept)	75,391,317	3.8878 ¢	$2,931,064	2.25%	$65,949	4.68%	$137,122
kWh (Oct-May)	132,952,943	3.4405 ¢	$4,574,246	2.25%	$102,921	4.68%	$213,994
Voltage Discount	56,872	($0.96)	($54,597)				
Subscriber Solar kWh	758,838	7.1250 ¢	$54,067				
Total	209,103,098		$29,230,712		$523,387		$1,088,235

Schedule 6-135 moving to 6A - Net Metering - Composite

Customer Charge	602	$53.00		$31,904				
All kWh under 50 kWh/kW (Jun-Sept)	617,625	22.1562	¢	$136,842	3.42%	$4,680	4.35%	$5,948
All additional kWh (Jun-Sept)	1,470,157	4.3099	¢	$63,362	3.42%	$2,167	4.35%	$2,754
All kWh under 50 kWh/kW (Oct-May)	1,069,623	19.6073	¢	$209,724	3.42%	$7,173	4.35%	$9,116
All additional (Oct-May)	2,803,066	3.8141	¢	$106,912	3.42%	$3,656	4.35%	$4,647
On-Pk kWh (Jun-Sept)	1,159,451	6.0000	¢	$69,567	3.42%	$2,379	4.35%	$3,024
Off-Pk kWh (Jun-Sept)	928,331	(2.3358)	¢	($21,684)	3.42%	($742)	4.35%	($943)
On-Pk kWh (Oct-May)	2,150,700	5.3097	¢	$114,196	3.42%	$3,906	4.35%	$4,964
Off-Pk kWh (Oct-May)	1,721,989	(2.0671)	¢	($35,595)	3.42%	($1,217)	4.35%	($1,547)
Voltage Discount	0	($0.61)		$0				
Subscriber Solar kWh	0	7.1250	¢	$0				
Schedule 6A	5,960,471			$675,228		$22,002		$27,964
Customer Charge	602	$53.00		$31,904				
Seasonal Service	0	$636.00		$0				
Minimum Charge	0	$53.00		$0				
Facilities kW	42,952	$3.99		$171,378				
All kW (Jun - Sept)	16,126	$13.27		$213,992	2.25%	$4,815	4.68%	$10,011
All kW (Oct - May)	26,826	$11.74		$314,937	2.25%	$7,086	4.68%	$14,733
kWh (Jun-Sept)	2,218,023	3.8878	¢	$86,232	2.25%	$1,940	4.68%	$4,034
kWh (Oct-May)	4,105,852	3.4405	¢	$141,262	2.25%	$3,178	4.68%	$6,609
Voltage Discount	0	($0.96)		$0				
Total	6,323,875			$959,705		$17,020		$35,387

Schedule 6B moving to 6A - Composite

Customer Charge	69	$53.00		$3,665				
All kWh under 50 kWh/kW (Jun-Sept)	23,181	22.1562	¢	$5,136	3.42%	$176	4.35%	$223
All additional kWh (Jun-Sept)	32,182	4.3099	¢	$1,387	3.42%	$47	4.35%	$60
All kWh under 50 kWh/kW (Oct-May)	59,234	19.6073	¢	$11,614	3.42%	$397	4.35%	$505
All additional (Oct-May)	26,202	3.8141	¢	$999	3.42%	$34	4.35%	$43
On-Pk kWh (Jun-Sept)	30,746	6.0000	¢	$1,845	3.42%	$63	4.35%	$80
Off-Pk kWh (Jun-Sept)	24,617	(2.3358)	¢	($575)	3.42%	($20)	4.35%	($25)
On-Pk kWh (Oct-May)	47,447	5.3097	¢	$2,519	3.42%	$86	4.35%	$109
Off-Pk kWh (Oct-May)	37,989	(2.0671)	¢	($785)	3.42%	($27)	4.35%	($34)
Voltage Discount	0	($0.61)		$0				
Subscriber Solar kWh	0	7.1250	¢	$0				
Schedule 6A	140,800			$25,805		$757		$962
Customer Charge	69	$53.00		$3,665				
Seasonal Service	0	$636.00		$0				
Facilities kW	2,794	$3.99		$11,148				
All on-peak kW (Jun - Sept)	832	$13.27		$11,041	2.25%	$248	4.68%	$517
All on-peak kW (Oct - May)	1,962	$11.74		$23,034	2.25%	$518	4.68%	$1,078
kWh (Jun-Sept)	55,363	3.8878	¢	$2,152	2.25%	$48	4.68%	$101
kWh (Oct-May)	85,437	3.4405	¢	$2,939	2.25%	$66	4.68%	$137
Voltage Discount	0	($0.96)		$0				
Total	140,800			$53,979		$881		$1,832

