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Witness: Timothy S. Lyons
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Before the Public Service Commission
of the State of Missouri

Rebuttal Testimony

of

Timothy S. Lyons

on Behalf of

The Empire District Electric Company
A Liberty Utilities Company

March 2020

Liberty Utilities
EMPIRE DISTRICT

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TIMOTHY S. LYONS
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
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REBUTTAL TESTIMONY OF TIMOTHY S. LYONS ON BEHALF OF THE EMPIRE DISTRICT ELECTRIC COMPANY BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts, 01581.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. ARE YOU THE SAME TIMOTHY S. LYONS WHO PREVIOUSLY SPONSORED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am. I sponsored direct testimony ("Direct Testimony") on behalf of The Empire District Electric Company ("Empire" or the "Company") before the Missouri Public Service Commission (the "Commission").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this rebuttal testimony is to address recommendations by the Staff of the Commission ("Staff") in their class cost of service report related to the Company's proposed class cost of service study and rate design. In addition, this rebuttal testimony will address recommendations by Kavita Maini representing Midwest Energy Consumers Group ("MECG") in her direct testimony related to the Company's proposed class cost of service study and rate design.

III. SUMMARY OF STAFF AND MECG'S RECOMMENDATIONS

Q. PLEASE SUMMARIZE STAFF'S RATE DESIGN AND COST ALLOCATION RECOMMENDATIONS.

A. Staff's recommendations are summarized below.

1. Implement the Sales Reconciliation to Levelized Expectations ("SRLE") mechanism to account for the impact of weather and conservation on Schedules Residential General ("RG"), Commercial Service ("CB") and Space Heating ("SH") revenues.[1] The SRLE mechanism is similar to the Volumetric Indifference Reconciliation to Normal ("VIRN") mechanism that was recently approved in Ameren Missouri's gas rate case in Case No. GR-2019-0077.
2. Consolidate the customer charge, head block and summer tail block rates for Schedules CB and SH, while maintaining distinct tail block rates for each schedule.[2] Staff believes it is not unreasonable to maintain distinct winter tail block rates for Schedule SH customers to ensure they do not over-contribute to the cost of maintaining the transmission and distribution system.

[1] Staff's Class Cost of Service Report, pg. 3.
[2] Ibid., pg. 16.

3. Consolidate Schedule General Power ("GP") and Total Electric Building ("TEB") rates.[3] Staff believes there are no apparent cost-related differences to maintain separate rate schedules.
4. Consolidate in a future rate case proceeding Schedule Feed Mill and Grain Elevator Service ("PFM") into the consolidated Schedules GP and TEB.[4] Staff encourages the Company to work one-on-one with customers on Schedule PFM in transition to the consolidated rate schedule.
5. Set class revenue requirements based on the following process:
    a. Reduce class revenue requirements by the level of the temporary tax reduction, and;
    b. Reduce consolidated Schedules CB and SH, Schedule LP and consolidated Schedules GP and TEB revenues by 25.0 percent, 25.0 percent and 50.0 percent, respectively, of the revenue reduction available after the temporary tax reduction.[5]
6. Design rates based on the following process:
    a. Maintain Schedule RG customer charge of $13.00 per month and apply the revenue reduction to the energy (kWh) rates in a uniform manner.[6]
    b. Maintain consolidated Schedules CB and SH customer charge at $22.69 per month and apply the revenue reduction to the energy (kWh) rates in a uniform manner, except Schedule CB's winter tail block rate should be

[3] Staff report, pg. 18.
[4] Staff report, pg. 20.
[5] Staff report, pg. 2.
[6] Staff report, pg. 2.

reduced by two-thirds of the overall percentage reduction, and Schedule SH's winter tail block rate should be reduced by one-half of the Schedule CB's winter tail block rate reduction.[7]

c. Apply consolidated Schedules GP and TEB and Schedule LP's revenue reductions to all rates, including the customer charge, in a uniform manner.[8]

d. Maintain Schedule PFM at its pre-tax reduction rates.[9]

e. Revise Schedule Special Transmission Service Contract's ("SC-P") on-peak, off-peak, and shoulder energy rates to better reflect market energy prices during these periods.[10]

7. Revise the class cost of service study to reflect the following:

a. Allocate production-related costs utilizing the highest 100 hours of peak load for each class.

b. Classify distribution plant accounts 364, 366, and 368 based on a zero-intercept study that estimates a portion of plant based on the zero-intercept method.[11]

c. Allocate primary distribution plant facilities based on sum of each class's coincident peak demands at primary voltage levels.[12]

d. Allocate service lines and meter costs using the number of meters instead of the number of customers.[13]

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[7] Staff report, pgs. 16-17
[8] Staff report, pgs. 19-20.
[9] Staff report, pg. 19-21.
[10] Staff report, pgs. 21-23.
[11] Staff report, pgs. 27-29.
[12] Staff report, pg. 29.
[13] Staff report, pg. 30

e. Allocate General Plant and Administrative and General ("A&G") expenses based on an energy sales allocator.[14]

Q. PLEASE SUMMARIZE MECG'S RATE DESIGN AND COST ALLOCATION RECOMMENDATIONS

A. MECG's recommendations are summarized below.

1. Set class revenue requirements to reflect a revenue neutral adjustment for Schedule RG to align with the class cost of service.
2. Revise the allocation of the cost of Schedule SC-P interruptible credits.
3. Firm-up current interruptible revenues to properly match the cost allocation of production costs.
4. Make corrections to the SC-P class rate design.
5. Apply any Schedule LP rate increase to the billing demand and facility charges, after adjusting the customer charge as proposed by the Company. Apply any Schedule LP rate decrease to the energy charge to correct the over-recovery of fixed costs from energy charges.
6. Revise the class cost of service study to reflect the following:
    a. Allocate production-related costs utilizing the Average & Excess (A&E) method utilizing 3 summer and 3 winter month non-coincidental demand.
    b. Allocate primary and secondary distribution plant facilities utilizing a single non-coincident peak allocator.

[14] Staff Class Cost of Service Study Workpapers

c. Firm-up interruptible revenues to properly match with cost allocation of all fixed production plant.

d. Allocate the cost of the economic development rider on revenues pursuant to SB 564.

