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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.	**Docket No. 20-035-04**

PREFILED REBUTTAL TESTIMONY AND EXHIBITS OF

JUSTIN BIEBER

The Utah Association of Energy Users ("UAE") hereby submits this Prefiled Rebuttal Testimony of Justin Bieber in this docket.

DATED this 16th day of October 2020.

JAMES DODGE RUSSELL & STEPHENS

By: Phillip J Russell
Phillip J. Russell
Counsel for the Utah Association of Energy Users

CERTIFICATE OF SERVICE
Docket No. 20-035-04

I hereby certify that a true and correct copy of the foregoing was served by email this 16th day of October 2020 on the following:

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.	**Docket No. 20-035-04**

REBUTTAL TESTIMONY AND EXHIBITS OF

JUSTIN BIEBER

On Behalf of the

Utah Association of Energy Users

October 16, 2020

REBUTTAL TESTIMONY OF JUSTIN BIEBER

Introduction

Q. Please state your name and business address.

A. My name is Justin Bieber. My business address is 111 E Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. Are you the same Justin Bieber who pre-filed direct testimony in the cost-of-service phase of this docket on behalf of the Utah Association of Energy Users ("UAE")?

A. Yes, I am.

Overview and Conclusions

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony of the Utah Office of Consumer Services ("Office") witness Ron Nelson and the Division of Public Utilities ("Division") witness Bruce R. Chapman.

Q. Please summarize your recommendations to the Commission.

I recommend that the Commission disregard the results of Office witness Mr. Nelson's alternative embedded cost of service study ("ECOSS"). Although Mr. Nelson declines to provide a specific rate spread recommendation in his direct testimony,[1] he nevertheless recommends that the Commission consider his

[1] Direct Testimony of Ron Nelson, p. 58.

modified ECOSS results to inform the rate spread between customer classes.[2] Mr. Nelson's modified ECOSS incorporates three changes to the ECOSS cost allocation methodology that are unsubstantiated and significantly skew the results of the study. Specifically, Mr. Nelson proposes the following changes:

1. He proposes to change the classification of production and transmission from 75% demand-related and 25% energy-related to 40% demand-related and 60% energy-related;
2. He proposes to increase the proportion of distribution plant that is considered primary by 10%; and
3. He proposes to re-functionalize metering costs as 1/3 production, 1/3 transmission, and 1/3 distribution.[3]

Mr. Nelson's proposed modification to re-classify production and transmission plant as 40% demand-related and 60% energy-related is arbitrary, and he does not provide any evidence that this modification would more accurately represent the Company's production and transmission assets. It would also represent a significant departure from the long-standing practice and past Commission precedent in Utah on this issue. Similarly, Mr. Nelson does not provide any evidence to support his proposal to re-functionalize distribution plant by increasing the amount of primary distribution plant by 10% while reducing the sub-functionalization of secondary distribution plant by the same amount. Further,

[2] Id, p. 50.
[3] Id, p. 49.

Mr. Nelson's proposal to functionalize meter costs as 1/3 production, 1/3 transmission, and 1/3 distribution is not aligned with cost causation.

Division witness Bruce Chapman explains that the method that Rocky Mountain Power ("RMP") proposes to use in its ECOSS for the classification of distribution costs is different from the common industry practice. RMP classifies meters and service lines as customer-related while all other distribution costs are classified as entirely demand-related. This method differs from common industry practice because it does not recognize the fact that much of the distribution system, including poles, underground conduit, conductors, and transformers, have both demand-related and customer-related components. Mr. Chapman identifies two alternative approaches outlined in the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual"), the "Minimum Size Method" and the "Minimum-Intercept Method," that properly recognize that much of the distribution system has both demand-related and customer-related properties.[4] To the extent that the Commission considers changes to RMP's ECOSS methodologies, I recommend that it direct RMP to utilize one of the two methods identified by Mr. Chapman as outlined in the NARUC Manual, which would properly recognize the fact that these distribution costs have both a customer-component and demand-related component.

[4] Direct Testimony of Bruce R. Chapman, pp. 12-13.