Schedule No. 6A - Energy Time-of-Day Option - Composite

All kWh under 50 kWh/kW (Jun-Sept)	44,585,441	22.1562 ¢	$9,878,440	3.42%	$337,843	4.35%	$429,393
All additional kWh (Jun-Sept)	80,754,202	4.3099 ¢	$3,480,425	3.42%	$119,031	4.35%	$151,286
All kWh under 50 kWh/kW (Oct-May)	73,546,803	19.6073 ¢	$14,420,542	3.42%	$493,183	4.35%	$626,828
All additional (Oct-May)	153,778,261	3.8141 ¢	$5,865,257	3.42%	$200,592	4.35%	$254,949
On-Pk kWh (Jun-Sept)	65,422,495	6.0000 ¢	$3,925,350	3.42%	$134,247	4.35%	$170,626
Off-Pk kWh (Jun-Sept)	59,917,149	(2.3358) ¢	($1,399,545)	3.42%	($47,864)	4.35%	($60,835)
On-Pk kWh (Oct-May)	124,025,012	5.3097 ¢	$6,585,356	3.42%	$225,219	4.35%	$286,250
Off-Pk kWh (Oct-May)	103,300,051	(2.0671) ¢	($2,135,315)	3.42%	($73,028)	4.35%	($92,817)
Customer Charge	31,870	$53.00	$1,689,110				
Voltage Discount	203,454	($0.61)	($124,107)				
Subscriber Solar kWh	29,568,815	7.1250 ¢	$2,106,778				
Subscriber Solar kWh Adj	(1,649,518)						
Total	380,584,004		$44,292,291		$1,389,221		$1,765,680

Schedule No. 6A-135 - Composite

All kWh under 50 kWh/kW (Jun-Sept)	1,790,597	22.1562 ¢	$396,728	3.42%	$13,568	4.35%	$17,245
All additional kWh (Jun-Sept)	3,521,773	4.3099 ¢	$151,785	3.42%	$5,191	4.35%	$6,598
All kWh under 50 kWh/kW (Oct-May)	5,330,608	19.6073 ¢	$1,045,188	3.42%	$35,745	4.35%	$45,432
All additional (Oct-May)	12,790,668	3.8141 ¢	$487,849	3.42%	$16,684	4.35%	$21,206
On-Pk kWh (Jun-Sept)	3,345,042	6.0000 ¢	$200,703	3.42%	$6,864	4.35%	$8,724
Off-Pk kWh (Jun-Sept)	1,967,328	(2.3358) ¢	($45,953)	3.42%	($1,572)	4.35%	($1,997)
On-Pk kWh (Oct-May)	10,972,800	5.3097 ¢	$582,623	3.42%	$19,926	4.35%	$25,325
Off-Pk kWh (Oct-May)	7,148,476	(2.0671) ¢	($147,766)	3.42%	($5,054)	4.35%	($6,423)
Customer Charge	1,797	$53.00	$95,241				
Voltage Discount	16,106	($0.61)	($9,825)				
Total	23,433,646		$2,756,573		$91,354		$116,109

Schedule No. 7 - Security Area Lighting - Composite

Level 1 (0-5,500 LED Equivalent Lumens	80,037	$9.10	$728,334	1.06%	$7,720	2.61%	$19,012
Level 2 (5,501-12,000 LED Equivalent Lu	23,298	$10.61	$247,190	1.06%	$2,620	2.61%	$6,452
Level 3 (12,001 and Greater LED Equival	31,462	$12.96	$407,743	1.06%	$4,322	2.61%	$10,643
Customers	6,491						
Total (kWh)	10,497,984		$1,383,267		$14,663		$36,108

Schedule No. 8 - Composite

Customer Charge	2,823	$71.00	$200,433				
Facilities kW	4,249,794	$4.81	$20,441,509				
On-Peak kW (Jun - Sept)	1,442,193	$15.73	$22,685,696	2.45%	$555,800	5.27%	$1,195,809
On-Peak kW (Oct - May)	2,597,774	$13.92	$36,161,014	2.45%	$885,945	5.27%	$1,906,121
On-Peak kWh (Jun - Sept)	186,186,148	5.8282 ¢	$10,851,301	2.45%	$265,857	5.27%	$571,994
On-Peak kWh (Oct - May)	270,238,556	5.1577 ¢	$13,938,094	2.45%	$341,483	5.27%	$734,705
Off-Peak kWh (Jun - Sept)	524,787,623	2.9624 ¢	$15,546,309	2.45%	$380,885	5.27%	$819,478
Off-Peak kWh (Oct - May)	976,265,495	2.6216 ¢	$25,593,776	2.45%	$627,048	5.27%	$1,349,100
Voltage Discount	1,886,120	($1.13)	($2,131,316)				
Total	1,957,477,822		$143,286,816		$3,057,017		$6,577,208

Schedule No. 9 - Composite

Customer Charge	1,872	$266.00	$497,952				
Facilities kW	8,792,631	$2.28	$20,047,199				
On-Peak kW (Jun - Sept)	2,857,444	$14.33	$40,947,173	2.95%	$1,207,942	6.59%	$2,697,667
On-Peak kW (Oct - May)	5,600,405	$12.68	$71,013,135	2.95%	$2,094,887	6.59%	$4,678,463
On-Peak kWh (Jun - Sept)	337,257,779	5.1477 ¢	$17,361,019	2.95%	$512,150	6.59%	$1,143,773
On-Peak kWh (Oct - May)	653,220,065	4.5555 ¢	$29,757,440	2.95%	$877,844	6.59%	$1,960,469
Off-Peak kWh (Jun - Sept)	1,318,310,247	2.6165 ¢	$34,493,588	2.95%	$1,017,561	6.59%	$2,272,494
Off-Peak kWh (Oct - May)	2,538,543,863	2.3155 ¢	$58,779,983	2.95%	$1,734,009	6.59%	$3,872,522
Total	4,847,331,954		$272,897,489		$7,444,394		$16,625,388