Q. PLEASE SUMMARIZE THE COMPANY'S RESPONSE TO STAFF AND MECG'S RECOMMENDATIONS.

A. The Company's response to Staff and MECG's recommendations is summarized below.

1. The Company appreciates Staff's concerns regarding the proposed WNR and would be willing to consider revisions to the proposal, such as: (a) calculation of the weather adjustment on a calendar year basis rather than on a monthly basis; and (b) implementation of the WNR as a "Pilot Program" subject to evaluation by the Commission, Staff and other key stakeholders. The revisions would create a mechanism more aligned with the Weather Normalization Adjustment Rider ("WNAR"), which has been approved by the Commission and is currently in place at Liberty Utilities (Midstates Natural Gas) Corp. The Company believes these revisions would help address concerns regarding the current proposal.

   Regarding Staff's SRLE proposal, the Company appreciates Staff's willingness to address the Company's need for a revenue stabilizing mechanism; however, the Company has several concerns regarding the proposed SRLE mechanism, including: (a) its potential impact on Time-of-Use ("TOU") rates as the Company plans to design, propose and implement TOU rates (as well as other alternative rate designs) following implementation of AMI/ smart meters; (b) the loss of new customer and sales revenues that would be credited to customers under the mechanism; and (c) the potential asymmetrical nature of the mechanism; i.e., the potential over time for revenue increases under the SRLE reconciliation process to be less than revenue decreases.

Thus, while the Company appreciates Staff's concerns regarding the proposed WNR, the Company continues to believe the WNR is the preferred approach and is willing to address those concerns with the considerations discussed above including implementation as a "Pilot Program".

2. There are concerns at this time with Staff's recommendation to consolidate the customer charge, head block and summer tail block rates for Schedules CB and SH, while maintaining distinct winter tail block rates. While Staff's recommendation has several benefits, the Company's concern is customer bill impacts and whether some customers may experience significant bill increases as a result of the change. The Company plans to evaluate the customer bill impact of Staff's recommendation over the next several weeks and provide an update on its assessment in surrebuttal testimony.

3. There are concerns at this time with Staff's recommendation to consolidate Schedules GP and TEB. While Staff's recommendation has several benefits, the Company's concern is customer bill impacts and whether some customers may experience significant bill increases as a result of the change. The Company plans to evaluate the customer bill impact of Staff's recommendation over the next several weeks and provide an update on its assessment in surrebuttal testimony.

4. There are concerns with Staff's recommendation to merge Schedule PFM into consolidated Schedules GP and TEB in a future rate case proceeding. As an alternative, the Company would consider merging Schedule PFM into Schedule CB.

5. While the Company was able to agree with some components of Staff's recommendations concerning their proposed revenue requirements, the Company does not support an overall reduction in the Company's revenue requirements. Please refer to the Rebuttal Testimony of Company Witness Ms. Sheri Richard on the Company's specific concerns with Staff's proposed Revenue Requirement.[15] However, the Company does support Staff's recommendation that Schedules CB and SH, Schedule LP and Schedules GP and TEB receive a lower class increase than Schedule RG in the context of an overall rate increase as well as a higher class decrease in the context of an overall rate decrease.

6. There are concerns with Staff's recommendation to maintain the current customer charges for Schedule RG and consolidated Schedules CB and SH of $13.00 per month and $22.69 per month, respectively, and reduce current customer charges for consolidated Schedules GP and TEB of $69.49 per month. Instead, the Company recommends an increase in customer charges to the levels proposed in the Company's filing. Further, the Company recommends that class revenues not recovered through the customer charge should be recovered through the energy rates in a uniform manner.

[15] Sheri Richard Rebuttal Testimony filed on March 3, 2020

7. There are concerns with Staff's recommendation to maintain Schedule PFM rates at its pre-tax reduction level. Instead, the Company proposes to adjust Schedule PFM revenue levels consistent with the approach taken for Schedules GP and TEB.
8. The Company takes no position on Staff's recommendation to change Special Transmission Service Contract's ("SC-P") on-peak, off-peak, and shoulder energy rates to better reflect the market energy prices during these periods.
9. There are concerns with Staff's recommendation to change the production allocator. The Company recommends continued use of the Average and Excess ("A&E")/ 12NCP method.
10. There are concerns with Staff's recommendations to classify FERC distribution plant accounts 364, 366, and 368 based on a zero-intercept method. While the Company supports the use of a zero-intercept method, there are concerns with certain data used in Staff's calculations of the zero-intercept.
11. There are concerns with Staff's proposal to allocate primary distribution plant facilities based on sum of each class's coincident peak ("CP") demands at primary voltage levels. Instead, the Company recommends allocation of primary and secondary distribution plan on 6NCP.
12. The Company supports Staff's proposal to allocate service lines and meter costs using the number of meters instead of the number of customers.
13. There are concerns with Staff's allocation of General Plant and A&G expenses that appears to be based on, for the most part, an energy sales allocator. Instead, the Company recommends allocation based on a combination of total plant composite allocator and labor-related O&M expense allocator.

14. The Company supports MECG's recommendation to incorporate a revenue neutral adjustment for Schedule RG to align with the class cost of service, subject to customer bill impact considerations.
15. The Company supports MECG's recommendation to revise allocation of interruptible credits for SC-P class.
16. The Company supports MECG's recommendation to firm-up current interruptible revenues to properly match with cost allocation of all fixed production plant.
17. The Company supports MECG's recommendation to apply any rate increases for Schedule LP to the billing demand and facility charges and to apply any rate decreases to the energy charges.
18. There are concerns with MECG's recommendation to utilize A&E/ 6NCP production allocator. Instead, the Company proposes to utilize the A&E/ 12NCP allocator.
19. There are concerns with MECG's recommendation to utilize 1NCP distribution allocator. Instead, the Company proposes to utilize the 6NCP allocator.
20. The Company supports MECG's recommendation to allocate the cost of the economic development rider discount on revenues pursuant to SB 564.

IV. THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATIONS

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S SRLE PROPOSAL?

A. As stated earlier, the Company appreciates Staff's concerns regarding the Company's proposed WNR and would be willing to consider revisions to the proposal, such as: (a) calculation of the weather adjustment on a calendar year basis rather than on a monthly and

(b) implementation of the WNR as a "Pilot Program" subject to evaluation by the Commission, Staff and other key stakeholders. The revisions would create a mechanism more aligned with the Weather Normalization Adjustment Rider ("WNAR"), which has been approved by the Commission and is currently in place at Liberty Utilities (Midstates Natural Gas) Corp. The Company believes these revisions would help address concerns regarding the current proposal.