<u>Response to Office Witness Ron Nelson</u>

Q. Please explain the alternative ECOSS model presented by Office witness Ron Nelson.

A. Mr. Nelson provides an alternative ECOSS model that proposes three modifications to RMP's ECOSS. Mr. Nelson's first modification would change the classification of production and transmission from 75% demand-related and 25% energy-related to 40% demand-related and 60% energy-related. In Mr. Nelson's second modification, he makes an adjustment to the sub-functionalization of distribution plant to increase the amount of distribution plant in certain FERC accounts that is sub-functionalized as primary by 10%. Mr. Nelson's third modification would re-functionalize meter costs as 1/3 production, 1/3 transmission, and 1/3 distribution.[5]

Q. Please summarize the results of Mr. Nelson's alternative ECOSS.

A. Mr. Nelson's modifications to the ECOSS result in very significant changes relative to the Company's proposed study. These alternative results indicate that the cost of service deficiency for the Residential class would be decreased by ~5.5%, while the costs for all other classes, except General Service – Small, would be increased by varying amounts. The resulting differences in the cost of service for some customer classes would be very significant if Mr. Nelson's proposed changes were to be adopted. Table JDB-1R below summarizes the results of Mr. Nelson's alternative ECOSS model and compares it to RMP's proposed ECOSS.

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[5] Direct Testimony of Ron Nelson, p. 49.

Table JDB-1R
Office Alternative ECOSS Results Relative to RMP's Proposed ECOSS
At RMP's Proposed Revenue Requirement

Customer Class	RMP ECOSS % Change to = ROR	Office ECOSS % Change to = ROR	Office ECOSS Increase/(Decrease)
Residential	12.8%	7.3%	-5.5%
Commercial and Industrial			
Schedule 23	-4.5%	-5.7%	-1.2%
Schedule 6	-2.6%	-1.5%	1.1%
Schedule 8	-0.6%	3.6%	4.2%
Schedule 9	7.2%	13.9%	6.7%
Irrigation	5.7%	12.2%	6.5%
Lighting Schedules	-21.9%	-13.7%	8.3%
Overall System Average	**4.8%**	**4.8%**	

Q. Does Mr. Nelson recommend that his alternate ECOSS be considered to inform the rate spread between customer classes?

A. Yes, he does.[6] However, Mr. Nelson does not offer a specific rate spread recommendation in his direct testimony. He explains that he plans to provide a rate spread recommendation in surrebuttal testimony that will allow him to factor into his analysis whether the revenue requirement differences have narrowed and evaluate any updated data that RMP provides.[7]

Q. What is your assessment of Mr. Nelson's alternative ECOSS?

A. I have significant concerns with Mr. Nelson's proposed modifications to the ECOSS. He does not provide any evidence to support his proposed

[6] Id, p. 50.
[7] Id, p. 58.

modification to classify production and transmission as 40% demand-related and 60% energy-related or to support his modification to increase the amount of distribution plant sub-functionalized as primary by 10%. Further, Mr. Nelson's proposed re-functionalization of meter costs is not aligned with cost causation principles. Viewed singly, and as a whole, each of his three changes appear to be solely intended to shift costs away from residential customers onto other customer classes, without any basis in cost causation. I will address each of these proposed modifications below.

Q. Mr. Nelson states that he is waiting to provide a rate spread recommendation until surrebuttal testimony so that he can factor revenue requirement differences and updated data into his recommendation.[8] How do you respond?

A. Since Mr. Nelson has not offered a recommendation on rate spread at this time, I cannot provide a direct response. But it seems to me that his strategy of withholding a recommendation until he files his surrebuttal testimony places other parties at an unfair disadvantage, in that there is no opportunity for parties to respond to his proposal in prefiled testimony. His justification for holding back on presenting a recommendation until more is known about revenue requirement differences is unpersuasive, as parties, including the Office, made their revenue requirement recommendations known one week prior to Mr. Nelson's testimony filing. These concerns notwithstanding, I will demonstrate that Mr. Nelson's

[8] Id.

alternative ECOSS is unsubstantiated and should not be relied upon to inform the rate spread between customer classes.

Classification of Production and Transmission Costs

Q. How does the Company allocate production and transmission costs in its ECOSS?

A. As I explain in my direct testimony, the Company's proposed ECOSS classifies production and transmission plant as 75% demand-related and 25% energy-related.[9] The demand-related portion is allocated using the 12-monthly peaks ("12 CP") coincident with the Company's total system firm peak.[10]

Q. Please describe Mr. Nelson's concerns with RMP's proposed classification of production costs.

A. Mr. Nelson explains that he is concerned with the fact that RMP's classification of production as 75% demand-related and 25% energy-related treats all production resources the same, regardless of whether it is a solar facility, gas turbine, or coal generator. According to Mr. Nelson, this fails to acknowledge that investment in different resources reflects specific needs on the power system. He therefore concludes that RMP should not classify production costs uniformly without evaluating the specific mix of production plant resources on its system.[11]

[9] *See* Direct Testimony of Justin Bieber, p. 5.
[10] Direct Testimony of Robert M. Meredith, p. 7.
[11] Direct Testimony of Ron Nelson, pp. 28-29.