Schedule No. 9A - Energy TOD - Composite

Customer Charge	108	$266.00	$28,728				
Facilities Charge per kW	243,087	$2.28	$554,238				
On-Peak kW (Jun - Sept)	76,062	$4.73	$359,773	3.27%	$11,765	7.21%	$25,956
On-Peak kW (Oct - May)	169,650	$4.18	$709,137	3.27%	$23,189	7.21%	$51,160
On-Peak kWh (Jun - Sept)	6,818,306	5.1477 ¢	$350,986	3.27%	$11,477	7.21%	$25,322
On-Peak kWh (Oct - May)	7,138,084	4.5555 ¢	$325,175	3.27%	$10,633	7.21%	$23,459
Off-Peak kWh (Jun - Sept)	5,708,900	2.6165 ¢	$149,373	3.27%	$4,884	7.21%	$10,776
Off-Peak kWh (Oct - May)	22,274,997	2.3155 ¢	$515,778	3.27%	$16,866	7.21%	$37,210
Total	41,940,288		$2,993,188		$78,814		$173,883

Schedule No. 10 - Irrigation									
Annual Cust. Serv. Chg. - Primary	10	$122.00		$1,220					
Annual Cust. Serv. Chg. - Secondary	3,273	$37.00		$121,101					
Monthly Cust. Serv. Chg.	14,850	$14.00		$207,900					
All On-Season kW	425,282	$7.14		$3,036,513	2.18%	$66,196	4.43%	$134,479	
Voltage Discount	4,699	($2.05)		($9,633)					
First 30,000 kWh	90,734,008	7.1126	¢	$6,453,547	2.18%	$140,687	4.43%	$285,811	
All add'l kWh	54,847,557	5.2573	¢	$2,883,501	2.18%	$62,860	4.43%	$127,703	
Total On Season	145,581,565			$12,694,149					
Post Season									
Customer Charge	7,027	$14.00		$98,378					
kWh	51,252,091	4.8789	¢	$2,500,538	2.18%	$54,512	4.43%	$110,743	
Total Post Season	51,252,091			$2,598,916					
TOTAL RATE 10	196,833,656			$15,293,065		$324,255		$658,736	
Schedule No. 10-135 - Irrigation									
Annual Cust. Serv. Chg. - Primary	1	$122.00		$122					
Annual Cust. Serv. Chg. - Secondary	55	$37.00		$2,035					
Monthly Cust. Serv. Chg.	285	$14.00		$3,990					
All On-Season kW	26,155	$7.14		$186,747	2.18%	$4,071	4.43%	$8,271	
Voltage Discount	10	($2.05)		($21)					
First 30,000 kWh	3,703,888	7.1126	¢	$263,443	2.18%	$5,743	4.43%	$11,667	
All add'l kWh	3,271,622	5.2573	¢	$171,999	2.18%	$3,750	4.43%	$7,617	
On-Peak kWh	132,217	14.0520	¢	$18,579	2.18%	$405	4.43%	$823	
Off-Peak kWh	494,707	4.0492	¢	$20,032	2.18%	$437	4.43%	$887	
Total On Season	7,602,434			$666,926					
Post Season									
Customer Charge	123	$14.00		$17					
kWh	1,697,996	4.8789	¢	$82,844	2.18%	$1,806	4.43%	$3,669	
Total Post Season	1,697,996			$82,861					
TOTAL RATE 10-135	9,300,430			$749,787		$16,211		$32,934	
Schedule No. 10-TOD									
Annual Cust. Serv. Chg. - Primary	3	$122.00		$366					
Annual Cust. Serv. Chg. - Secondary	266	$37.00		$9,842					
Monthly Cust. Serv. Chg.	1,196	$14.00		$16,744					
All On-Season kW	63,002	$7.14		$449,834	2.18%	$9,806	4.43%	$19,922	
Voltage Discount kW	2,363	($2.05)		($4,844)					
On-Peak kWh	4,395,923	14.0520	¢	$617,715	2.18%	$13,466	4.43%	$27,357	
Off-Peak kWh	13,428,677	4.0492	¢	$543,754	2.18%	$11,854	4.43%	$24,081	
Total On Season	17,824,600			$1,633,411					
Post Season									
Customer Charge	605	$14.00		$85					
kWh	6,433,787	4.8789	¢	$313,898	2.18%	$6,843	4.43%	$13,902	
Total Post Season	6,433,787			$313,983					
TOTAL RATE 10-TOD	24,258,387			$1,947,394		$41,969		$85,262	

