ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

April 4, 2019

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 Secretary

RE: Docket No. 19-035-T06
In the Matter of the Application of Rocky Mountain Power for Approval of an Indoor Agricultural Lighting Tariff, Electric Service Schedule 22

Enclosed for filing are proposed tariff sheets associated with Tariff P.S.C.U No. 50 of PacifiCorp, d.b.a. Rocky Mountain Power, applicable to electric service in the State of Utah. Pursuant to the requirement of Rule R746-405D, Rocky Mountain Power (the "Company") states that the proposed tariff sheets do not constitute a violation of state law or Commission rule. The Company respectfully requests an effective date of August 1, 2019, for the new tariff.

Eighth Revision of Sheet No. B		Electric Service Schedules Index
Original Sheet No. 22.1	Schedule 22	Indoor Agricultural Lighting Service – 1,000 kW and Over
Original Sheet No. 22.2	Schedule 22	Indoor Agricultural Lighting Service – 1,000 kW and Over
Original Sheet No. 22.3	Schedule 22	Indoor Agricultural Lighting Service – 1,000 kW and Over

In this filing, the Company proposes to implement a new tariff option, Schedule 22, Indoor Agricultural Lighting Service – 1,000 kW and Over, to offer cost-based rates that reflect the unique load profile of qualifying indoor agricultural lighting customers with loads greater than one megawatt ("MW"). In support of this filing, attached is the direct testimony of Robert M. Meredith. Mr. Meredith's testimony explains how Schedule 22 is reasonable and in the public interest, and provides an overview of the specific features in the proposed tariff.

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
Jana.saba@pacificorp.com

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

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

Sincerely,

Joelle Steward
Vice President, Regulation

Enclosures

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Yvonne R. Hogle (7550)
Rocky Mountain Power
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Attorneys for Rocky Mountain Power

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of an Indoor Agricultural Lighting Tariff, Electric Service Schedule 22	Docket No. 19-035-T06

APPLICATION

Rocky Mountain Power, a division of PacifiCorp, (Rocky Mountain Power or the Company), respectfully submits an application ("Application") to the Public Service Commission of Utah ("Commission") requesting approval of its proposed Indoor Agricultural Lighting Tariff, Electric Service Schedule 22 ("proposed Schedule 22"). In support of the Application, the Company states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon corporation that 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. The Company serves approximately 910,000 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. Rocky Mountain Power files this Application pursuant to UTAH ADMIN. R. 746-405-2(E)(1).

4. Communications regarding this Application should be addressed to:

Jana Saba
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Rocky Mountain Power
1407 West North Temple, Suite 330
Salt Lake City, UT 84116
Telephone: 801.220.2823
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Rocky Mountain Power
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In addition, Rocky Mountain Power respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@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.

BACKGROUND

5. The Company was approached by a customer with a tomato production business in Utah about its plans to expand its operations either at its existing site in Utah or outside of the Company's service territory.

6. The Customer inquired about alternative rate schedule options that include more competitive electricity prices than those it pays under Schedule 9 – General Service High Voltage ("Schedule 9").

7. The Company evaluated the Customer's request and studied its energy consumption history over the course of calendar year 2018 to understand the unique characteristics of the Customer's electric service. The Company compared the Customer's usage patterns with typical Schedule 9 customers which tend to have high load factors relative to customers on other schedules.

8. Based on this evaluation, it became evident that the Customer's energy usage patterns are different from the patterns that typical Schedule 9 customers exhibit. The Customer primarily uses energy outside of the summer months, when the Company's system typically peaks, and during nighttime and morning hours.

9. There are no effective rate schedules that account for the Customer's unique load profile and energy consumption patterns. The Company considered offering a special contract to the Customer but determined there may be other potential customers with energy usage patterns, load profiles, and load sizes similar to those exhibited by the Customer that would justify creating a different class of customers.

10. This prompted the Company to develop proposed Schedule 22 which accurately reflects the cost to serve the Customer's unique load profile and would not harm other customers, assuming the larger load from the Customer's tomato production business expansion remains in Utah.

11. Proposed Schedule 22 is appropriate for the Customer and others with similarly unique load profiles, characteristics and size, without increasing costs to other customers.

12. Further justification for proposed Schedule 22 is set forth below. In addition, the Application is supported by the direct testimony and attached exhibits of Mr. Robert M. Meredith which includes additional detail and support for proposed Schedule 22.

Separate Class Treatment

13. The energy usage patterns of the Customer and other potential customers with similar unique characteristics that use energy primarily for indoor agricultural lighting and exhibit cost causative characteristics are different from Schedule 9 customers.

14. The Customer exhibits a distinct seasonal pattern of energy consumption because it uses its lighting almost exclusively during the months of November through March. The Customer's usage profile is driven by the fact that it must supplement light to its tomato crop when the sun is not shining. A detailed analysis of the Customer's usage patterns for calendar year 2018 is included in the direct testimony of Mr. Meredith.

15. In addition, the Customer's hourly profile and seasonal pattern complement the Company's other Utah customers. The Customer adds load to the Company's system during the night and the morning which has negligible impact on the Company's peaks.

Overview of Schedule 22

16. Proposed Schedule 22 includes the conditions that must be met to be eligible for service, and provides the prices for the types of services provided.

17. Proposed Schedule 22 is available for any customer with loads over one MW that uses at least 75 percent of its energy for indoor agricultural lighting.

18. It includes Customer Service Charges, a Facilities Charge, Power Charges, and Energy Charges (as defined in the direct testimony of Mr. Meredith), for service at secondary, primary and transmission voltage.

19. The summer and winter seasons are similar to those for Schedule 9 but include May in the lower cost winter period. The on- and off-peak periods are also modified to reflect when the Company's peaks primarily occur.

20. The specific components and basis for the proposed rates in proposed Schedule 22 are described in detail in the direct testimony of Mr. Meredith.

Cost of Service/Rate Design

21. The Company would typically include a cost of service analysis for a new proposed service either in, or contemporaneously with, a general rate case filing. In light of the time-sensitive opportunity related to the Customer's expansion, as more fully explained in the direct testimony of Mr. Meredith, the Company performed a cost of service analysis in this docket.

22. The analysis evaluates the Customer's cost of service and demonstrates that the Customer is paying prices that are 17 percent higher than its cost of service, as explained in more detail in the direct testimony of Mr. Meredith.

23. Mr. Meredith's analysis also shows the impacts that a simultaneous expansion of the Customer's load with a reduction in prices for the Customer, would have on other customers.

24. Mr. Meredith explains in detail the prices for service under proposed Schedule 22.

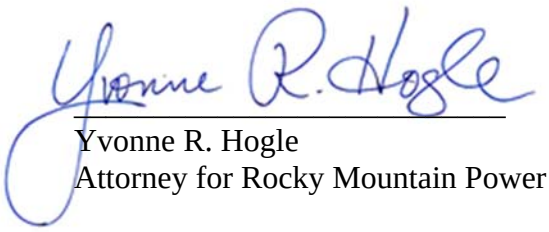
25. In his testimony, Mr. Meredith also explains the reasons behind the calculation of the prices for the different components and services and explains how the on- and off-peak period were calculated and how they account for seasons and time-of-use.

CONCLUSION

26. Indoor agricultural lighting loads are becoming more common across the West. Proposed Schedule 22 not only supports the Customer's expansion in Utah by providing more competitive pricing, while keeping other customers harmless, but also allows the Company to provide service options for other customers with similarly unique characteristics, load profiles and load sizes. Based on the foregoing, the Company respectfully requests that the Commission approve proposed Schedule 22 to be effective August 1, 2019, at the conclusion of this proceeding, in light of the time-sensitive opportunity related to the Customer's expansion.

DATED: April 4, 2019.

Respectfully submitted,



Yvonne R. Hogle
Attorney for Rocky Mountain Power

Rocky Mountain Power
Docket No. 19-035-T06
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Robert M. Meredith

April 2019

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

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

Qualifications

Q. Please describe your education and professional background.

A. I graduated from Oregon State University with a Bachelor of Science degree in Business Administration and a minor in Economics. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 14 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over eight years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. I assumed my present position in March 2016.

Q. Have you testified in previous regulatory proceedings?

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

Purpose and Summary

Q. What is the purpose of your testimony?

A. My testimony presents and supports the Company's proposed Indoor Agricultural Lighting Tariff, Schedule 22 ("proposed Schedule 22").

Q. Please summarize the purpose of proposed Schedule 22.

A. Proposed Schedule 22 would provide service to indoor agricultural lighting customers

with loads greater than one megawatt ("MW"). The cost-based rates provided under service from this schedule reflect a unique and beneficial load profile.