Q. How does Mr. Nelson recommend that RMP classify production plant?

A. Mr. Nelson asserts that there are several classification approaches presented in industry literature that he believes would more specifically and accurately classify RMP's production costs to align with its planning needs and data. According to Mr. Nelson, the Probability of Dispatch method is superior to most other methods because it allows for time-differentiated cost allocation. He also claims that the Equivalent Peaker method is one of the more reasonable approaches.[12]

Q. Does Mr. Nelson perform any analyses of the alternative production and transmission cost allocation methods that he recommends, such as the Probability of Dispatch or Equivalent Peaker methods?

A. No, he does not. Mr. Nelson explains that given the Commission's previous rulings, he determined not to conduct those analyses.[13] However, he does provide a sensitivity analysis which he includes in his alternative ECOSS study that modifies the production and transmission classification from 75% demand-related and 25% energy-related to 40% demand-related and 60% energy-related. Mr. Nelson explains that his sensitivity analysis is intended to "demonstrate that higher demand-related classification imposes more costs on residential customers."[14]

[12] Id, pp. 36-37.
[13] Id, p. 37.
[14] Id, pp. 33-34.

Q. As you explain above, Mr. Nelson asserts that "RMP should not classify production costs uniformly without evaluating the specific mix of production plant resources on its system."[15] Does Mr. Nelson perform an evaluation of RMP's specific mix of production plant resources to support his proposed modification to classify production plant as 40% demand-related and 60% energy-related?

A. No, he does not. Although Mr. Nelson claims that the 75% demand-related and 25% energy-related split does not appropriately reflect certain categories of generation units in RMP's production fleet,[16] he does not provide any evidence to support his statement that a 40% demand-related and 60% energy-related split better reflects cost causation. In response to discovery on this topic, the Office confirms that Mr. Nelson did not perform any quantitative analysis of RMP's generation portfolio to support this statement. Instead, Mr. Nelson relied on his own qualitative analysis of production related information within the ECOSS.[17]

Q. What is your assessment of Mr. Nelson's proposed modification to classify production plant as 40% demand-related and 60% energy-related?

A. Mr. Nelson does not provide any quantitative evidence to show that his proposed 40% demand-related and 60% energy-related split is appropriate and his reliance on his own "qualitative" analysis of production related information is subjective. He asserts that RMP should not classify production costs uniformly

[15] Id, p. 29.
[16] Id, p. 34.
[17] Office Response to UAE Data Request 1.2, Reproduced in UAE Exhibit COS 4.1, attached hereto.

without evaluating the specific mix of production resources on the system, yet he proposes an alternative classification without performing any quantitative analysis himself.

Further, Mr. Nelson's proposed 40% demand-related and 60% energy-related split is inconsistent with his own recommendations regarding an appropriate production cost allocation methodology. He claims that he is concerned with RMP's cost allocation methodology because it treats all production resources the same, yet his proposed modification would also treat all production resources the same. He also asserts that other production cost allocation methods such as the Probability of Dispatch and Equivalent Peaker are more reasonable cost allocation methods, although he does not conduct any analyses on those cost allocation methodologies.

Given Mr. Nelson's lack of evidence and analyses to support his proposed modification, and considering his own claims that other cost allocation methods would actually be more reasonable, I disagree that Mr. Nelson's "sensitivity analysis" utilizing a 40% demand-related and 60% energy-related weighting for production allocation should be considered to inform the rate spread between customer classes in this case.

Q. Do you have any other concerns with Mr. Nelson's proposed modification to classify production plant as 40% demand-related and 60% energy-related?

A. Yes, I do. Mr. Nelson's proposed modification would be a significant departure from RMP's long-standing practice and Commission precedent in Utah on this issue. Further, it would not be consistent with the Company's inter-jurisdictional cost allocation methodology for production costs to the Utah jurisdiction. This would result in a misalignment between the cost causation contribution of each customer class towards the Utah system inter-jurisdictional allocation of production costs and the allocation of production costs to that class in the ECOSS.