Schedule No. 11 - Street Lighting - Company-Owned System								
Functional Lighting								
Level 1 (0-3,500 LED Equivalent Lumens	32,060	$11.82		$378,953	1.06%	$4,017	2.61%	$9,892
Level 2 (3,501-5,500 LED Equivalent Lur	197,233	$12.74		$2,512,752	1.06%	$26,635	2.61%	$65,591
Level 3 (5,501-8,000 LED Equivalent Lur	20,644	$13.19		$272,290	1.06%	$2,886	2.61%	$7,108
Level 4 (8,001-12,000 LED Equivalent Lu	574	$13.71		$7,871	1.06%	$83	2.61%	$205
Level 5 (12,001-15,500 LED Equivalent I	22,536	$14.60		$329,020	1.06%	$3,488	2.61%	$8,588
Level 6 (15,501 and Greater LED Equival	7,800	$17.75		$138,445	1.06%	$1,468	2.61%	$3,614
Decorative Series								
Level 3 (5,501-8,000 LED Equivalent Lur	5,104	$23.15		$118,165	1.06%	$1,253	2.61%	$3,085
Customer-Funded Conversion								
Level 1 (0-3,500 LED Equivalent Lumens	0	$6.04		$0	1.06%	$0	2.61%	$0
Level 2 (3,501-5,500 LED Equivalent Lur	276	$6.57		$1,813	1.06%	$19	2.61%	$47
Level 3 (5,501-8,000 LED Equivalent Lur	0	$6.99		$0	1.06%	$0	2.61%	$0
Level 4 (8,001-12,000 LED Equivalent Lu	0	$7.46		$0	1.06%	$0	2.61%	$0
Level 5 (12,001-15,500 LED Equivalent I	12	$8.00		$96	1.06%	$1	2.61%	$3
Level 6 (15,501 and Greater LED Equival	0	$9.72		$0	1.06%	$0	2.61%	$0
Customer-Funded Conversion Decorative Series								
Level 3 (5,501-8,000 LED Equivalent Lur	0	$5.52		$0	1.06%	$0	2.61%	$0
Customers	715							
Total	13,572,508			$3,759,405		$39,850		$98,133
Schedule No. 12 - Street Lighting - Customer-Owned System								
1. Energy Only, No Maintenance								
High Pressures Sodium Vapor Lamps								
5,600 Lumen	51,176	$1.33		$68,064	1.06%	$721	2.61%	$1,777
9,500 Lumen	80,459	$1.81		$145,631	1.06%	$1,544	2.61%	$3,801
16,000 Lumen	67,482	$2.65		$178,827	1.06%	$1,896	2.61%	$4,668
27,500 Lumen	17,154	$4.73		$81,138	1.06%	$860	2.61%	$2,118
50,000 Lumen	10,092	$7.27		$73,369	1.06%	$778	2.61%	$1,915
Metal Halide Lamps								
9,000 Lumen	4,369	$1.85		$8,083	1.06%	$86	2.61%	$211
12,000 Lumen	9,335	$3.24		$30,245	1.06%	$321	2.61%	$790
19,500 Lumen	10,137	$4.48		$45,414	1.06%	$481	2.61%	$1,185
32,000 Lumen	6,173	$7.09		$43,767	1.06%	$464	2.61%	$1,142
Non-listed Luminaries kWh	9,608,182	4.5465	¢	$436,836	1.06%	$4,630	2.61%	$11,403

2a - Partial Maintenance (No New Service)

Incandescent Lamps							
2,500 Lumen or Less	46	$6.50	$299	1.06%	$3	2.61%	$8
4,000 Lumen	23	$8.84	$203	1.06%	$2	2.61%	$5
Mercury Vapor Lamps							
4,000 Lumen	0	$3.37	$0	1.06%	$0	2.61%	$0
7,000 Lumen	404	$5.08	$2,052	1.06%	$22	2.61%	$54
20,000 Lumen	53	$9.67	$513	1.06%	$5	2.61%	$13
54,000 Lumen	0	$20.59	$0	1.06%	$0	2.61%	$0
High Pressure Sodium Vapor Lamps							
5,600 Lumen	1,416	$2.96	$4,191	1.06%	$44	2.61%	$109
9,500 Lumen	6,699	$3.90	$26,126	1.06%	$277	2.61%	$682
9,500 Lumen - Decorative	3,869	$5.05	$19,538	1.06%	$207	2.61%	$510
16,000 Lumen	586	$4.73	$2,772	1.06%	$29	2.61%	$72
16,000 Lumen - Decorative	269	$6.00	$1,614	1.06%	$17	2.61%	$42
22,000 Lumen	0	$5.99	$0	1.06%	$0	2.61%	$0
27,500 Lumen	1,740	$6.96	$12,110	1.06%	$128	2.61%	$316
27,500 Lumen - Decorative	77	$8.65	$666	1.06%	$7	2.61%	$17
50,000 Lumen	4,562	$10.15	$46,304	1.06%	$491	2.61%	$1,209
50,000 Lumen - Decorative	76	$11.29	$858	1.06%	$9	2.61%	$22
Metal Halide Lamps							
9,000 Lumen - Decorative	587	$6.67	$3,915	1.06%	$42	2.61%	$102
12,000 Lumen	847	$9.84	$8,334	1.06%	$88	2.61%	$218
12,000 Lumen - Decorative	130	$8.04	$1,045	1.06%	$11	2.61%	$27
19,500 Lumen	244	$9.94	$2,425	1.06%	$26	2.61%	$63
19,500 Lumen - Decorative	3,676	$10.25	$37,679	1.06%	$399	2.61%	$984
32,000 Lumen	122	$10.58	$1,291	1.06%	$14	2.61%	$34
32,000 Lumen - Decorative	352	$11.45	$4,030	1.06%	$43	2.61%	$105
Fluorescent Lamps							
1,000 Lumen	0	$2.72	$0	1.06%	$0	2.61%	$0
21,800 Lumen	53	$10.10	$535	1.06%	$6	2.61%	$14