Q. Why is the Company proposing Schedule 22?

A. An economic opportunity to provide cost-based rates to an existing customer to expand its facilities with predominantly off-peak, non-summer load arose. Offering a lower rate that is available to any other similarly situated customer in conjunction with the customer's expansion will provide net benefits for all customers while minimally impacting the Company's system. If the Company does not offer this rate, the customer may locate its expansion outside of the Company's service area.

Background

Q. Please elaborate on the economic opportunity that is driving the filing for approval of proposed Schedule 22 now.

A. A large greenhouse tomato grower located in Utah ("Customer A") approached the Company about its plans to expand its operations and energy usage to a footprint roughly 2.6 times its current size, either at its existing site in Utah, or outside of the Company's service territory. Electricity to light its crop is a major input into Customer A's tomato production, which prompted the Customer to inquire about other rate schedule options that reflect its unique and beneficial load profile in Utah. Customer A is currently served at transmission voltage on Schedule 9 – General Service High Voltage ("Schedule 9"), and is therefore already receiving service at one of the lowest average prices the Company offers. In evaluating Customer A's energy usage patterns, it became clear that Customer A uses electricity differently from other Schedule 9 customers. Schedule 9 customers tend to have high load factors relative to customers

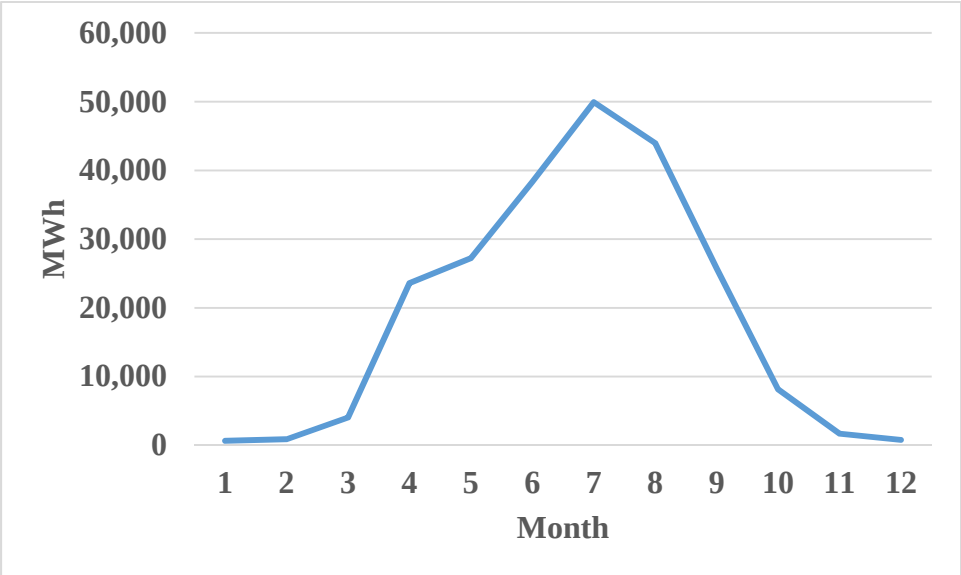
on other Schedules, and use power steadily throughout the year. In contrast, Customer A primarily uses energy outside of the summer months, when the Company's system typically peaks, and during nighttime and morning hours. A cost of service analysis performed by the Company indicated that Customer A pays more than its cost of service, and that the Company could offer the customer a lower set of prices in conjunction with Customer A's expansion without increasing costs to other customers.

Separate Class Treatment

Q. Please describe existing classes and some of the characteristics that distinguish them from other classes.

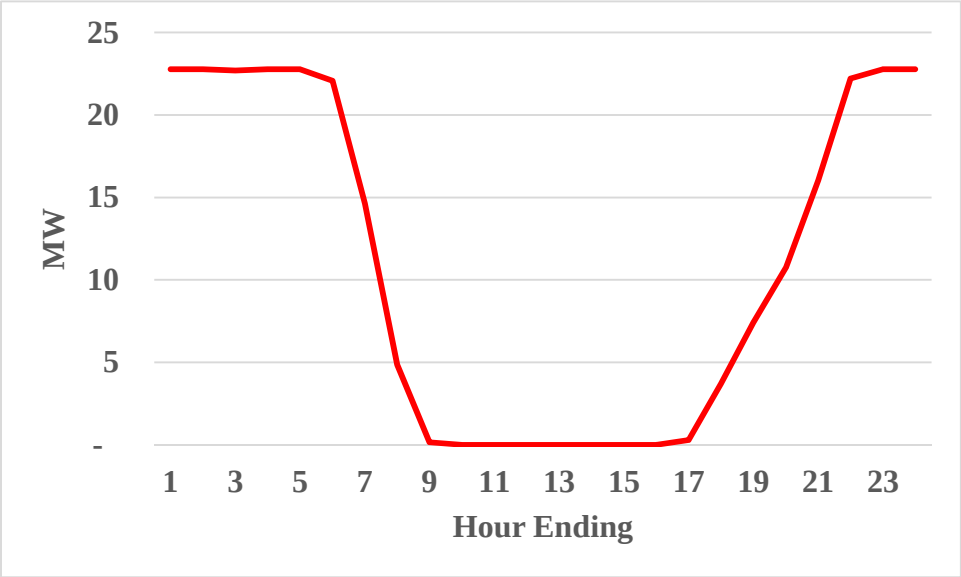
A. Schedule 10 – Irrigation and Soil Drainage Pumping Power Service ("Schedule 10") is offered to customers who use energy to pump water, typically for watering crops. Primarily using energy during the summer growing season distinguishes these customers from those in other classes. Figure 1 below shows monthly usage for the Schedule 10 Irrigation class during 2017.

Figure 1. Schedule 10 Monthly Energy Usage in 2017.



Customers on the street and area lighting classes, that take service from Schedules 7, 11, 12, and 15-metered outdoor nighttime lighting, are unique from other classes because they are controlled by photocells which cause them to only use energy when it is dark outside. Figure 2 below shows the average hourly profile for the street and area lighting class in 2017.

Figure 2. Street and Area Lighting Average Hourly Profile in 2017



Finally, the largest customer class, Residential, is on a different class from general service customers because those customers are smaller than commercial and industrial customers that are on general service rate schedules and have a different average profile. Table 1 below shows the differences in size expressed in average monthly kWh usage for residential customers as compared to customers on general service rate schedules:

Table 1. Comparison of Average Size between Residential Customers and Customers on General Service Rate Schedules

Class	Average Monthly Energy Usage (kWh)
Residential	688
Sch 23	1,276
Sch 6	32,705
Sch 8	674,662

Figure 3 compares the average hourly energy usage profile of residential customers with other general service classes:

Figure 3. Comparison of Residential and General Service Load Profiles in 2017

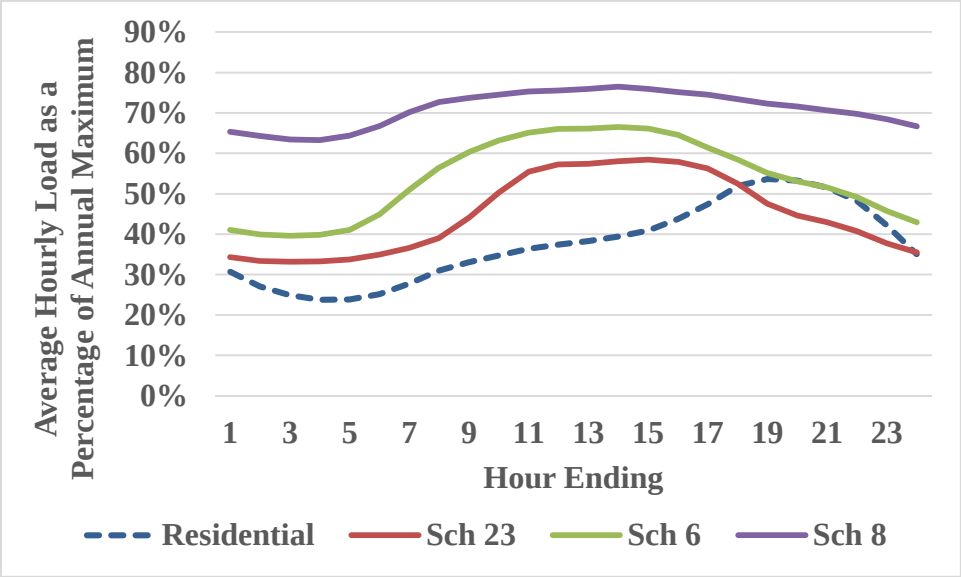


Figure 3 shows that the load factor for the residential class is less than for the general service rate schedules. Figure 3 also shows that the residential class peaks in the late afternoon/early evening and the general service classes peak more towards the middle of the day.