Regarding Staff's SRLE proposal, the Company appreciates Staff's willingness to address the Company's need for a revenue stabilizing mechanism; however, the Company has several concerns regarding the proposed SRLE mechanism, including: (a) its potential impact on Time-of-Use ("TOU") rates as the Company plans to design, propose and implement TOU rates (as well as other alternative rate designs) following implementation of AMI/ smart meters; (b) the loss of new customers and sales revenues that would be credited to customers under the mechanism; and (c) the potential asymmetrical nature of the mechanism; i.e., the potential over time for revenue increases under the reconciliation process to be less than revenue decreases.

Regarding the Company's TOU rate concerns, TOU rates are generally designed and implemented based on hours of the day. The TOU rate structure is different than the current block rate structure. Thus, implementation of the TOU rate structure may require a substantial redesign of the proposed SRLE mechanism.

Regarding the Company's concern regarding the loss of new customer and sales revenues, when applicable the Company currently retains between rate cases the incremental revenues associated with customer and sales growth. When applicable the incremental revenues are used to offset plant investments and expenses related to serving the customer and sales growth. Under the proposed SRLE mechanism, the Company would refund to all customers the incremental revenues associated with customer and sales growth above the proposed 400 kWh threshold. For example, under the SRLE mechanism, the Company would refund approximately 54.8 percent of incremental revenues associated with adding an average residential customer, as shown in Figure 1.

Figure 1: Impact of SRLE on Residential Customer and Sales Growth

New Customer	Incremental Bills and Sales			Rate		Incremental Revenues			
12,772 kWh/Yr	Summer	Winter	Total	Summer	Winter	Summer	Winter	Total	%
# of Bills	4	8	12	$ 13.00	$ 13.00	$ 52	$ 104	$ 156	9.0%
First 400 kWh	1,600	3,200	4,800	$ 0.13006	$ 0.13006	$ 208	$ 416	$ 624	36.1%
Next 200 kWh	800	1,600	2,400	$ 0.13006	$ 0.13006	$ 104	$ 208	$ 312	18.1%
Over 600 kWh	1,879	3,693	5,572	$ 0.13006	$ 0.10574	$ 244	$ 390	$ 635	36.8%
Total kWh	4,279	8,493	12,772			$ 609	$ 1,119	$ 1,727	100.0%
Revenues Subject to SRLE Reconciliation						$ 348	$ 599	$ 947	54.8%

Specifically, Figure 1 shows the incremental revenues associated with adding a new residential customer using 12,772 kWh per year is $1,727. Under the proposed SRLE mechanism, the portion of the incremental revenues that would be refunded to all customers (i.e., no longer retained by the Company) would be $947.00, or approximately 54.8 percent of the incremental revenues. The refunded portion represents revenues billed above the proposed 400 kWh threshold. Thus, implementation of the proposed SRLE would limit the Company's ability to offset the incremental costs associated with adding new customers and sales.

Finally, the Company is concerned that over time the potential for revenue increases under the reconciliation process may be less than revenue decreases since there may be a higher likelihood that decreases in sales and revenues would impact the first 400 kWh block (that is not subject to reconciliation) than would increases in sales and revenues. Specifically, the concern is that warm winter weather, for example, would likely decrease sales in the first 400 kWh block more than cold winter weather would increase sales in the first 400 kWh block. For example, if we assume during a warmer-than-normal winter a customer's actual monthly use is 100 kWh less than normal monthly use and during a colder-than-normal winter a customer's actual monthly use is 100 kWh more than normal monthly use. Over time, one would expect that the higher use during a colder-than-normal winter would offset the lower use during a warmer-than-normal winter. However, under the proposed SRLE, the Company's concerns is that the higher revenues associated with the higher use during a colder winter may not offset the lower revenues associated with lower use during a warmer winter because the higher use may occur above the 400 kWh block (and thus subject to reconciliation) while the lower use may occur in the 400 kWh block (and thus not subject to reconciliation). Thus, the Company would incur revenue losses in the 400 kWh block under warmer-than-normal weather that would not be offset by revenue gains in the 400 kWh block during colder-than-normal weather. As a result, revenue stabilization may be potentially limited under the proposed SRLE.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION TO CONSOLIDATE SCHEDULES CB AND SH'S CUSTOMER CHARGE, HEAD BLOCK AND SUMMER TAIL BLOCK RATES BUT MAINTAIN DISTINCT WINTER TAIL BLOCK RATES?

A. The Company has concerns at this time with Staff's recommendation to consolidate Schedules CB and SH's customer charges, head block and summer tail block rates but maintain distinct winter tail block rates. The Company agrees there may be benefits associated with the proposed consolidation as: (1) presently, Schedules CB and SH have identical rate structures and customer charges; (2) the cost of service differences between Schedules CB and SH can be recognized by maintaining distinct winter tail block rates; (3) potential bill impact concerns related to the proposed rate changes can be addressed by maintaining distinct winter tail block rates; and (4) consolidation of rates and charges in general helps to simplify the Company's rate administration efforts and customer communications.

However, the Company's primary concern is customer bill impacts and whether some customers may experience significant bill increases as a result of the change. The Company plans to evaluate customer bill impacts over the next several weeks and provide an update on its assessment in surrebuttal testimony.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION TO CONSOLIDATE SCHEDULE GP AND TEB?

A. The Company has concerns at this time with Staff's proposal to consolidate Schedule GP and TEB's rates. The Company agrees there may be benefits associated with the proposed consolidation as: (1) Schedules GP and TEB have identical customer charges and rate structures, (2) Schedules GP and TEB have similar a cost of service, and (3) consolidating rates and charges in general helps to simplify the Company's rate administration efforts and customer communications.

However, the Company's primary concern is customer bill impacts and whether some customers may experience significant bill increases as a result of the change. The Company plans to evaluate customer bill impacts over the next several weeks and provide an update on its assessment in surrebuttal testimony.