Q. Has the Commission previously provided guidance on the standard of review for advocating alternative production cost allocation methods?

A. Yes, it has. In RMP's 2009 general rate case, the Commission approved the Company's use of the 75% demand-related and 25% energy-related classification and rejected allocation methods proposed by other parties, including the Office. In doing so, the Commission cited three reasons for using the 75% demand-related and 25% energy-related classification: 1) it "recognizes the design capability of meeting both peak demand and to generate lower cost energy"; 2) "the Commission has previously decided that this classification is reasonable"; and 3) "no other thorough analysis has been submitted that supports a change from the current classification split."[18]

As Mr. Nelson points out,[19] the Commission went on to note in that order that "[a]ny party who would like to propose an alternative to the approved methods must provide analysis to demonstrate the proposed method is also

[18] Docket No. 09-035-23, Rocky Mountain Power 2009 General Rate Case, Phase I Order on Revenue Requirement and Cost of Service using June 2010 Forecast Test Period, February 18, 2010, ("2009 Phase I Order") at 122.
[19] Direct Testimony of Ron Nelson, p. 31.

appropriate and viable at the interjurisdictional level. This analysis must include a level of detail to determine the impacts to Utah and other states in the PacifiCorp system of a proposed change in classification and allocation methods."[20]

Q. Does Mr. Nelson provide any analysis to demonstrate that his proposed 40% demand-related and 60% energy-related production classification methodology would be appropriate at the inter-jurisdictional level?

A. No, he does not. Mr. Nelson claims that since the 2020 Protocol is moving away from dynamic allocations toward fixed allocations, that would appear to obviate the need for such analysis because RMP is moving towards a state-specific allocation approach.[21]

Q. How do you respond to Mr. Nelson's claim that the 2020 Protocol obviates the need for any analysis that his proposed 40% demand-related and 60% energy-related production classification methodology would be appropriate at the inter-jurisdictional level?

A. My reading of the 2020 Protocol indicates that it will continue to use the current inter-jurisdictional system generation factors that classify production resources as 75% demand-related and 25% energy-related through the Interim Period,[22] which will likely extend through December 31, 2023.[23] Given that the current inter-jurisdictional methodology will likely be in place for three years

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[20] 2009 Phase I Order at 123.
[21] Direct Testimony of Ron Nelson, pp. 31-32.
[22] Docket No. 19-035-42, Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement, Exhibit RMP__(JRS-1), p. 10.
[23] Id, p. 8.

after the effective date of this case, this current methodology is clearly still a relevant consideration in this case.

Moreover, my reading of the 2020 Protocol is that the fixed costs of existing resources allocated to Utah after the interim period will be based on an average of the system generation factors from the prior four years.[24] Thus, costs will likely be incurred by Utah as a jurisdiction for the foreseeable future based on a production classification methodology that closely mirrors the current 75% demand-related and 25% energy-related classification. Any change to the current production classification methodology for intra-class allocations in RMP's ECOSS would create a mismatch between cost causation and cost allocation. Mr. Nelson's proposed production classification methodology in this case is inconsistent with cost causation resulting from an inter-jurisdictional cost allocation method agreed to by the Office and the other parties in the 2020 Protocol, both before and after December 31, 2023.

Q. Are there any commonly accepted energy weighted production cost allocation methods that could reasonably utilize a higher energy weighting?

Yes. The Average and Excess ("A&E") production allocation method is a well-established and commonly accepted energy weighted cost allocation method that can properly be used to allocate a utility's entire generation fleet. The A&E method, as described in the NARUC Manual, allocates production plant based on the average energy use and a measure of <u>excess</u> demand. Excess demand is equal

[24] Id, p. 100.

to peak demand less average demand. According to the manual, the energy weighting is equal to the system load factor and the excess demand weighting is equal to one minus the system load factor.[25]

It is important to understand that the appropriate weightings of energy and demand components differ depending on the cost allocation method that is used. Structurally, there are some similarities between the A&E method and RMP's proposed classification of production as 75% demand-related and 25% energy-related in that they are both energy weighted cost allocation methodologies. However, one important difference between RMP's method and the A&E method is that the former utilizes a measure of peak demand, while the latter uses a measure of excess demand. Given this key difference, it is not appropriate to "mix and match" the energy and demand weightings between these two methods.

Q. What is your recommendation if the Commission does determine it is appropriate to modify its past precedent regarding production cost allocation in RMP's ECOSS?