2b - Full Maintenance (No New Service)							
Incandescent Lamps							
6,000 Lumen	37	$12.86	$476	1.06%	$5	2.61%	$12
10,000 Lumen	12	$16.97	$204	1.06%	$2	2.61%	$5
Mercury Vapor Lamps							
7,000 Lumen	25	$5.82	$146	1.06%	$2	2.61%	$4
20,000 Lumen	0	$11.10	$0	1.06%	$0	2.61%	$0
54,000 Lumen	0	$23.56	$0	1.06%	$0	2.61%	$0
Sodium Vapor Lamps							
5,600 Lumen	4,183	$3.39	$14,180	1.06%	$150	2.61%	$370
9,500 Lumen	7,164	$4.47	$32,023	1.06%	$339	2.61%	$836
16,000 Lumen	597	$5.42	$3,236	1.06%	$34	2.61%	$84
22,000 Lumen	0	$6.85	$0	1.06%	$0	2.61%	$0
27,500 Lumen	1,267	$7.97	$10,098	1.06%	$107	2.61%	$264
50,000 Lumen	1,657	$11.62	$19,254	1.06%	$204	2.61%	$503
Metal Halide Lamps							
12,000 Lumen	35	$11.30	$396	1.06%	$4	2.61%	$10
19,500 Lumen	748	$11.41	$8,535	1.06%	$90	2.61%	$223
32,000 Lumen	697	$12.13	$8,455	1.06%	$90	2.61%	$221
107,000 Lumen	0	$23.97	$0	1.06%	$0	2.61%	$0
Customers	1,229						
Total	26,868,874		$1,384,878.49		$14,680		$36,150
Schedule 15.1 - Metered Outdoor Nighttime Lighting - Composite							
Annual Facility Charge	21,139	$7.00	$147,973				
Annual Customer Charge	638	$49.02	$31,275				
Annual Minimum Charge	0	$84.02	$0				
Monthly Customer Charge	7,644	$4.19	$32,028				
All kWh	15,963,151	3.5697 ¢	$569,837	2.84%	$16,183	9.38%	$53,438
Total	15,963,151		$781,113		$16,183		$53,438
Schedule 15.2 - Traffic Signal Systems - Composite							
Customer Charge	32,811	$5.50	$180,461				
All kWh	7,776,370	8.0005 ¢	$622,149	1.92%	$11,945	4.21%	$26,222
Total	7,776,370		$802,610		$11,945		$26,222

Schedule No. 21 - Electric Furnace Operations - Limited Service - Industrial

Schedule 6A								
Customer Charge	15	$53.00		$795				
Voltage Discount	0	($0.61)		$0				
All kWh under 50 kWh/kW (Jun-Sept)	82,148	22.1562	¢	$18,201	3.42%	$622	4.35%	$791
All additional kWh (Jun-Sept)	0	4.3099	¢	$0	3.42%	$0	4.35%	$0
All kWh under 50 kWh/kW (Oct-May)	156,310	19.6073	¢	$30,648	3.42%	$1,048	4.35%	$1,332
All additional (Oct-May)	0	3.8141	¢	$0	3.42%	$0	4.35%	$0
On-Pk kWh (Jun-Sept)	45,621	6.0000	¢	$2,737	3.42%	$94	4.35%	$119
Off-Pk kWh (Jun-Sept)	36,527	(2.3358)	¢	($853)	3.42%	($29)	4.35%	($37)
On-Pk kWh (Oct-May)	86,807	5.3097	¢	$4,609	3.42%	$158	4.35%	$200
Off-Pk kWh (Oct-May)	69,503	(2.0671)	¢	($1,437)	3.42%	($49)	4.35%	($62)
	238,458			$54,700		$1,844		$2,343
Schedule 9								
Customer Charge	21	$266.00		$5,586				
Facilities kW	25,596	$2.28		$58,358				
On-Peak kW (Jun - Sept)	8,668	$14.33		$124,208	2.95%	$3,664	6.59%	$8,183
On-Peak kW (Oct - May)	16,941	$12.68		$214,810	2.95%	$6,337	6.59%	$14,152
On-Peak kWh (Jun - Sept)	91,666	5.1477	¢	$4,719	2.95%	$139	6.59%	$311
On-Peak kWh (Oct - May)	244,288	4.5555	¢	$11,129	2.95%	$328	6.59%	$733
Off-Peak kWh (Jun - Sept)	362,605	2.6165	¢	$9,488	2.95%	$280	6.59%	$625
Off-Peak kWh (Oct - May)	900,095	2.3155	¢	$20,842	2.95%	$615	6.59%	$1,373
	1,598,654			$449,140		$11,363		$25,377
Total	1,837,112			$503,840		$13,207		$27,720