A comparison of these different classes shows their distinct characteristics that warrant separate class treatment with different rates under different schedules.

Q. What characteristics does Customer A (and other potential indoor agricultural lighting customers) have that justify separate class treatment?

A. Customer A uses energy primarily for indoor agricultural lighting and exhibits cost causative characteristics that are different from Schedule 9 customers. First, Customer A exhibits a distinct seasonal pattern of energy consumption. Customer A uses its lighting almost exclusively during the months of November through March. In contrast, Schedule 9 customers have far less of a seasonal pattern of energy consumption. In my testimony as well as in the analysis prepared for this filing, data for Customer A reflects the most recent calendar year, 2018. For other customers, I used data from 2017 to stay consistent with the Company's most recently filed class cost of service study. Table 2 below compares the monthly usage for Customer A in 2018 with all Schedule 9 customers during 2017:

Table 2. Comparison of the Monthly Energy Usage for Customer A in 2018 and all Schedule 9 customers in 2017

MWh	Customer A	Sch 9
January	5,138	473,555
February	5,194	279,035
March	3,080	294,156
April	2,898	414,550
May	1,498	440,519
June	476	360,229
July	378	424,186
August	364	448,337
September	378	271,904
October	364	457,734
November	1,680	494,402
December	3,752	430,476

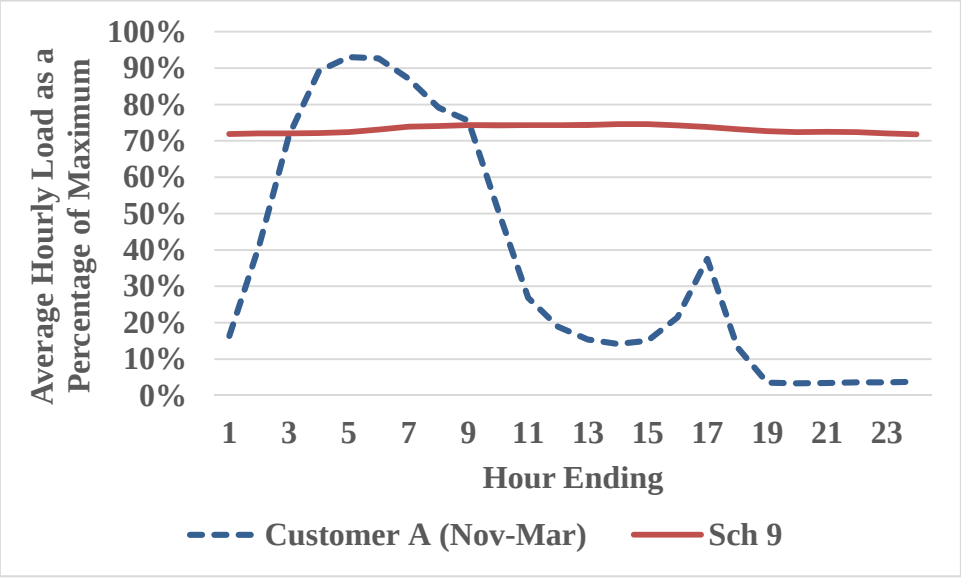
Ratio of Highest to Lowest Month's Usage	**14.3**	**1.8**

Customer A's January usage is about 14 times greater than its usage in the month of July. In contrast, Schedule 9's highest usage month of November has energy consumption that is only 1.8 times greater than its consumption in its lowest usage month of September.

Second, Customer A's unique hourly profile is due to its operations, largely driven by supplementing light to its tomato crop when the sun is not shining. Also to avoid higher cost on-peak periods and give the plants an opportunity to rest, lighting is typically delayed in the evening until around midnight. Customer A therefore primarily uses power in the nighttime and morning. In contrast, Schedule 9 customers use power more steadily throughout each 24-hour day. Figure 4 below compares the average

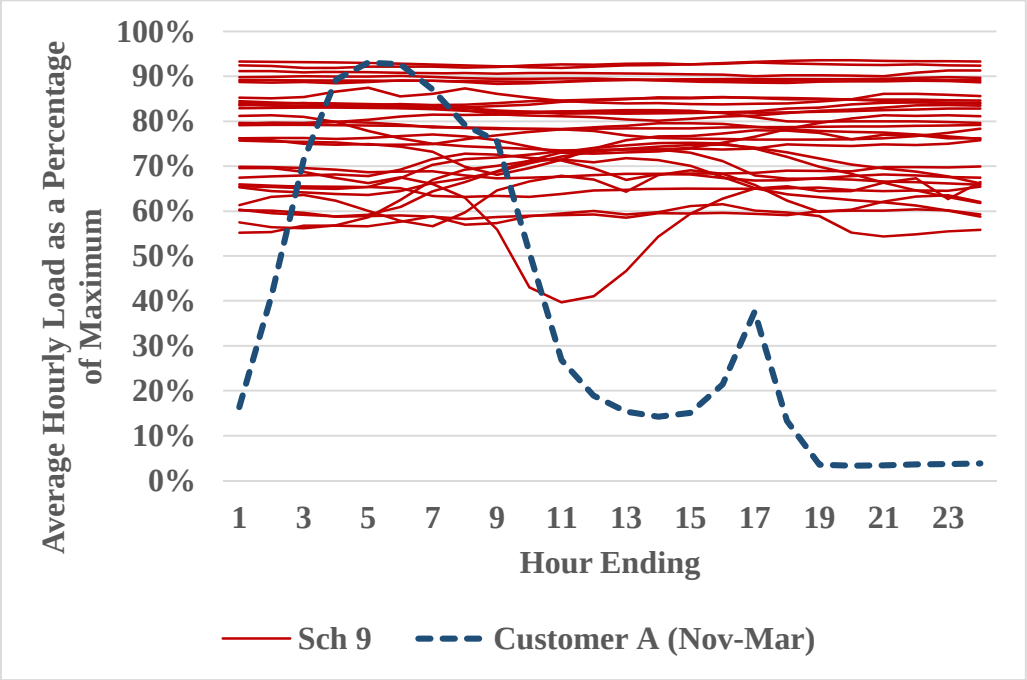
hourly profile for Customer A for the months of November through March and the average hourly profile for Schedule 9:

Figure 4. Comparison of Customer A in 2018 and Schedule 9 Profiles in 2017



The graph of the average hourly profiles of individual Schedule 9 customers consistently shows very steady levels of consumption across each hour. Figure 5 shows a comparison of the average hourly profile for Customer A to the 30 largest Schedule 9 customers, who comprise over 75 percent of the class' load:

Figure 5. Comparison of Customer A in 2018 and Top 30 Schedule 9 Profiles in 2017



Finally, Customer A's unique profile leads to a contribution of more than one MW in only two of the Company's 12 monthly system coincident peaks. Since 75 percent of fixed generation and transmission costs are allocated to the states the Company serves based upon each state's contribution to the 12 monthly system coincident peaks, it is a significant factor in determining cost responsibility at the customer class level. In contrast to Customer A, Schedule 9 customers contribute significantly to each of the monthly system peaks, with far less monthly variation. Table 3 below shows the loads of both Customer A and Schedule 9 customers during the times of the Company's 12 system coincident peaks in 2017:

Table 3. Customer A and Schedule 9 Loads at the Time of the Company's 12 System Coincident Peaks in 2017

Month	Peak Day	Hour Ending (MST)	Customer A (kW)*	Schedule 9 (kW)
Jan-17	6	9	***14,732***	638,706
Feb-17	1	20	367	414,948
Mar-17	6	9	***5,117***	408,305
Apr-17	3	9	515	603,027
May-17	30	18	574	637,734
Jun-17	26	18	614	533,237
Jul-17	6	18	591	593,339
Aug-17	1	18	628	637,986
Sep-17	5	18	534	395,085
Oct-17	31	9	***5,405***	630,430
Nov-17	7	19	603	702,782
Dec-17	12	19	557	594,214