A. As I stated in my direct testimony, I am not recommending any changes to the current 75% demand-related and 25% energy-related production allocation method in RMP's ECOSS. However, to the extent that the Commission determines it is reasonable to increase the energy component weighting for the classification of production costs, then it should also utilize the A&E cost allocation method

[25] National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual, pp. 49-50.

which more appropriately utilizes a measure of excess demand to allocate capacity costs.

Sub-Functionalization of Primary and Secondary Distribution Costs

Q. Please describe Mr. Nelson's concerns regarding the sub-functionalization of distribution costs between primary and secondary for FERC Accounts 364-368.

A. Mr. Nelson claims that RMP does not explain in testimony its methodology for determining whether distribution infrastructure is primary or secondary, and that in response to discovery RMP failed to explain its methodology and its data. According to Mr. Nelson, without a transparent quantitative explanation of the costs, there is no way to know whether RMP's primary/secondary split calculations are accurate.[26]

Q. Please explain Mr. Nelson's proposed adjustment to the sub-functionalization of primary and secondary distribution plant which he includes in is his alternative ECOSS.

A. Mr. Nelson explains that because RMP did not meet its burden to demonstrate the split of secondary and primary distribution, he provides an adjustment in his alternative ECOSS to increase the proportion of distribution plant in FERC accounts 365, 366, and 367 that is sub-functionalized to primary by 10%.

[26] Direct Testimony of Ron Nelson, pp. 25-26.

Q. Does Mr. Nelson provide any evidence that indicates that his adjustment to increase the proportion of distribution plant that is sub-functionalized as primary is accurate?

A. No, he does not. Mr. Nelson does not provide any evidence in his direct testimony to show that this 10% adjustment more accurately represents RMP's distribution plant. In response to discovery, the Office explains that the reason Mr. Nelson does not provide any evidence is because he did not have data available to calculate an alternative.[27]

Q. Does Mr. Nelson explain why he only includes a 10% adjustment for distribution plant in FERC accounts 365, 366, and 367, but does not include an adjustment to FERC Account 364 or 368?

A. No. Mr. Nelson explains his concern that RMP does not provide sufficient evidence regarding the sub-functionalization of distribution costs between primary and secondary for FERC Accounts 364-368, but he only includes FERC Accounts 365-367 in his proposed adjustment.[28]

Q. How is the distribution plant in FERC Account 368 sub-functionalized between primary and secondary in RMP's ECOSS?

A. RMP's ECOSS sub-functionalizes all distribution plant in FERC Account 368 Line Transformers as secondary. According to the Company's cost of service

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[27] Office Response to UAE Data Request 1.1, Reproduced in UAE Exhibit COS 4.1, attached hereto.
[28] Direct Testimony of Ron Nelson, pp. 25-27.

procedures, only customers taking service at secondary voltage are allocated transformer costs.[29]

Q. What proportion of distribution plant in FERC Account 364 is sub-functionalized as primary in RMP's ECOSS?

A. RMP's ECOSS sub-functionalizes 99.86%, or virtually all, of the distribution plant in FERC Account 364 Poles, Towers, and Fixtures as primary distribution plant.[30]

Q. What is your assessment of Mr. Nelson's sensitivity analysis that increases the sub-functionalization of primary plant in FERC Accounts 365 through 367 by 10%?

A. Mr. Nelson provides absolutely no evidence to indicate that his proposed sensitivity analysis would result in a more accurate allocation of RMP's distribution plant. Further, he selectively excludes FERC Account 364, for which 99.86% of distribution plant is already sub-functionalized as primary, from his proposed adjustment.

Despite the alleged lack of evidence from RMP regarding the split between primary and distribution plant, basic logic would indicate that at least some amount of poles, towers, and fixtures in FERC Account 364 should be considered secondary, especially given that there is a substantial amount of secondary plant in FERC Account 365 for overhead conduit and devices. It would be more appropriate to include an adjustment to FERC Account 364 to re-

[29] Exhibit RMP__(RMM-3), p. 8.
[30] Id, p. 180.

functionalize some reasonable amount of distribution plant in this account as secondary, before any arbitrary and unsubstantiated adjustments are made to re-functionalize distribution plant in other FERC accounts.