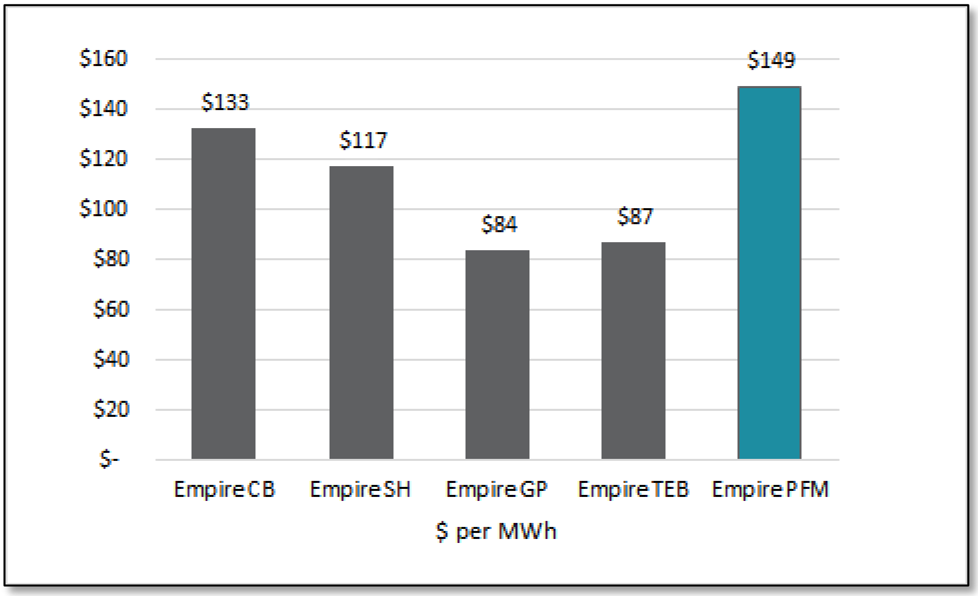
Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION TO MERGE SCHEDULE PFM INTO CONSOLIDATED SCHEDULES GP AND TEB?

A. The Company has concerns with Staff's proposal to merge Schedule PFM into the consolidated Schedules GP and TEB in a future rate proceeding. The Company's position is based on three considerations: (1) Schedule PFM's rate structure is different than the consolidated Schedules GP and TEB's rate structure; (2) Schedule PFM's cost of service is different than the consolidated Schedules GP and TEB's cost of service, and (3) since the Company has concerns with Schedules GP and TEB consolidation, it cannot support a further consolidation.

Specifically, Schedule PFM's rate structure consists of a head block for the first 700 kWh and a tail block for the remainder. This rate structure is not consistent with Schedules GP and TEB's rate structure, which consists of two demand charges and a three-tiered energy rates.

As an alternative, the Company would consider subject to customer bill impact considerations merging Schedule PFM into Schedule CB because the rate structures and cost of service are more comparable to than Schedules GP and TEB, as shown in Figure 2 (below).

Figure 2: PFM Class vs. CB, SH, GP, and TEB Class Cost of Service (Company's Filed CCOS)



The Figure shows Schedule PFM's cost of service of $149.00 per MWH is more comparable to Schedule CB's cost of service of $133.00 per MWH than Schedule GP or Schedule TEB's cost of service of $84.00 and $87.00 per MWH, respectively.

However, the Company's primary concern is customer bill impacts and whether certain customers may experience significant bill increases as a result of the change. The Company plans to evaluate customer bill impacts over the next several weeks and provide an update on its assessment in surrebuttal testimony.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION ON SETTING CLASS REVENUE TARGETS?

A. While the Company was able to agree with some components of Staff's recommendations concerning their proposed revenue requirements, the Company does not support an overall reduction in the Company's revenue requirements. Please refer to the Rebuttal Testimony of Company Witness Ms. Sheri Richard on the Company's specific concerns with Staff's proposed Revenue Requirement.

However, there are aspects of Staff's recommendation to setting class revenue targets that the Company does support. Specifically, the Company supports the approach that Schedules CB and SH, Schedule LP and Schedules GP and TEB receive lower rate increases than Schedule RG in the context of an overall rate increase and a higher rate decrease in the context of an overall rate decrease. The approach is consistent with the Company's testimony and is supported by the results of the CCOS.[16]

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION ON RATE DESIGN CHANGES?

A. The Company has concerns with Staff's recommendation to maintain the current customer charges for Schedules RG, CB, and SH, and reduce current customer charges for GP and TEB. In addition, the Company supports a more uniform change in energy rates.

Specifically, the Company has concerns with maintaining Schedule RG's current customer charge of $13.00 per month. The Company supports an increase in the customer charge to $19.00 per month to better align with the underlying customer-related costs of $28.95 per month. The primary difference between the Company and Staff's calculation of customer-related costs is related to customer-related facilities. The Company's calculation includes such costs as customer-related while Staff's calculation does not, and

[16] Testimony of Timothy S. Lyons, pgs. 10-13.

the Company's approach is consistent with the classification in the NARUC manual.[17] However, the Company agrees with Staff that class revenues not recovered through the customer charge should be recovered through a uniform change in the energy rates.

The Company has concerns with maintaining Schedules CB and SH's current customer charge of $22.69 per month. The Company supports an increase in the customer charge to $25.00 per month to better align with the underlying customer-related costs of $32.61 per month and $32.44 per month for Schedules CB and SH, respectively. As stated above, there are differences between the Company and Staff's calculation of customer-related costs. The Company agrees with Staff that class revenues not recovered through the customer charge should be recovered through the energy rates.

Finally, the Company has concerns with a reduction in Schedules GP and TEB's current customer charge of $69.49 per month. Instead, the Company supports maintaining the customer charge at current levels.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION TO MAINTAIN SCHEDULE PFM RATES AT ITS PRE-TAX REDUCTION LEVEL?

A. The Company has concerns with Staff's recommendation to maintain Schedule PFM rates at their pre-tax reduction level. The Company's CCOS shows that Schedule PFM rates currently recover more than their underlying cost of service. The Company proposes to adjust Schedule PFM revenue levels consistent with Schedules GP and TEB.

[17] NARUC Electric Utility Cost Allocation Manual, on pg. 90 states: "Distribution Plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility system."

Staff's proposal appears to be based on the results of its CCOS. The primary difference between the results of the Company and Staff's CCOS appears to be the allocation of 908.4 expenses to Schedule PFM customers, as shown in Figure 3 (below).

Figure 3: Account 908.4 Allocation Staff vs. Company Filed

908.4 Commercial Customer Assistance	Staff Allocation	Empire Allocation	Difference %
RG	0.0%	0.0%	0.0%
CB/SH	25.0%	87.1%	-62.1%
GP/TEB	25.0%	11.3%	13.7%
LP	0.0%	0.0%	0.0%
Feed & Grain	25.0%	0.0%	25.0%
SC-P	0.0%	0.0%	0.0%
Lighting	25.0%	1.6%	23.4%
Total	100.0%	100.0%	0.0%
PFM Class Allocation	25.00%		
Basis:	Assignment	Number of Customers	

The Figure shows that the Company's allocation of 908.4 commercial customer expenses allocates virtually no 908.4 expenses to Schedule PFM. In comparison, Staff's approach allocates 25.0 percent of the 908.4 expenses to Schedule PFM.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION TO THE CHANGES IN SCHEDULE SC-P PEAK, ON-PEAK AND SHOULDER ENERGY RATES?