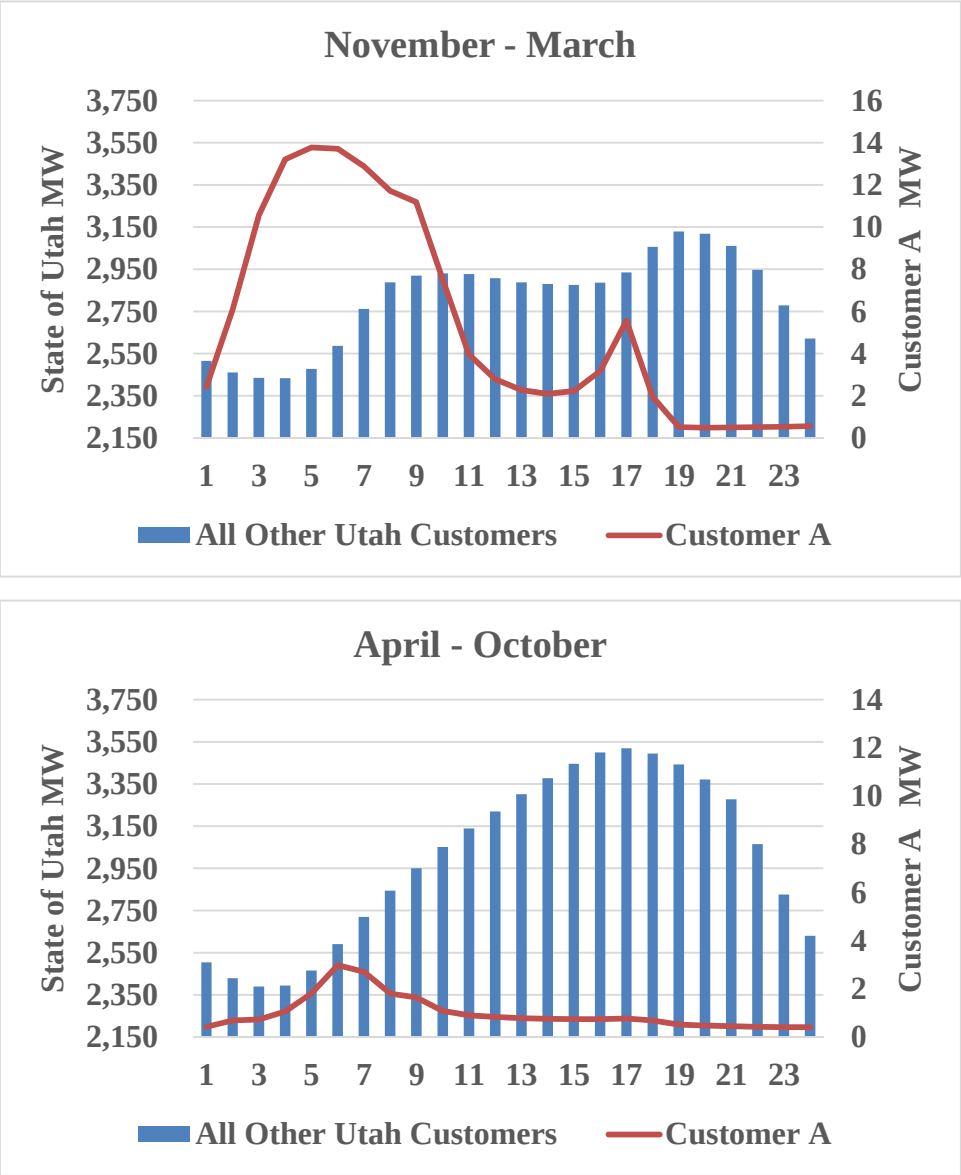
* - Customer A's loads are from 2018.

These differences in characteristics suggest that Customer A and other potential indoor agricultural lighting customers are a prime candidate for separate class treatment in the Company's class cost of service study.

Q. Why are the characteristics of Customer A particularly beneficial to the Company's system?

A. Both the hourly profile and the seasonal pattern of Customer A's usage complement the usage of the Company's other customers in Utah. Since the bulk of Customer A's usage occurs during the night and morning, additional load can be added at these times with minimal impact to the Company's peaks. Having more load with this same hourly pattern can also increase the use of the Company's system. Figure 6 below illustrates the timing of Customer A's loads relative to the rest of the Company's customers in Utah for both the November through March period, when Customer A lights more extensively, as well as April through October, when it uses less lighting.

Figure 6. Comparison of Profiles for Customer A in 2018 and All Other Utah Customers in 2017



As compared to the profiles of the general service classes or transmission voltage (Schedule 9) customers, which are more steady throughout each 24-hour day, Customer A's loads occur during some of the Company's lowest usage times, which helps the Company's system operate more efficiently. Along with its unique profile, Customer A uses less energy during summer months, when the loads for all other customers are at their highest and wholesale power prices are similarly elevated. Table 4 below

compares the monthly usage for Customer A in 2018 and All Other Utah customers during 2017:

Table 4. Comparison of the Monthly Energy Usage for Customer A in 2018 and All Other Utah Customers in 2017

MWh	Customer A	All Other Utah Customers
January	5,138	2,091,836
February	5,194	1,610,279
March	3,080	1,772,878
April	2,898	1,877,415
May	1,498	1,864,533
June	476	1,918,405
July	**378**	**2,423,994**
August	**364**	**2,359,742**
September	378	1,744,926
October	364	1,978,293
November	1,680	1,993,299
December	3,752	2,068,255

Q. Why is it appropriate to establish a cost of service class outside of a general rate case?

A. The Company recognizes that generally the most logical time to establish a new customer class for a cost of service study is during a general rate case when rates are set for all customers and any potential impacts to other customers can be addressed. In this instance, developing a separate class and tariff for indoor agricultural lighting is time-sensitive because Customer A is looking to expand its facilities in the near-term. If the Company were to wait to make a filing until the next general rate case, the opportunity to serve this incremental load could be missed and Customer A may elect to expand its facilities in another location.

Perhaps more important than the timing, the Company's analysis indicates that

its proposed rates could be offered to Customer A in conjunction with its expansion while still providing net benefits to all other customers. The proposed tariff would only become effective once Customer A's expansion materializes. It is therefore appropriate for rates and separate class treatment for indoor agricultural lighting to be established outside of a general rate case, since there would be no adverse bill impacts to other customers.

Q. Why isn't a special contract for this customer more appropriate?

A. Developing a new tariff that is open to any other similarly situated customer, indoor agricultural lighting customer with a load greater than one MW, is more transparent than executing a special contract with this particular customer. Presently, only Customer A would qualify for this proposed new tariff. The Company has identified that the characteristics of Customer A's energy consumption as an indoor agricultural lighting customer are beneficial to its system and ultimately to other customers. Further, if the proposed tariff were to induce other similar customers to locate within the Company's service territory, it could provide additional benefits.

Cost of Service Analysis

Q. Please describe the cost of service analysis the Company prepared to evaluate Customer A.

A. To understand how Customer A's revenue compares to its costs, the Company modified the 2017 annual cost of service study filed on June 15, 2018 to have Customer A separately identified as a separate class in the study with its loads removed from the Schedule 9 class. All of the pertinent factors related to energy, demand, and customer

were input for this separate class. As mentioned earlier, the Company used data for Customer A from the most recent calendar year, 2018.

Q. What were the results of this analysis?

A. The cost of service study demonstrated that Customer A's revenue was 17 percent higher than its cost of service, indicating that a 17 percent reduction in its prices could be justified, as shown in the cost of service summary in attached Exhibit RMP___(RMM-1).

Q. What additional analysis was prepared to understand the impacts to other customers?

A. The cost of service study is a helpful regulatory tool to understand how costs can be allocated given a static revenue requirement. However, any customer within a given class could be separated and shown to have present revenue levels either more or less than its cost of service. This can be problematic because separating a customer who pays more than cost of service and resetting its rates potentially puts upward pressure on the rates of other customers. With its very unique characteristics and a possible considerable expansion, it was important to understand the marginal impact to all other Utah customers from a simultaneous expansion of its facility and a lowering of its average price.

Q. Please describe how you determined the marginal impact of a simultaneous expansion of Customer A's facility and a lowering of its average price.

A. Attached Exhibit RMP___(RMM-2) shows the marginal impact of an expansion and lower average price for Customer A, determined by calculating the incremental difference in revenue and expense. To determine incremental annual revenue, the

difference was taken between Customer A's revenue at its current size and at current rates, and Customer A's revenue at an average energy price that is 17 percent lower but for 2.6 times greater energy sales. Current revenue for Customer A is $1.697 million for 25,200 megawatt hours ("MWh") or $67.36 per MWh. At 2.6 times present energy sales, Customer A's loads would be 65,520 MWh. Given an average cost of energy set to equal a cost of service that is about 17 percent lower ($55.90 per MWh), annual revenue for the expanded facility would be $3.663 million.