Functionalization of AMI Costs

Q. How does RMP treat meter costs in its ECOSS?

A. In RMP's ECOSS, meters are included in the distribution function and classified as customer-related. The meter allocation factor is developed using the installed costs of new metering equipment for different types of customers.[31] For example, RMP's average meter cost per Schedule 1 customer is $111, while the average meter cost per Schedule 9 customer is $22,612.[32]

Q. How does Mr. Nelson recommend that meter costs should be treated in the ECOSS?

A. Mr. Nelson recommends that metering costs should be functionalized as 1/3 production, 1/3 transmission, and 1/3 distribution. He claims that Advanced Metering Infrastructure ("AMI") capabilities can create benefits by avoiding energy and demand-related costs and therefore should be allocated similarly to production and transmission costs.[33] According to Mr. Nelson, traditional cost causation would indicate that the customer who needs a meter incurs the meter cost and therefore should pay for all of it. However, he asserts that the principle

[31] Direct Testimony of Robert M. Meredith, p. 7.
[32] Exhibit RMP__(RMM-3), p. 171.
[33] Direct Testimony of Ron Nelson, p. 42.

of "beneficiary pays" better accommodates AMI costs and benefits because it recognizes that those who benefit from the cost are not always those who cause it.[34]

Q. How do you respond to Mr. Nelson's recommendation?

A. I recommend that the Commission reject Mr. Nelson's proposal to re-functionalize meter costs as 1/3 production, 1/3 transmission, and 1/3 distribution. I agree with Mr. Nelson's statement that traditional cost causation principles indicate that the customer who needs the meter incurs the meter cost and therefore should pay for it. However, I find Mr. Nelson's "beneficiary pays" logic to be flawed in this case.

To the extent that certain customer classes leverage the benefits of AMI to reduce costs on the system by reducing their coincident peaks, that will reduce the costs that would be allocated to that customer class in an ECOSS. Similarly, customers that utilize AMI to provide demand response would be compensated for the demand response that they provide. Thus, the same customers causing the AMI costs would also be the beneficiaries.

While it is possible that there may be some production and transmission investments that can be avoided or deferred due to changing customer behavior, those are hypothetical avoided costs. However, an *embedded* cost of service study allocates actual embedded costs, not hypothetical avoided costs.

[34] Id, p. 19.

<u>Response to Division Witness Bruce Chapman</u>

Classification of Distribution Costs

Q. What issue does Division witness Bruce Chapman identify with respect to RMP's classification of distribution costs?

A. RMP classifies distribution meters and service lines as customer-related, while all other distribution costs are considered demand-related. Mr. Chapman explains that this approach is different from common industry practice for costs other than those related to services and meters and substations. The standard practice acknowledges that much of the distribution system, including poles, underground conduit, conductors, and transformers, have both demand-related and customer-related properties that should be reflected in the classification methodology.[35]

Q. According to Mr. Chapman, what are the standard distribution classification methodologies?

A. Mr. Chapman explains that the NARUC Manual identifies two approaches. The "Minimum Size Method" classifies a hypothetical distribution system that services all accounts but only at minimum load as customer-related, with the residual cost considered demand-related. The second approach is the "Minimum-Intercept Method" that statistically analyzes each component of the existing system by regressing equipment size or capacity on cost to determine the zero-capacity cost per unit for the component. The number of units multiplied by

[35] Direct Testimony of Bruce R. Chapman, pp. 12-13.

this cost yields the customer-related share of cost, while the residual is demand-related.[36]

Q. What does Mr. Chapman recommend regarding the classification of distribution costs?

A. Mr. Chapman infers that RMP would strengthen its ECOSS methodology by producing a methodological defense of its approach to classifying distribution costs or by investigating whether one of the approaches identified in the NARUC Manual would improve its classification procedure for distribution costs.

Q. What is your assessment of Mr. Chapman's recommendation regarding the classification of distribution costs?

A. RMP's practice of classifying all distribution costs, other than those related to services and meters, as entirely demand-related is inconsistent with cost causation. Specifically, the classification of all distribution plant in accounts 364 through 368 solely as demand-related fails to recognize that a significant portion of the investment in these facilities is primarily related to the number of customers. The Minimum Size Method or Minimum-Intercept Method that Mr. Chapman describes would properly allocate those customer-related costs in alignment with cost causation.

[36] Id, p. 13.

Q. What do you recommend regarding the classification of distribution costs in this case?

A. To the extent that the Commission considers any modifications to RMP's ECOSS methodologies in this case, then it should direct RMP to adopt a commonly accepted distribution classification methodology such as the Minimum Size Method or Minimum-Intercept Method.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.