Schedule No.22 - Indoor Agricultural Lighting Service – 1,000 kW and Over								
Customer Service Charge								
Secondary		$73.00						
Primary		$73.00						
Transmission		$269.00						
Facilities Charge All kW								
Secondary		$1.42						
Primary		$1.42						
Transmission		$1.42						
Power Charge								
Secondary								
Summer-On Peak kW		$8.46						
Winter-On Peak kW		$6.08						
Primary								
Summer-On Peak kW		$8.35						
Winter-On Peak kW		$5.82						
Transmission								
Summer-On Peak kW		$8.12						
Winter-On Peak kW		$5.51						
Energy Charge								
Secondary								
Summer-On Peak kWh		9.5743	¢					
Summer-Off Peak kWh		5.2656	¢					
Winter-On Peak kWh		4.2635	¢					
Winter-Off Peak kWh		3.5632	¢					
Primary								
Summer-On Peak kWh		9.1899	¢					
Summer-Off Peak kWh		4.8812	¢					
Winter-On Peak kWh		3.8791	¢					
Winter-Off Peak kWh		3.1789	¢					
Transmission								
Summer-On Peak kWh		8.9899	¢					
Summer-Off Peak kWh		4.6811	¢					
Winter-On Peak kWh		3.6791	¢					
Winter-Off Peak kWh		2.9788	¢					
Total				$0		$0		$0
Schedule No. 23 - Composite								
Customer Charge	1,134,470	$10.00		$11,344,703				
Seasonal Service	0	$117.00		$0				
Minimum Charge	102	$10.00		$1,020				
kW over 15 (Jun - Sept)	303,570	$8.89		$2,698,737	1.83%	$49,387	3.77%	$101,674
kW over 15 (Oct - May)	353,344	$7.87		$2,780,817	1.83%	$50,889	3.77%	$104,766
First 1,500 kWh (Jun - Sept)	245,732,054	11.7120	¢	$28,780,138	1.83%	$526,677	3.77%	$1,084,282
All Add'l kWh (Jun - Sept)	255,089,575	6.5567	¢	$16,725,458	1.83%	$306,076	3.77%	$630,126
First 1,500 kWh (Oct - May)	491,138,812	10.3646	¢	$50,904,573	1.83%	$931,554	3.77%	$1,917,813
All Add'l kWh (Oct - May)	394,638,630	5.8024	¢	$22,898,512	1.83%	$419,043	3.77%	$862,694
Voltage Discount	11,994	($0.48)		($5,757)				
Subscriber Solar kWh	2,069,676	10.3811	¢	$214,855				
Subscriber Solar kWh Adj	(150,134)							
Total	1,388,518,613			$136,343,056		$2,283,625		$4,701,356

Schedule No. 23-135 - Composite								
Customer Charge	18,738	$10.00		$187,380				
Seasonal Service	0	$117.00		$0				
Minimum Charge	10	$10.00		$100				
kW over 15 (Jun - Sept)	6,794	$8.89		$60,399	1.83%	$1,105	3.77%	$2,276
kW over 15 (Oct - May)	9,813	$7.87		$77,228	1.83%	$1,413	3.77%	$2,910
First 1,500 kWh (Jun - Sept)	2,193,840	11.7120	¢	$256,943	1.83%	$4,702	3.77%	$9,680
All Add'l kWh (Jun - Sept)	2,240,351	6.5567	¢	$146,893	1.83%	$2,688	3.77%	$5,534
First 1,500 kWh (Oct - May)	5,247,056	10.3646	¢	$543,836	1.83%	$9,952	3.77%	$20,489
All Add'l kWh (Oct - May)	4,722,287	5.8024	¢	$274,006	1.83%	$5,014	3.77%	$10,323
Voltage Discount	0	($0.48)		$0				
Total	14,403,534			$1,546,785		$24,875		$51,211
Schedule No. 23-136 - Composite								
Customer Charge	1,546	$10.00		$15,460				
Seasonal Service	0	$117.00		$0				
Aggregate Charge	393	$2.00		$786				
Minimum Charge	0	$10.00		$0				
kW over 15 (Jun - Sept)	552	$8.89		$4,907	1.83%	$90	3.77%	$185
kW over 15 (Oct - May)	982	7.8700		$7,728	1.83%	$141	3.77%	$291
First 1,500 kWh (Jun - Sept)	228,752	11.7120	¢	$26,791	1.83%	$490	3.77%	$1,009
All Add'l kWh (Jun - Sept)	234,472	6.5567	¢	$15,374	1.83%	$281	3.77%	$579
First 1,500 kWh (Oct - May)	417,772	10.3646	¢	$43,300	1.83%	$792	3.77%	$1,631
All Add'l kWh (Oct - May)	648,715	5.8024	¢	$37,641	1.83%	$689	3.77%	$1,418
Voltage Discount	0	($0.48)		$0				
Total	1,529,711			$151,987		$2,484		$5,114