To determine the incremental expense associated with Customer A's additional load from its expansion, the incremental power cost and increase in wheeling expense were determined for the additional 40,320 MWh of energy sales. To determine the incremental power cost, two Generation and Regulation Initiative Decision Tool ("GRID") energy studies were conducted with and without Customer A's expansion for calendar year 2020. This analysis is very similar to the Partial Displacement Differential Revenue Requirement that the Company uses to evaluate qualifying facilities contracts in Utah and yielded an average incremental power cost of $17.37 per MWh. To account for losses, the $17.37 per MWh value was expanded by the average transmission voltage losses of 4.527 percent to $18.16 per MWh. To determine the incremental allocation of wheeling expense from Customer A's increased load, the allocation to PacifiCorp's network load in its 2017 Open Access Transmission Tariff was expanded by 2.5 MW (average of 12 coincident peaks) to account for Customer A's additional load from its expansion. Increasing the allocation to network load would effectively increase the price network customers paid for PacifiCorp's transmission system by about $9,683 or about $0.38 per MWh for Customer A.

The incremental increased revenue from Customer A's expansion offset by a lower rate of $1.965 million less the incremental expense of $0.748 million associated with the additional load produces a net benefit of $1.218 million.

Q. What are the implications of this analysis?

A. Based on this analysis, the lower set of rates that reflect Customer A's highly unique and beneficial characteristics could be offered in conjunction with the customer's expansion with no adverse impact to costs for other customers.

Proposed Schedule 22

Q. Please describe proposed Schedule 22.

A. Exhibit RMP___(RMM-3) includes proposed Schedule 22 – Indoor Agricultural Lighting Service tariff sheets that would be available for any customer with loads over one MW that uses at least 75 percent of its energy for indoor agricultural lighting. Schedule 22 lists the Customer Service Charge, the Facilities Charge, Power Charges, and Energy Charges for service at secondary, primary, and transmission voltage. The summer and winter seasons are modified slightly from Schedules 8 and 9 to include May in the lower cost winter period. The on- and off-peak periods were also modified to reflect when the Company's peaks primarily occur. The definition of Facilities kW is based upon the two highest kW readings in the preceding 12-month period for each bill instead of the highest kW reading in the given billing month on which Schedules 8 and 9 are based. The derivation of the prices and the Company's rationale for changing the seasons, time-of-use periods, and definition of the Facilities kW are discussed below.

Q. Why is this tariff limited to customers with loads greater than one MW?

A. One MW is a reasonable demarcation for what is considered a "large" load. This is recognized by Schedule 8 – Large General Service ("Schedule 8"), which is available for customers with loads that are one MW and higher. Proposed Schedule 22 is specifically intended for customers who are lighting crops on a very large scale. Making this proposed tariff available for smaller greenhouse operations would introduce administrative complexity and could open up the possibility that customers would misuse the tariff to get lower rates without detection from the Company because of their size. Further, profile metering is installed on all large customers, so limiting to only loads with one MW or greater ensures availability of comprehensive class data without incurring additional metering expense.

Q. When would Schedule 22 become available?

A. The Company proposes that Schedule 22 would become available only after the total load eligible for service under the schedule exceeds 30 MW. Ensuring that the lower level of rates and the expansion of Customer A's facilities both occur at the same time will keep other customers from being harmed. If this tariff were to be made effective without the guarantee of Customer A's expansion, the reduced revenue could ultimately result in a greater cost responsibility for other customers.

Q. If Customer A, who receives service at transmission level voltage, is the only eligible customer for Schedule 22, why is the Company also proposing rates for service at primary and secondary voltage?

A. Ultimately, the voltage of Customer A is not the unique aspect that sets it apart from other customers. The hourly profile and seasonal pattern of consumption are the

distinctive characteristics for the Company's proposed Indoor Agricultural Lighting class. The Company therefore proposes this tariff be available for indoor agricultural lighting customers over one MW at any voltage.

Proposed Rate Design

Q. What prices do you propose under Schedule 22?

A. Table 5 below lists proposed prices for Schedule 22:

Table 5. Proposed Schedule 22 Prices

Description	Unit	Secondary Price	Primary Price	Transmission Price
Customer Service Charge	customer	$70	$70	$259
Facilities Charge	kW	$1.37	$1.37	$1.37
Power Charge				
Summer - On-Peak	kW	$8.16	$8.05	$7.83
Winter - On-Peak	kW	$5.86	$5.61	$5.31
Energy Charge				
Summer - On-Peak	kWh	$0.092314	$0.088608	$0.086679
- Off-Peak	kWh	$0.050770	$0.047064	$0.045134
Winter - On-Peak	kWh	$0.041108	$0.037402	$0.035473
- Off-Peak	kWh	$0.034356	$0.030650	$0.028721

Q. How did you calculate these prices?

A. Attached Exhibit RMP___(RMM-4) demonstrates how they were calculated. The Customer Service Charges are the same prices as those for Schedules 8 and 9, depending upon voltage. Power Charges were set at a level where demand-related production cost and demand-related transmission cost would be fully recovered from both the Power Charges and the Facilities Charges. The definition of Facilities kW is based upon the two highest kW readings in the preceding 12-month period. Facilities Charges were set to a level that would use this revised definition and recover the same

level of revenue that would be recovered from Schedule 9 Facilities Charges. After determining customer service, power, and facilities charges, the remaining cost of service by voltage was recovered through energy charges. The differentials between season and time-of-use period for each energy charge were set to the same differentials as forecast 2020 Palo Verde wholesale power prices. The on-peak times for both summer and winter were revised to shorter windows and the month of May was moved to the lower cost winter season.

Q. Please explain how the Company calculated Power Charges for proposed Schedule 22?

A. Power Charges were set at a level for each of the voltage categories such that total Power Charges and Facilities Charges were equal to what the cost of service study indicated to be the demand-related production cost and the demand-related transmission cost. The relative differences in price between the summer and winter seasons for Schedule 9 and Schedule 8 were maintained.

Q. Why does the Company propose revising the definition of Facilities kW for this tariff?

A. Basing Facilities kW upon the highest two kW readings in a rolling 12-month period instead of the single highest reading on a given monthly bill is appropriate for this tariff for two reasons. First, since qualifying customers would be given shorter on-peak windows over which power charges would apply and generally more costs would be recovered over volumetric energy charges, it is important to balance these potential savings with a more stable recovery through facilities charges. Basing the Facilities kW on the top two annual readings helps to strike this balance between providing

opportunities to save commensurate with cost causality, and still achieving a stable level of fixed cost recovery. Second, the Company's proposed calculation of Facilities kW removes a potential impediment to qualifying customers consuming more energy during low-cost off-peak periods. There may be times when qualifying customers may want to use their lights for only a handful of off-peak hours in a fall or spring month, but will avoid doing so, because it would trigger higher facilities charges for the month. Basing the measurement on the highest two kW readings over the past year instead of each individual month's highest reading ensures that qualifying customers will not be discouraged from using additional off-peak lighting during its lowest usage months.

Q. Why did the Company shape the proposed energy charges by season and time-of-use period to match the differentials in season and time-of-use period for forecast 2020 Palo Verde wholesale prices?

A. Since Customer A and other potential indoor agricultural lighting customers have a relatively high degree of flexibility in their operations and may be able to adapt their operations to differing costs of energy, it makes sense for the differences in energy price between season and time period to vary in a way that realistically reflects cost. Palo Verde is a wholesale market hub through which the Company may transact to serve and balance its load requirements in Utah, and is therefore a good approximation of the marginal energy cost of serving load in Utah. Having the differentials in retail energy price between different times of consumption closely resemble the differential in wholesale Palo Verde prices should signal Customer A and other potential indoor agricultural lighting customers to light their crops in an economically efficient manner.

Q. Why does the Company propose revising the seasons so that May is included in the lower cost winter months?

A. The Company's current retail prices in its different tariffs are generally higher in the summer months than in the winter months, reflecting that the Company's annual system peaks occur in the summer and that wholesale energy prices are generally higher during the summer season. An examination of forecast wholesale Palo Verde prices indicates that May is one of the lowest cost months. It is therefore more appropriately included in the lower cost winter months for a new rate schedule. Table 6 below shows the differences in forecast average monthly wholesale Palo Verde prices.

Table 6. Forecast 2020 Average Monthly Wholesale Palo Verde Prices

MWh	On-Peak	Off-Peak
January	$32.73	$24.97
February	$33.65	$23.48
March	$28.64	$21.34
April	$22.98	$19.39
May	*$22.75*	*$20.23*
June	$44.83	$29.25
July	$102.03	$44.39
August	$101.16	$40.89
September	$72.28	$38.59
October	$29.36	$21.34
November	$28.92	$20.86
December	$30.83	$24.07

Q. What is the Company's proposed on-peak period for Schedule 22?

A. The proposed on-peak periods for Schedule 22 are: 3 to 9 pm during June through September, and 8 to 10 am and 3 to 9 pm during October through May. Weekends and holidays would be excluded from the on-peak hours.