A. The Company takes no position on Staff's proposed changes in Special Transmission Service Contract ("SC-P") on-peak, off-peak, and shoulder energy rates to "better reflect market energy prices" during these periods.

Q. PLEASE DESCRIBE STAFF'S RECOMMENDATION FOR ALLOCATING PRODUCTION PLANT.

A. Staff's recommendation for allocating production plant is based on the 100 Highest Hours method as described in a recent Regulatory Assistance Project ("RAP") publication "Electric Cost Allocation for a New Era," by Jim Lazar, Paul Chernick and William Marcus, edited by Mark LeBel (herein referred to as the "RAP Handbook"). The RAP Handbook discusses new approaches to cost allocation practices for electric utilities.[18] Staff mentions that implementation of methods included in the RAP Handbook was hindered by unavailability of data.

Going forward, Staff recommends detailed data collection and retention practices, particularly related to AMI/ smart meters. Staff states that its proposed 100 Highest Hours allocator mitigates Staff's concerns with the reliability of the hourly load data "as less emphasis is placed on the reliability of a relatively small number of hours than would occur using more simplistic traditional capacity allocation methods."

Q. WHAT IS YOUR UNDERSTANDING OF THE CONCEPTS PRESENTED IN THE RAP HANDBOOK?

A. As an initial matter, we agree that the RAP Handbook provides valuable guidance for electric cost allocation methodologies as the electricity system evolves.

Regarding the classification and allocation of production-related costs, the RAP handbook discusses several methodologies, including: [19]

[18] Staff report, pg. 25-26.
[19] "Electric Cost Allocation for a New Era," by Jim Lazar, Paul Chernick and William Marcus, edited by Mark LeBel, pg. 19

- Classify and allocate generation capacity costs using a time-differentiated method, such as the probability-of dispatch or base-intermediate-peak (BIP) methods, or classify capacity costs between energy and demand using the Equivalent Peaker method.
- Allocate demand-related costs for generation using a broad peak measure, such as the highest 100 hours or the loss-of-energy expectation.

The RAP Handbook also mentions that for hourly allocation methods for generation, "Most generation costs should be assigned to the hours in which the relevant facilities are actually used and to all hours across the year, not solely based on measurements in a subset of these hours."[20]

The RAP Handbook discusses allocation methods for generation costs that represents usage through the year, as well as usage at peak periods.[21] This is generally consistent with a traditional Average & Excess or Average & Peak method. However, the primary difference between the traditional methods and RAP's new methods appears to be the granularity of data employed in classifying and allocating costs which increases the accuracy of cost allocation.

Q. DOES THE COMPANY HAVE CONCERNS WITH STAFF'S APPROACH?

A. Yes. Staff's 100 Highest Hours method does not specifically address RAP's emphasis on employing an allocation method for generation costs that represents usage throughout the

[20] Id. pg. 20-21
[21] This is also apparent in the Sankey Diagram presented on pg. 23 of the RAP handbook. The diagram shows generation costs classified and allocated based on all hours of usage, intermediate hours of usage, and peak hours of usage.

year. Specifically, Staff's approach classifies all generation facilities as 100% demand-related, i.e., as 'Peaker' facilities, and allocates costs based on the 100 highest peak hours.

Staff cites section 9.3 of the RAP handbook in selecting this allocation method. However, the cited section discusses the 100 Highest Hours method in the context of allocation factors for demand-related costs developed by "legacy demand/energy classification methods". Section 9.3 appears to describe implementation of the 100 Highest Hours method assuming there is an energy-related portion of production costs allocated using a separate method as well. This is based in part on RAP's discussion in sections 9.1 and 9.2 where RAP discusses methodologies for classifying and allocating energy-related generation costs. RAP also states: "Many utilities and regulators acknowledge that a large portion of generation investment and non-dispatch O&M costs is incurred to serve energy requirements."[22] Based on this, an appropriate allocation method for production-related costs reflects both energy-related and demand-related usage.

Staff's methodology effectively classifies all costs as demand-related and allocates based on 100 Highest Peak Hours. This creates a shift in cost allocation from higher load factor customers to lower load factor customers.

Q. WHAT IS THE COMPANY'S RECOMMENDATION ON THE PRODUCTION PLANT ALLOCATOR?

A. The Company agrees with the need to evaluate new allocation methods for generation costs based on the discussions in RAP Handbook. However, as Staff mentions, the development

[22] "Electric Cost Allocation for a New Era," by Jim Lazar, Paul Chernick and William Marcus, edited by Mark LeBel, pg. 112

of such methods is challenged by unavailability of granular hourly load data such as from AMI/ smart meters. In future proceedings, when such data is available, the Company plans to evaluate and may consider new allocation methods for production costs consistent with the approaches discussed by RAP.

In the meantime, the Company recommends the allocation of production plant based on the Average and Excess (A&E) method. The Company's choice of production plant allocator was based on an understanding of what drives production costs. The approach used in the Company's study to allocate production plant was the A&E method since it is consistent with how costs are incurred, allocating a portion of production plant based on energy consumption and the remaining portion based on peak demands. Specifically, the energy portion of plant costs is allocated to each rate class based on average kWh sales throughout the year, while peak demands are based on peak kW demands throughout the year.

The A&E allocator consists of two components. The first component of the A&E allocator is the average demand, which represents the energy portion of the production plant. It represents each rate class's share of the average demand. This component is calculated as each class's share of total kWh sales. The average demand component is weighted by the system load factor representing that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100.0 percent load factor.

The second component of the A&E allocator is the excess demand, which represents the peak demand portion of the production plant. It represents each rate class's share of the excess demand. This component is calculated as each class's share of the excess demand – or the difference between the class peak demand and the class average demand. The class peak demand is based on NCP demands, consistent with the methodology described in the NARUC Manual.[23] The approach to calculate the A&E allocator in the Company's class cost of service study followed the methodology described in the NARUC Manual.[24]

Figure 4 (below) compares the Company and Staff's production cost allocators.