Schedule No.31 - Composite

Secondary Voltage			
Customer Charge per month	0	$137.00	$0
Facilities Charge, per kW month	0	$5.75	$0
Back-up Power Charge			
Regular, per On-Peak kW day			
Jun - Sept	0	$0.90	$0
Oct - May	0	$0.80	$0
Maintenance, per On-Peak kW day			
Jun - Sept	0	$0.45	$0
Oct - May	0	$0.40	$0
Excess Power, per kW month			
Jun - Sept	0	$41.89	$0
Oct - May	0	$37.07	$0
Primary Voltage			
Customer Charge per month	25	$621.00	$15,525
Facilities Charge, per kW month	34,929	$4.58	$159,975
Back-up Power Charge			
Regular, per On-Peak kW day			
Jun - Sept	67,470	$0.88	$59,374
Oct - May	47,316	$0.78	$36,906
Maintenance, per On-Peak kW day			
Jun - Sept	1,510	$0.44	$664
Oct - May	0	$0.39	$0
Excess Power, per kW month			
Jun - Sept	142	$39.56	$5,618
Oct - May	655	$35.01	$22,932
Transmission Voltage			
Customer Charge per month	59	$696.00	$41,064
Facilities Charge, per kW month	291,905	$2.70	$788,144
Back-up Power Charge			
Regular, per On-Peak kW day			
Jun - Sept	657,860	$0.78	$513,131
Oct - May	307,104	$0.69	$211,902
Maintenance, per On-Peak kW day			
Jun - Sept	0	$0.39	$0
Oct - May	150,561	$0.35	$51,944
Excess Power, per kW month			
Jun - Sept	6,767	$33.21	$224,732
Oct - May	1,067	$29.39	$31,359
Subtotal			$2,163,270

Supplemental billed at Schedule 8/9 rate								
Schedule 8								
Facilities kW	27,799	$4.81		$133,713				
On-Peak kW (Jun - Sept)	2,699	$15.73		$42,455	2.45%	$1,040	5.27%	$2,238
On-Peak kW (Oct - May)	26,884	$13.92		$374,225	2.45%	$9,169	5.27%	$19,726
On-Peak kWh (Jun - Sept)	905,085	5.8282	¢	$52,750	2.45%	$1,292	5.27%	$2,781
On-Peak kWh (Oct - May)	2,558,532	5.1577	¢	$131,961	2.45%	$3,233	5.27%	$6,956
Off-Peak kWh (Jun - Sept)	4,024,260	2.9624	¢	$119,215	2.45%	$2,921	5.27%	$6,284
Off-Peak kWh (Oct - May)	7,522,766	2.6216	¢	$197,217	2.45%	$4,832	5.27%	$10,396
Voltage Discount	27,713	($1.13)		($31,316)				
Schedule 9						$22,487		$48,380
Facilities kW	283,278	$2.28		$645,874				
On-Peak kW (Jun - Sept)	96,907	$14.33		$1,388,677	2.95%	$40,966	6.59%	$91,488
On-Peak kW (Oct - May)	180,946	$12.68		$2,294,395	2.95%	$67,685	6.59%	$151,159
On-Peak kWh (Jun - Sept)	14,609,917	5.1477	¢	$752,075	2.95%	$22,186	6.59%	$49,548
On-Peak kWh (Oct - May)	21,736,230	4.5555	¢	$990,194	2.95%	$29,211	6.59%	$65,236
Off-Peak kWh (Jun - Sept)	47,389,695	2.6165	¢	$1,239,951	2.95%	$36,579	6.59%	$81,690
Off-Peak kWh (Oct - May)	90,512,658	2.3155	¢	$2,095,821	2.95%	$61,827	6.59%	$138,076
						$258,453		$577,197
Total (Aggregated)	189,259,143			$12,590,477		$280,939		$625,577

Schedule 32 - Service From Renewable Energy Facilities - Commercial

Customer Charges:				
Distribution Voltage < 1 MW		$55.00		$0
Distribution Voltage > 1 MW		$72.00		$0
Transmission Voltage	36	$266.00		$9,576
Administrative Fee:				
All Voltages / per Generator	13	$113.00		$1,451
All Voltages / per Delivery Point	39	$154.00		$5,932
Delivery Facilities Charges:				
Secondary Voltage < 1 MW		$7.52		$0
Primary Voltage < 1 MW		$6.56		$0
Secondary Voltage > 1 MW		$8.37		$0
Primary Voltage > 1 MW		$7.24		$0
Transmission Voltage	245,396	$4.35		$1,067,470
Daily Power Charges:				
On-Peak Secondary Voltage < 1 MW				
June - September:		$0.57		$0
October - May:		$0.48		$0
On-Peak Primary Voltage < 1 MW				
June - September:		$0.57		$0
October - May:		$0.47		$0
On-Peak Secondary Voltage > 1 MW				
June - September:		$0.72		$0
October - May:		$0.61		$0
On-Peak Primary Voltage > 1 MW				
June - September:		$0.71		$0
October - May:		$0.59		$0
On-Peak Transmission Voltage				
June - September:	526,626	$0.71		$373,905
October - May:	913,271	$0.61		$557,095
Renewable Energy PPA	172,556,857	5.7290	¢	$9,885,782
Subtotal	172,556,857			$11,901,211