Q. What is the basis for this on-peak period?

A. To determine the most appropriate on-peak period, the Company examined the timing of both system coincident and distribution coincident peaks over the last five class cost of service studies filed with the Commission. This examination showed that most peaks occurred in the late afternoon/early evening timeframe in the summer and both in the late afternoon/early evening and morning during the winter. To balance both cost causality and customer ease of use, the Company identified time periods that capture the vast majority of those peaks for both seasons. The proposed on-peak periods include the timing of 95 percent of the peaks. Exhibit No. RMP___(RMM-5) shows the hourly occurrence of peaks in the summer and winter seasons compared to the on-peak period the Company selected for proposed Schedule 22.

Q. How did the Company determine prices for secondary and primary voltage service?

A. To determine cost-based secondary and primary rates, the Company prepared two additional class cost of service studies where Customer A's loads and profile were segregated to a separate class, but assumed to be served at the secondary and primary voltage levels, the results of which are attached as Exhibit No. RMP___(RMM-6). Page 1 of Exhibit No. RMP___(RMM-6) shows that Customer A, if served at the secondary voltage level, would have revenue on Schedule 8 that would be about 6 percent less than cost of service. Page 2 of Exhibit No. RMP___(RMM-6) shows that Customer A, if served at the primary voltage level, would have revenue on Schedule 8 that would be about 13 percent less than cost of service. Table 7 below is a summary of key differences between the different class cost of service studies by voltage level.

Table 7. Summary of Differences in Cost of Service Studies by Voltage Level

Voltage Level	Energy Losses	Demand Losses	Allocation of Distribution Substations	Allocation of Distribution Poles & Conductor	Allocation of Distribution Line Transformers	Customer A's Cost of Service per MWh
Secondary	9.322%	10.106%	✓	✓	✓	$63.03
Primary	6.635%	7.377%	✓	✓		$58.64
Transmission	4.527%	4.259%				$55.98

For cost of service at the secondary voltage level, distribution line transformers, poles and conductor, and substations are allocated. For cost of service at the primary voltage level, distribution poles and conductor, and substations are allocated, but not distribution line transformers. None of these distribution facilities are allocated for cost of service at the transmission voltage level. Line losses are higher for service at the lower voltage levels. Prices for the secondary and primary voltage levels for proposed Schedule 22 were set to recover the full cost of service for Customer A as indicated in the studies prepared for it at those different voltage levels.

Conclusion

Q. Please summarize your testimony.

A. The Company's proposed Schedule 22 is in the public interest, presents cost-based rates for Customer A to consider as it potentially plans to expand its facilities in Utah, and sends appropriate price signals to other similar indoor agricultural lighting customers that are contemplating locating their operations in the Company's service territory. The lower price level from proposed Schedule 22 coupled with Customer A's expansion would represent a greater use of the Company' system and would not harm other customers. The characteristics of large indoor agricultural lighting customers are unique, beneficial, and warrant separate class treatment in the cost of service study. It

is particularly important for the Commission to make this determination and approve the Company's proposed rates at this time in light of the time sensitive opportunity related to Customer A's expansion.

Q. What is your recommendation for the Commission?

A. I recommend that the Commission approve the Company's proposed Schedule 22 for Indoor Agricultural Lighting Service.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RMM-1)
Docket No. 19-035-T06
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

Cost of Service by Rate Schedule

April 2019

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2017
2017 Protocol (Non Wgt)
7.32% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Production Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	724,698,032	7.15%	0.98	731,545,667	419,844,238	94,365,671	179,081,965	34,094,981	4,158,812	6,847,635	0.94%
2	6	General Service - Large	540,793,491	8.13%	1.11	518,575,521	363,281,433	77,758,243	73,854,482	769,269	2,912,093	(22,217,970)	-4.11%
3	8	General Service - Over 1 MW	150,124,492	7.49%	1.02	148,857,419	108,865,904	22,391,848	16,763,752	25,177	810,738	(1,267,073)	-0.84%
4	7,11,12	Street & Area Lighting	10,800,396	12.99%	1.78	8,712,080	3,170,004	492,257	4,742,756	264,600	42,463	(2,088,316)	-19.34%
5	9	General Service - High Voltage	268,430,274	5.76%	0.79	288,824,244	239,829,101	48,748,666	(301,197)	(946,583)	1,494,258	20,393,970	7.60%
6	22	Indoor Agricultural Lighting - High Voltage	1,697,474	11.92%	1.63	1,410,687	1,180,899	223,967	(3,780)	2,597	7,004	(286,787)	-16.89%
7	10	Irrigation	17,636,015	6.59%	0.90	18,361,846	12,320,695	2,520,885	3,465,704	(49,623)	104,185	725,831	4.12%
8	15	Traffic Signals	811,514	10.19%	1.39	716,446	391,981	70,957	155,478	94,481	3,549	(95,069)	-11.71%
9	15	Outdoor Lighting	1,212,971	16.98%	2.32	865,795	671,363	95,609	75,227	19,618	3,980	(347,176)	-28.62%
10	23	General Service - Small	138,084,377	8.28%	1.13	131,285,824	83,797,539	18,144,060	27,065,230	1,521,325	757,669	(6,798,553)	-4.92%
11	SpC	Customer 1	32,829,655	4.82%	0.66	37,012,270	30,629,239	6,128,028	60,567	5,726	188,710	4,182,614	12.74%
12	SpC	Customer 2	38,123,758	6.71%	0.92	39,074,650	33,301,488	5,532,033	62,586	5,360	173,184	950,893	2.49%
13		Total Utah Jurisdiction	1,925,242,448	7.32%	1.00	1,925,242,448	1,297,283,884	276,472,223	305,022,769	35,806,928	10,656,644	(0)	0.00%

Indoor Agricultural Lighting

Footnotes :

Column C : Annual revenues based on January 2017 thru December 2017 data.
Column D : Calculated Return on Ratebase per January 2017 thru December 2017 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Utah Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Rocky Mountain Power
Exhibit RMP___(RMM-2)
Docket No. 19-035-T06
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

Marginal Cost for Indoor Agricultural Lighting

April 2019

Rocky Mountain Power - State of Utah
Indoor Agricultural Lighting Schedule
Actual Load Data in 2018

Line No.	Scenarios		MWh	Revenue $000	Revenue Change vs. Actual	Revenue %	NPC Rate $/MWh	NPC $000	Wheeling Rate $/MWh	Wheeling $000	Marginal Cost $000	Marginal Cost Change vs. Actual	Marginal Cost %
	Present Size												
1	Schedule 9		25,200	$1,697	$0	0%	$18.16	$458	$0.38	$10	$1,230	$0	0%
2	New Schedule		25,200	$1,411	-$287	-17%	$18.16	$458	$0.38	$10	$943	-$287	-23%
	Larger Size	2.6											
3	New Schedule		65,520	$3,663	$1,965	116%	$18.16	$1,190	$0.38	$25	$2,448	$1,218	99%
			40,320										

Rocky Mountain Power
Exhibit RMP ___(RMM-2) Page 1 of 1
Docket No. 19-035-T06
Witness: Robert M. Meredith

Rocky Mountain Power
Exhibit RMP___(RMM-3)
Docket No. 19-035-T06
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariffs

April 2019

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~Seventh~~ Eighth Revision of Sheet No. B
P.S.C.U. No. 50 **Canceling ~~Sixth~~ Seventh Revision of Sheet No. B**

ELECTRIC SERVICE SCHEDULES
STATE OF UTAH

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

~~Seventh~~ Eighth Revision of Sheet No. B
P.S.C.U. No. 50 **Canceling ~~Sixth~~ Seventh Revision of Sheet No. B**

Issued by authority of Report and Order of the Public Service Commission of Utah in Docket No. ~~16-035-36~~19-035-~~1~~T06

FILED: ~~July 10, 2017~~April 4, 2019 **EFFECTIVE**: ~~July 20, 2017~~August 1, 2019

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Eighth Revision of Sheet No. B
P.S.C.U. No. 50 **Canceling Seventh Revision of Sheet No. B**

ELECTRIC SERVICE SCHEDULES
STATE OF UTAH

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **Original Sheet No. 22.1**

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 22

STATE OF UTAH

Indoor Agricultural Lighting Service – 1,000 kW and Over

AVAILABILITY: At any point on the Company's interconnected system where there are facilities of adequate capacity and after eligible load exceeds 30 MW.