Figure 4: Production Cost Allocator Staff vs. Company Filed

Production Allocation Rate Class	Staff 100 Highest Hours	Empire-Filed A&E 12 NCP	Difference %
RG	48.8%	47.5%	1.3%
CB/SH	10.4%	10.0%	0.4%
GP/TEB	26.2%	25.8%	0.4%
LP	13.4%	14.7%	-1.3%
Feed & Grain	0.0%	0.0%	0.0%
SC-P	1.1%	0.9%	0.2%
Lighting	0.1%	1.1%	-1.0%
Total	100.0%	100.0%	0.0%

Figure 4 shows that the 100 Highest Hours method generally allocates more cost to low load factor classes. For example, the 100 Highest Hours method allocates 48.8 percent of production plant costs to Schedule RG, while the A&E/ 12NCP method allocates 47.5 percent of production plant costs allocated to Schedule RG.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION TO CLASSIFY DISTRIBUTION PLANT ACCOUNTS 364, 366 AND 368 USING THE ZERO INTERCEPT METHOD?

[23] NARUC Electric Utility Cost Allocation Manual at pg. 49-52.
[24] *Id.* at pg. 50

A. The Company has concerns regarding Staff's classification of distribution plant accounts 364, 366 and 368 using the zero-intercept method. While the Company does not have concerns regarding the zero-intercept method (as it is one of the approaches recognized by NARUC for classification of these accounts)[25], the Company does have concerns regarding certain data used in the study since it results in significant differences between the Company and Staff's classification results.

Specifically, the Company is concerned there are large discrepancies in the component costs used in the minimum system studies conducted by the Company and the zero-intercept studies conducted by Staff. A comparison of results is shown in Figure 5 (below).

Figure 5: Distribution Plant Accounts 364-368 Customer-Related Cost Classification Staff vs Company Filed

Distribution Plant	Staff		Empire-Filed	
Classification	Customer	Demand	Customer	Demand
Acct. 364 Poles	22.6%	77.4%	53.1%	46.9%
Acct. 365 OH Line	12.8%	87.2%	12.8%	87.2%
Acct. 366 Underground	42.3%	57.7%	100.0%	0.0%
Acct. 367 Underground Cond.	40.8%	59.2%	44.6%	55.4%
Acct. 368 Transformers	9.8%	90.2%	43.0%	57.0%

The Figure shows large differences in classification of costs for Accounts 364, 366, and 368. For example, the Figure shows that Staff's approach classifies 22.6 percent of Account 364 costs as customer-related, while the Company's methodology classifies 53.1 percent of Account 364 costs as customer-related.

The Company has the following concerns on Staff's calculations based on the review of Staff workpapers:

[25] NARUC Electric Utility Cost Allocation Manual at pg. 92-94.

1. For Account 364 (Poles), Staff's methodology does not consider the cost of anchors and guys that are recorded in Account 364. The Company's minimum system study accounts for anchors and guys which contributes to higher customer-related costs. Thus, the Company recommends utilizing the Company's minimum system study.
2. For Account 366 (Underground Conduits), Staff's methodology does not consider the cost of vaults and pedestals that are recorded in Account 366. The Company's minimum system study accounts for such costs which shows that the minimum system costs are equal to or higher than total system costs. As a result, the Company's study classifies Account 366 as 100.0 percent customer related. The Company recommends utilizing the Company's minimum system study.
3. For Account 368 (Transformers), Staff conducted a zero-intercept study using limited data (i.e., two data points): a 15kVA overhead transformer cost, and a 25kVA underground transformer cost. These costs are not apples-to-apples as installation of a 25kVA underground transformer may include higher costs than installation of a 25kVA overhead transformer. This would help to explain Staff's study results which show a negative zero-intercept. As a result, the Company recommends classification of Account 368 costs utilizing the Company's minimum system study.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S RECOMMENDATION TO ALLOCATE PRIMARY AND SECONDARY DISTRIBUTION FACILITIES USING THE SUM OF COINCIDENTAL PEAK DEMANDS?

A. The Company has concerns with Staff's proposal to allocate primary distribution plant facilities based on sum of each class's coincident peak demands at primary voltage levels. In addition, a review of Staff workpapers shows that Staff's allocation for secondary distribution facilities is based on maximum coincident peak demand for customer classes through the test year period.[26]

The Company's choice of distribution allocator was based on an understanding of what drives distribution costs.

The distribution system was designed and built to serve local peak demands in both the summer and winter months. The Company proposed the 6NCP allocator since it reflects how the Company plans for distribution capacity; *i.e.*, to support local peak demand in both the summer and winter months.

The distribution system was designed and built to serve local peak demands (thus the need to use NCP rather than CP); and the local peak demands occur in the winter and summer. As a result, the Company recommends using the 6 months' non-coincident peak allocators for distribution related costs.

The impact of the allocation methodologies on primary distribution costs is shown in Figure 6 (below).

[26] Staff Class Cost of Service Study Workpapers

Figure 6: Primary Distribution Cost Allocator Staff vs. Company Filed

Primary Distribution Rate Class	Staff 12 CP	Empire-Filed 6 NCP	Difference %
RG	50.6%	49.9%	0.7%
CB/SH	9.9%	10.2%	-0.3%
GP/TEB	26.1%	25.1%	0.9%
LP	13.3%	13.7%	-0.3%
Feed & Grain	0.0%	0.0%	0.0%
SC-P	0.0%	0.0%	0.0%
Lighting	0.2%	1.1%	-0.9%
Total	100.0%	100.0%	0.0%

The Figure shows that Staff's 12CP method results in a higher allocation of primary distribution costs to Schedules RG, GP and TEB, and a lower allocation of primary distribution costs to the remaining schedules. For example, the Figure shows that Staff's method allocates 50.6 percent of primary distribution costs to Schedule RG, while the Company's method allocates 49.9 percent of primary distribution costs to Schedule RG.

The impact of Staff's and Company's allocation methodologies on secondary distribution costs is shown in Figure 7 (below).

Figure 7: Secondary Distribution Cost Allocator Staff vs. Company Filed

Secondary Distribution Rate Class	Staff Highest CP	Empire-Filed 6 NCP	Difference %
RG	61.4%	58.1%	3.2%
CB/SH	11.7%	11.9%	-0.2%
GP/TEB	24.5%	27.0%	-2.4%
LP	1.5%	1.7%	-0.2%
Feed & Grain	0.0%	0.0%	0.0%
SC-P	0.0%	0.0%	0.0%
Lighting	0.8%	1.3%	-0.5%
Total	100.0%	100.0%	0.0%

The Figure shows that Staff's method allocates 61.4 percent of secondary distribution costs to Schedule RG, while the Company's method allocates 58.1 percent of secondary distribution costs to Schedule RG.