Supplemental billed at Schedule 8/9 rate								
Schedule 9								
Facilities kW	41,883	$2.28		$95,492				
On-Peak kW (Jun - Sept)	15,180	$14.33		$217,530	2.95%	$6,417	6.59%	$14,331
On-Peak kW (Oct - May)	26,325	$12.68		$333,802	2.95%	$9,847	6.59%	$21,991
On-Peak kWh (Jun - Sept)	4,703,542	5.1477	¢	$242,124	2.95%	$7,143	6.59%	$15,952
On-Peak kWh (Oct - May)	4,209,024	4.5555	¢	$191,742	2.95%	$5,656	6.59%	$12,632
Off-Peak kWh (Jun - Sept)	6,552,517	2.6165	¢	$171,447	2.95%	$5,058	6.59%	$11,295
Off-Peak kWh (Oct - May)	8,628,050	2.3155	¢	$199,782	2.95%	$5,894	6.59%	$13,162
Total (Aggregated)	196,649,990			$13,353,130		$40,015		$89,364
Schedule 34 - Renewable Energy Purchases for Qualified Customers – 5,000 kW and Over - Commercial								
Customer Charge	12							
Total	242,230,000	5.3783	¢	$13,027,758		$0		$0
Contract 1								
Monthly Fixed Charge	12	$232.00		$2,784				
Customer Charge per HLH kW	1,004,562	$1.92		$1,928,759				
Demand Charge per HLH kW (May - Se	381,956	$12.93		$4,938,691	2.03%	$100,255	4.07%	$200,844
Demand Charge per HLH kW (Oct - Ap	622,606	$8.67		$5,397,994	2.03%	$109,579	4.07%	$219,523
kWh HLH (May - Sept)	101,240,704	4.3940	¢	$4,448,517	2.03%	$90,305	4.07%	$180,910
kWh LLH (May - Sept)	142,951,672	2.7600	¢	$3,945,466	2.03%	$80,093	4.07%	$160,452
kWh HLH (Oct - Apr)	168,476,287	3.3060	¢	$5,569,826	2.03%	$113,067	4.07%	$226,511
kWh LLH (Oct - Apr)	204,431,337	2.7600	¢	$5,642,305	2.03%	$114,539	4.07%	$229,458
Total	617,100,000			$31,874,342		$607,839		$1,217,698
Contract 2								
Customer Charge	12							
On-Peak kWh (May-Sept)	57,264,151	6.5680	¢	$3,761,109	3.11%	$116,970	7.19%	$270,560
On-Peak kWh (Oct-Apr)	179,663,027	4.9410	¢	$8,877,150	3.11%	$276,079	7.19%	$638,588
Off-Peak kWh (May - Sept)	239,492,626	4.1280	¢	$9,886,256	3.11%	$307,463	7.19%	$711,179
Off-Peak kWh (Oct-Apr)	229,035,745	4.1280	¢	$9,454,596	3.11%	$294,038	7.19%	$680,127
Total	705,455,549			$31,979,111		$994,550		$2,300,453
Contract 3								
Customer Charge	12							
Block 1	376,680,000	5.8419	¢	$22,005,408				
Block 2 - Market								
Block 2 - Index	911,946,197	4.4906	¢	$40,952,185				
Total	1,288,626,197			$62,957,593		$0		$0
Lighting Contract - Post Top Lighting - Composite								
Customers	4							
Energy Only Res	48	$2.1800		$105				
Energy Only Non-Res	207	$2.1858		$452				
Subtotal	255			$557				
Total	7,387			$557		$0		$0
Annual Guarantee Adjustment								
Residential				$6,795				
Commercial				$3,742,344				
Industrial				$823,370				
Irrigation				$231,623				
Public Street & Highway Lighting				$4,655				
Total AGA				$4,808,787		$0		$0
TOTAL - ALL CLASSES	24,837,388,161			$2,033,141,225		$37,509,263		$77,672,285

Rocky Mountain Power
Exhibit RMP___(RMM-3)
Docket No. 22-035-01
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Schedule 94

March 2022

Second~~First~~ Revision of Sheet No. 94.11
P.S.C.U. No. 51 **Canceling First Revision~~Original~~ 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	3.53~~1.70~~%
Schedule 2	3.53~~1.70~~%
Schedule 2E	3.53~~1.70~~%
Schedule 3	3.53~~1.70~~%
Schedule 6	4.68~~2.25~~%
Schedule 6A	4.35~~3.42~~%
Schedule 7*	2.61~~1.06~~%
Schedule 8	5.27~~2.45~~%
Schedule 9	6.59~~2.95~~%
Schedule 9A	7.21~~3.27~~%
Schedule 10	4.43~~2.18~~%
Schedule 11*	2.61~~1.06~~%
Schedule 12*	2.61~~1.06~~%
Schedule 15 (Traffic and Other Signal Systems)	4.21~~1.92~~%
Schedule 15 (Metered Outdoor Nighttime Lighting)	9.38~~2.84~~%
Schedule 22	6.59~~2.95~~%
Schedule 23	3.77~~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

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	3.53%
Schedule 2	3.53%
Schedule 2E	3.53%
Schedule 3	3.53%
Schedule 6	4.68%
Schedule 6A	4.35%
Schedule 7*	2.61%
Schedule 8	5.27%
Schedule 9	6.59%
Schedule 9A	7.21%
Schedule 10	4.43%
Schedule 11*	2.61%
Schedule 12*	2.61%
Schedule 15 (Traffic and Other Signal Systems)	4.21%
Schedule 15 (Metered Outdoor Nighttime Lighting)	9.38%
Schedule 22	6.59%
Schedule 23	3.77%
Schedule 31	**
Schedule 32	**

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