APPLICATION: This Schedule is for alternating current, single or three-phase electric service supplied at the Company's available voltage through a single point of delivery for service to indoor agricultural lighting loads that have registered 1,000 kW or more, more than once in the preceding 18-month period. This Schedule will remain applicable until the indoor agricultural lighting load has not registered 1,000 kW or more at any time for a subsequent period of 18 consecutive months whereupon the Customer will be transferred to another appropriate schedule. If energy usage for purposes other than indoor agricultural lighting exceeds 25% of the total energy provided, the point of delivery shall be classified as not eligible for this schedule and electric service shall be provided under the appropriate general service schedule.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **Original Sheet No. 22.2**

ELECTRIC SERVICE SCHEDULE NO. 22 – Continued

MONTHLY BILL:

	Delivery Voltage		
	Secondary	**Primary**	**Transmission**
Customer Service Charge	$70.00 per Customer	$70.00 per Customer	$259.00 per Customer
Facilities Charge	$1.37 per kW	$1.37 per kW	$1.37 per kW
Power Charge			
Summer – On-Peak	$8.16 per kW	$8.05 per kW	$7.83 per kW
Summer – Off-Peak	None	None	None
Winter – On-Peak	$5.86 per kW	$5.61 per kW	$5.31 per kW
Winter – Off-Peak	None	None	None
Energy Charge			
Summer – On-Peak	9.2314 ¢ per kWh	8.8608 ¢ per kWh	8.6679 ¢ per kWh
Summer – Off-Peak	5.0770 ¢ per kWh	4.7064 ¢ per kWh	4.5134 ¢ per kWh
Winter – On-Peak	4.1108 ¢ per kWh	3.7402 ¢ per kWh	3.5473 ¢ per kWh
Winter – Off-Peak	3.4356 ¢ per kWh	3.0650 ¢ per kWh	2.8721 ¢ per kWh

SURCHARGE ADJUSTMENT: All monthly bills shall be adjusted in accordance with Schedule 80.

POWER FACTOR: This rate is based on the Customer maintaining at all times a Power Factor of 90% lagging, or higher, as determined by measurement. If the average Power Factor is found to be less than 90% lagging, the Power as recorded by the Company's meter will be increased by 3/4 of 1% for every 1% that the Power Factor is less than 90%.

CONTRACT PERIOD: One year or longer.

FACILITIES KW: Average of the two greatest non-zero monthly kW during the 12-month period which includes and ends with the current billing month as shown by or computed from the reading of Company's Power meter for the 15-minute period of Customer's greatest use at any time, adjusted for Power Factor to the nearest kW demands established.

POWER: The kW as shown by or computed from the readings of Company's Power meter for the 15-minute On-Peak period of Customer's greatest use during the month, adjusted for Power Factor to the nearest kW.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **Original Sheet No. 22.3**

ELECTRIC SERVICE SCHEDULE NO. 22.3 – Continued

TIME PERIODS:

On-Peak:	Winter months – October through May inclusive 8:00 a.m. to 10:00 a.m., and 3:00 p.m. to 9:00 p.m., Monday thru Friday, except holidays. Summer months – June through September inclusive 3:00 p.m. to 9:00 p.m., Monday thru Friday, except holidays.
Off-Peak:	All other times.

Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day, and Christmas Day. When a holiday falls on a Saturday or Sunday, the Friday before the holiday (if the holiday falls on a Saturday) or the Monday following the holiday (if the holiday falls on a Sunday) will be considered a holiday and consequently Off-Peak.

FORCE MAJEURE: Neither Company nor Customer shall be subject to any liability or damages for inability to provide or receive service to the extent that such failure shall be due to causes beyond the control of either Company or Customer, including, but not limited to the following: (a) the operation and effect of any rules, regulations and orders promulgated by any commission, municipality, or governmental agency of the United States, or subdivision thereof; (b) restraining order, injunction or similar decree of any court; (c) war; (d) flood; (e) earthquake; (f) act of God; (g) sabotage; or (h) strikes or boycotts. Should any of the foregoing occur, the minimum billing demands that would otherwise be applicable under this Schedule shall be waived and Customer will have no liability for service until such time as Customer is able to resume service.

The party claiming Force Majeure under this provision shall make every reasonable attempt to remedy the cause thereof as diligently and expeditiously as possible.

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
Exhibit RMP___(RMM-4)
Docket No. 19-035-T06
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 Indoor Agricultural Lighting Schedule Prices

April 2019

Rocky Mountain Power - State of Utah
Proposed Indoor Agricultural Lighting Schedule Prices
Actual Load Data in 2018

	Unit		Existing Price			Proposed Schedule 22					
						Transmission		Primary		Secondary	
	Sch 9	New Sch	Sch 9	Sch 8 - Pri	Sch 8 - Sec	Price	Revenue	Price	Revenue	Price	Revenue
Customer Charge (per month)	12	12	$259.00	$70.00	$70.00	$259.00	$3,108	$70.00	$840	$70.00	$840
Facilities kW (per kW-month)	111,832	180,815	$2.22	$4.76	$4.76	$1.37	$248,267	$1.65	$248,267	$1.65	$248,267
Power Charge											
Summer	(May-Sept)	(Jun-Sept)									
On-peak (per kW, for all kW)	3,710	2,820	$13.96	$14.43	$15.56	$7.83	$22,071	$8.05	$22,699	$8.16	$22,997
Off-peak			None	None	None	None		None		None	
Winter	(Oct-Apr)	(Oct-May)									
On-peak (per kW, for all kW)	64,778	66,412	$9.47	$10.06	$11.19	$5.31	$352,599	$5.61	$372,681	$5.86	$389,489
Off-peak			None	None	None	None		None		None	
Energy Charge											
Summer	(May-Sept)	(Jun-Sept)									
On-peak (per kWh, for all kWh)	490,000	276,029	$0.046531	$0.050474	$0.050474	$0.086679	$23,926	$0.088608	$24,458	$0.092314	$25,481
Off-peak (per kWh, for all kWh)	1,470,000	1,229,101	$0.029225	$0.034002	$0.034002	$0.045134	$55,474	$0.047064	$57,846	$0.050770	$62,401
Winter	(Oct-Apr)	(Oct-May)									
On-peak (per kWh, for all kWh)	6,230,000	3,659,141	$0.034989	$0.034989	$0.034989	$0.035473	$129,799	$0.037402	$136,860	$0.041108	$150,420
Off-peak (per kWh, for all kWh)	17,010,000	20,035,729	$0.029225	$0.034002	$0.034002	$0.028721	$575,443	$0.030650	$614,103	$0.034356	$688,354
							$1,410,687		$1,477,754		$1,588,250

Note:
Schedule 9 TOU: on-peak Summer: 1pm-9pm; Winter: 7am-11pm.
New Schedule: on-peak Summer: 3pm-9pm; Winter: 8am-10am, 3pm-9pm.
Facilities Charge for Schedule 22 is based upon highest two kW readings in the preceding 12 month period.

Rocky Mountain Power
Exhibit RMP ___(RMM-4) Page 1 of 1
Docket No. 19-035-T06
Witness: Robert M. Meredith

Rocky Mountain Power
Exhibit RMP___(RMM-5)
Docket No. 19-035-T06
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