Q. WHAT IS THE COMPANY'S RESPONSE TO STAFF'S ALLOCATION OF GENERAL PLANT AND A&G EXPENSES USING AN ENERGY SALES ALLOCATOR?

A. The Company has concerns with Staff's allocation of General Plant and A&G expenses which appear to be allocated, for the most part, based on an energy sales allocator. Specifically, customer energy usage does not drive the costs of General Plant and A&G expenses.

The Company's choice of General Plant allocator was based on an understanding of what drives these costs. General Plant facilities are generally used by the Company employees. Accordingly, the General Plant costs were allocated based on a composite of labor-related O&M expenses. The Company's approach is generally consistent with the allocation method for these costs described in the NARUC manual.[27]

The Company's choice of A&G expenses allocator was also based on an understanding of what drives these costs. Labor related A&G expenses (such as Accounts 920 through 926) are allocated based on a composite of labor-related O&M expenses, while Plant related A&G expenses are allocated based on a composite Total Plant allocation. The

[27] NARUC Electric Utility Cost Allocation Manual, pg. 105

Company's approach is generally consistent with the allocation method for these costs described in the NARUC manual.[28]

A comparison between Company's and Staff's allocation of General Plant is shown in Figure 8 (below).

Figure 8: General Plant Allocation Staff vs. Company Filed

General Plant Rate Class	Staff Allocation	Empire-Filed Allocation	Difference %
RG	39.6%	70.6%	-31.0%
CB/SH	9.4%	12.3%	-2.8%
GP/TEB	29.2%	9.9%	19.2%
LP	19.3%	5.9%	13.4%
Feed & Grain	0.0%	0.0%	0.0%
SC-P	1.6%	0.3%	1.4%
Lighting	0.8%	1.0%	-0.2%
Total	100.0%	100.0%	0.0%

The Figure shows that Staff's approach results in a higher allocation of general plant costs to Schedules GP/TEB, LP, and SC-P, and a lower allocation of general plant costs to the remaining schedules. For example, the Figure shows that Staff's method allocates 39.6 percent, of general plant costs to Schedule RG while the Company's method allocates 70.6 percent of general plant costs to Schedule RG.

A comparison between Company's and Staff's allocation of A&G expenses is shown in Figure 9 (below).

[28] NARUC Electric Utility Cost Allocation Manual, pg. 106-107

Figure 9: A&G Expenses Allocation Staff vs. Company Filed

A&G Expenses Rate Class	Staff Allocation	Empire-Filed Allocation	Difference %
RG	39.9%	68.8%	-28.9%
CB/SH	9.5%	12.1%	-2.6%
GP/TEB	29.0%	11.2%	17.9%
LP	19.2%	6.6%	12.6%
Feed & Grain	0.0%	0.0%	0.0%
SC-P	1.6%	0.3%	1.3%
Lighting	0.8%	1.1%	-0.3%
Total	100.0%	100.0%	0.0%

The Figure shows that Staff's method allocates more A&G expenses to Schedules GP/TEB, LP, and SC-P, and less A&G expenses to the remaining schedules. For example, the Figure shows that Staff's method allocates 39.9 percent of A&G expenses to Schedule RG while the Company's method allocates 68.8 percent of A&G expenses to Schedule RG.

Q. DOES THE COMPANY HAVE ANY CONCERNS RELATED TO STAFF'S PROPOSED BILLING DETERMINANTS?

A. Yes. It appears Staff's billing determinants significantly understate the Summer billed demands for Schedule LP customers as shown in Staff's workpaper. Figure 10 (below) shows the differences between billing determinants for Schedule LP customers for Staff and the Company.

Figure 10: LP Billing Determinants Staff Workpaper vs. Company Filed

Large Power (LP) Billing Determinants	Staff Workpaper	Company Filed	Difference	Difference %
Number of Customers	40	40	0	0.2%
First Step- Winter (MWh)	339,809	345,004	(5,194)	-1.5%
Second Step- Winter (MWh)	168,334	169,992	(1,659)	-1.0%
First Step- Summer (MWh)	191,871	190,469	1,402	0.7%
Second Step- Summer (MWh)	96,899	100,436	(3,537)	-3.5%
Facility Demand (kW)	1,655,310	1,660,265	(4,955)	-0.3%
Billed Demand Winter (kW)	1,001,913	1,003,759	(1,846)	-0.2%
Billed Demand Summer (kW)	56,784	553,295	(496,512)	-89.7%

The Figure shows slight differences in Staff proposed billing determinants with Company filed billing determinants. However, the difference in Summer billed demand is substantial (i.e., 89.7 percent).

V. THE COMPANY'S RESPONSE TO MECG'S RECOMMENDATIONS

Q. WHAT IS THE COMPANY'S RESPONSE TO MECG's RECOMMENDATION TO INCORPORATE A REVENUE NEUTRAL ADJUSTMENT TO REFLECT THE RESULTS OF THE CCOS?

A. The Company supports MECG's recommendation to incorporate a revenue neutral adjustment to reflect the misalignment between class revenues and the results of the CCOS. As mentioned in direct testimony, the Company believes the results of the class cost of service study support a higher rate increase for residential customers since their current rates recover less than the cost of service, consistent with the Company's rate design proposals in its filing. However, the Company believes that any revenue neutral adjustment should consider customer bill impacts.

Q. WHAT IS THE COMPANY'S RESPONSE TO MECG'S RECOMMENDATION TO ALLOCATE THE COST OF SCHEDULE SC-P'S INTERRUPTIBLE CREDITS TO ALL OF THE OTHER RATE CLASSES?

A. The Company supports MECG's recommendation to allocate the cost of Schedule SC-P's interruptible credits to all customer classes on the basis of the Average & Excess allocator to align with the benefits to generation facilities. The Company also agrees with MECG that the A&E allocator used to allocate interruptible credits should not include interruptible load. Figure 11 (below) shows the re-allocation of interruptible credit to all rate classes based on the adjusted A&E allocator.