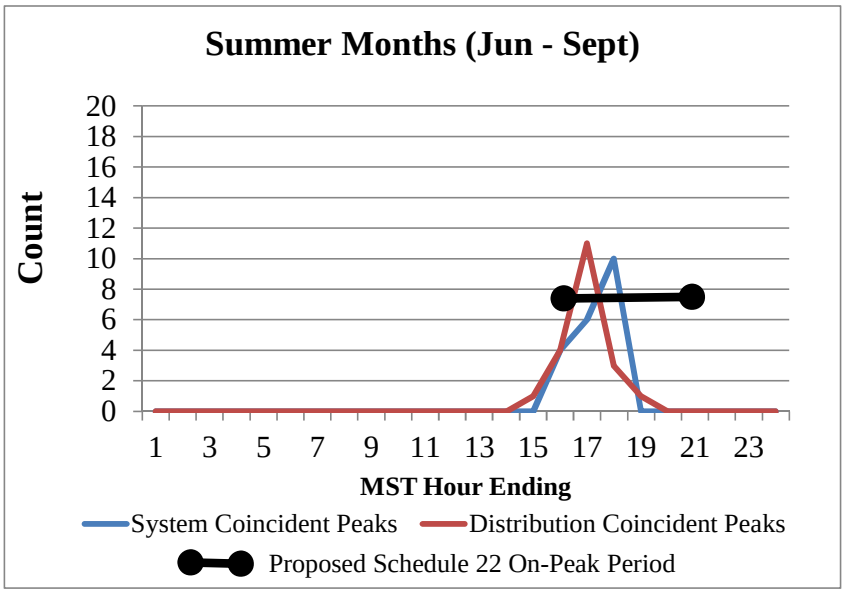
ROCKY MOUNTAIN POWER

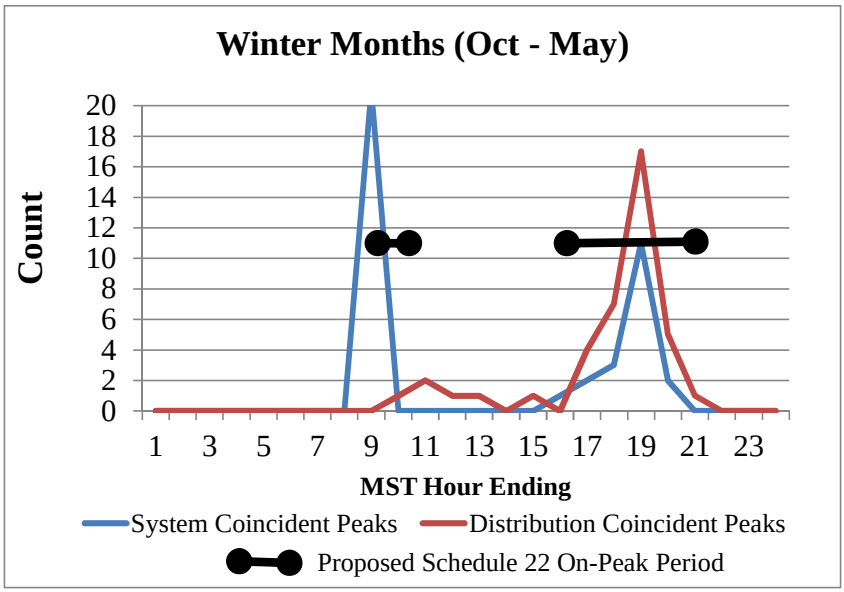
Exhibit Accompanying Direct Testimony of Robert M. Meredith

Hourly Occurrence of Peaks from Last Five Filed Cost of Service Studies

April 2019

Hourly Occurrence of Peaks from Last Five Filed Cost of Service Studies
(2013 Annual, 2014 Annual, 2015 Annual, 2016 Annual, 2017 Annual)





Rocky Mountain Power
Exhibit RMP___(RMM-6)
Docket No. 19-035-T06
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

Cost of Service Results for Secondary and Primary Service

April 2019

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2017
2017 Protocol (Non Wgt)
7.32% = Earned Return on Rate Base

A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Production Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	724,698,032	7.15%	0.98	731,495,108	419,848,940	94,365,751	179,024,908	34,097,159	4,158,349	6,797,076	0.94%
2	6	General Service - Large	540,793,491	8.13%	1.11	518,558,229	363,286,286	77,758,553	73,831,310	770,166	2,911,914	(22,235,262)	-4.11%
3	8	General Service - Over 1 MW	148,427,018	7.47%	1.02	147,338,921	107,626,211	22,155,338	16,731,474	22,777	803,122	(1,088,097)	-0.73%
4	7,11,12	Street & Area Lighting	10,800,396	12.99%	1.78	8,711,842	3,170,066	492,261	4,742,443	264,612	42,460	(2,088,554)	-19.34%
5	9	General Service - High Voltage	270,127,748	5.79%	0.79	290,239,186	241,013,830	48,972,981	(304,948)	(943,951)	1,501,274	20,111,438	7.45%
6	22	Indoor Agricultural Lighting - Secondary Voltage	1,697,474	8.72%	1.19	1,588,250	1,223,894	235,592	121,500	(1,049)	8,314	(109,224)	-6.43%
7	10	Irrigation	17,636,015	6.60%	0.90	18,360,385	12,320,862	2,520,890	3,464,020	(49,558)	104,171	724,371	4.11%
8	15	Traffic Signals	811,514	10.19%	1.39	716,440	391,987	70,958	155,465	94,482	3,549	(95,075)	-11.72%
9	15	Outdoor Lighting	1,212,971	16.98%	2.32	865,747	671,375	95,609	75,164	19,620	3,979	(347,223)	-28.63%
10	23	General Service - Small	138,084,377	8.28%	1.13	131,280,139	83,798,583	18,144,113	27,058,234	1,521,595	757,614	(6,804,238)	-4.93%
11	SpC	Customer 1	32,829,655	4.82%	0.66	37,012,815	30,629,731	6,128,078	60,569	5,726	188,711	4,183,160	12.74%
12	SpC	Customer 2	38,123,758	6.71%	0.92	39,075,385	33,302,151	5,532,100	62,588	5,360	173,186	951,627	2.50%
13		Total Utah Jurisdiction	1,925,242,448	7.32%	1.00	1,925,242,448	1,297,283,915	276,472,224	305,022,725	35,806,939	10,656,644	(0)	0.00%

Indoor Agricultural Lighting

Footnotes :

Column C : Annual revenues based on January 2017 thru December 2017 data.
Column D : Calculated Return on Ratebase per January 2017 thru December 2017 Embedded Cost of Service Study
Column E : Rate of Return Index. Rate of return by rate schedule, divided by Utah Jurisdiction's normalized rate of return.
Column F : Calculated Full Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study
Column G : Calculated Generation Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column H : Calculated Transmission Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column I : Calculated Distribution Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column J : Calculated Retail Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column K : Calculated Miscellaneous Cost of Service at Jurisdictional Rate of Return per the January 2017 thru December 2017 Embedded COS Study.
Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

Rocky Mountain Power
Cost Of Service By Rate Schedule
State of Utah
12 Months Ended Dec 2017
2017 Protocol (Non Wgt)
7.32% = Earned Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Production Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	724,698,032	7.15%	0.98	731,545,646	419,844,296	94,365,709	179,081,866	34,094,963	4,158,812	6,847,615	0.94%
2	6	General Service - Large	540,793,491	8.13%	1.11	518,575,507	363,281,485	77,758,276	73,854,384	769,269	2,912,093	(22,217,984)	-4.11%
3	8	General Service - Over 1 MW	148,427,018	7.46%	1.02	147,379,688	107,655,580	22,161,232	16,736,925	22,607	803,343	(1,047,331)	-0.71%
4	7,11,12	Street & Area Lighting	10,800,396	12.99%	1.78	8,712,076	3,170,005	492,257	4,742,751	264,600	42,463	(2,088,320)	-19.34%
5	9	General Service - High Voltage	270,127,748	5.79%	0.79	290,234,961	241,010,028	48,972,610	(304,987)	(943,951)	1,501,262	20,107,212	7.44%
6	22	Indoor Agricultural Lighting - Primary Voltage	1,697,474	10.63%	1.45	1,477,754	1,210,061	230,488	27,243	2,565	7,396	(219,720)	-12.94%
7	10	Irrigation	17,636,015	6.59%	0.90	18,361,837	12,320,697	2,520,886	3,465,692	(49,623)	104,185	725,822	4.12%
8	15	Traffic Signals	811,514	10.19%	1.39	716,446	391,981	70,957	155,478	94,481	3,549	(95,068)	-11.71%
9	15	Outdoor Lighting	1,212,971	16.98%	2.32	865,795	671,363	95,609	75,227	19,618	3,980	(347,176)	-28.62%
10	23	General Service - Small	138,084,377	8.28%	1.13	131,285,810	83,797,551	18,144,068	27,065,199	1,521,323	757,669	(6,798,567)	-4.92%
11	SpC	Customer 1	32,829,655	4.82%	0.66	37,012,274	30,629,243	6,128,031	60,565	5,726	188,710	4,182,619	12.74%
12	SpC	Customer 2	38,123,758	6.71%	0.92	39,074,655	33,301,493	5,532,035	62,584	5,360	173,184	950,897	2.49%
13		Total Utah Jurisdiction	1,925,242,448	7.32%	1.00	1,925,242,448	1,297,283,781	276,472,157	305,022,927	35,806,939	10,656,644	(0)	0.00%

Indoor Agricultural Lighting

Footnotes :

Column C : Annual revenues based on January 2017 thru December 2017 data.
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Column L : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Dollars.
Column M : Increase or Decrease Required to Move From Annual Revenue to Full Cost of Service Percent.

CERTIFICATE OF SERVICE

Docket No. 19-035-T06

I hereby certify that on April 4, 2019, a true and correct copy of the foregoing was served by electronic mail to the following:

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Katie Savarin
Coordinator, Regulatory Operations