Figure 11: Interruptible Credit Allocation

Rate Class	Target Revenues	Int. Credit Adjustment	Int. Credit Recovery	Target Revenues Adjusted	Increase / (Decrease) %
RG	$ 228,477,610	$ -	$ 180,882	$ 228,658,493	0.08%
CB	45,753,149	-	30,365	45,783,513	0.07%
SH	10,484,858	-	7,828	10,492,685	0.07%
GP	87,668,060	(12,144)	68,878	87,724,794	0.06%
SC-P	4,681,909	(365,712)	319	4,316,516	-7.80%
TEB	37,534,359	-	29,120	37,563,478	0.08%
PFM	74,497	-	68	74,565	0.09%
LP	65,200,548	-	56,335	65,256,884	0.09%
MS	15,414	-	7	15,421	0.05%
SPL	2,327,065	-	2,103	2,329,169	0.09%
PL	4,231,799	-	1,594	4,233,393	0.04%
LS	139,838	-	358	140,196	0.26%
Total	$ 486,589,107	$ (377,856)	$ 377,856	$ 486,589,107	0.00%

Q. WHAT IS THE COMPANY'S RESPONSE TO MECG'S RECOMMENDATION TO FIRM-UP INTERRUPTIBLE CUSTOMERS CURRENT REVENUES TO PROPERLY MATCH THE COST ALLOCATION OF ALL FIXED PRODUCTION COSTS?

A. The Company supports the need to firm up interruptible customers' current revenues to properly match with cost allocation of all fixed production plant. Figure 12 (below) shows the impact on SC-P class rate of return with current revenues and current revenues firmed up for the interruptible credit.

Figure 12: SC-P Class Interruptible Credit Firm-Up Impact

SC-P Rate Class CCOS Allocation		Company Filed		Interruptible Credit Firm-Up		Company Rebuttal
Rate Base	$	8,824,969	$	-	$	8,824,969
Current Revenues	$	5,183,196	$	365,393	$	5,548,589
O&M Expenses	$	(3,671,187)	$	-	$	(3,671,187)
Depreciation & Amort.	$	(402,651)	$	-	$	(402,651)
Taxes Other than Inc.	$	(143,751)	$	-	$	(143,751)
Income Taxes	$	(115,755)	$	(87,778)	$	(203,533)
Total Expenses	$	(4,333,344)	$	(87,778)	$	(4,421,123)
Net Operating Income	$	849,852	$	277,615	$	1,127,467
Rate of Return		9.63%				12.78%

The Figure shows that the SC-P class rate of return increases from 9.63 percent to 12.78 percent resulting from the revenue firm-up.

Q. WHAT IS THE COMPANY'S RESPONSE TO MECG'S RECOMMENDATION TO APPLY ANY SCHEDULE LP RATE INCREASE TO THE BILLING DEMAND AND FACILITY CHARGES AND APPLY ANY SCHEDULE LP DECREASES TO THE ENERGY CHARGES?

A. The Company supports MECG's recommendation to apply approved increase for the LP class to the billing demand and facility charges and apply any approved decreases to the energy charge. This approach better aligns recovery of demand-related costs through demand charges and energy-related costs through energy-related charges, as shown in Figure 13 (below).

Figure 13: LP Current Revenues vs CCOS Breakdown by Cost Classification

LP Class Revenues By Cost Classification	Total LP Class	Demand Related	Customer Related	Energy Related
Class Cost of Service				
Revenue Requirement $	$ 74,849,688	$ 39,473,259	$ 1,361,331	$ 34,015,098
Breakdown %	**100%**	**53%**	**2%**	**45%**
Current Rate Revenues				
Demand Charges	$ 20,495,057	$ 20,495,057		
Customer Charge	135,820		135,820	
Energy Charges	43,572,079			43,572,079
Current Rate Revenues	$ 64,202,957	$ 20,495,057	$ 135,820	$ 43,572,079
Breakdown %	**100%**	**32%**	**0%**	**68%**

The Figure compares Schedule LP's current revenues to the CCOS results. Specifically, the Figure shows that 53.0 percent of Schedule LP's cost of service is related to demand-related costs while only 32.0 percent of revenues are recovered through demand-related charges.

Q. WHAT IS THE COMPANY'S RESPONSE TO MECG'S RECOMMENDATION TO ALLOCATE PRODUCTION COSTS UTILIZING A&E FOR 3 MONTHS IN THE SUMMER AND 3 MONTHS IN THE WINTER?

A. The Company has concerns with MECG's recommendation to allocate production costs utilizing A&E method for 3 months in the summer and 3 months in the winter because it is not consistent with how costs are incurred.

As stated earlier, the Company's choice of production allocator was based on an understanding of what drives production costs.

The use of the 12NCP results in a production allocator that is more aligned with how costs are incurred than the 6NCP.

Figure 14 (below) shows the comparison between MECG and Company proposed allocations for production costs.

Figure 14: A&E Allocator MECG vs. Company Filed

Production Allocation Rate Class	MECG A&E 6 NCP	Empire-Filed A&E 12 NCP	Difference %
RG	49.9%	47.5%	2.4%
CB	7.9%	8.0%	-0.1%
SH	2.1%	2.1%	0.1%
GP	17.1%	18.1%	-1.0%
SC-P	0.8%	0.9%	-0.1%
TEB	7.6%	7.6%	-0.1%
PFM	0.0%	0.0%	0.0%
LP	13.6%	14.7%	-1.1%
MS	0.0%	0.0%	0.0%
SPL	0.5%	0.6%	0.0%
PL	0.4%	0.4%	0.0%
LS	0.1%	0.1%	0.0%
Total	100.0%	100.0%	0.0%

The Figure shows that MECG's recommendation results in a higher increase in the low load factor rate classes. For example, the Figure shows that MECG's method allocates 49.9 percent of production costs to Schedule RG while the Company's method allocates 47.5 percent of production costs to Schedule RG.

Q. WHAT IS THE COMPANY'S RESPONSE TO MECG'S RECOMMENDATION TO ALLOCATE PRIMARY AND SECONDARY DISTRIBUTION PLANT FACILITIES ON A SINGLE NON-COINCIDENTIAL PEAK ALLOCATOR?

A. The Company has concerns with MECG's recommendation to allocate primary and secondary distribution plant facilities utilizing the single non-coincident peak allocator because it is not consistent with how costs are incurred.

As stated earlier, the Company's choice of distribution allocator was based on an understanding of what drives distribution costs. The distribution system was designed and built to serve local peak demands in both the summer and winter months. The Company proposed the 6NCP allocator since it reflects how the Company plans for distribution capacity; *i.e.*, to support local peak demand in both the summer and winter months. Figure 15 (below) compares the Company's proposed 6NCP allocation with single non-coincident peak allocation of primary distribution costs.

Figure 15: Primary Distribution Allocation 1NCP vs. Company Filed 6NCP

Primary Distribution Rate Class	1 NCP	Empire-Filed 6 NCP	Difference %
RG	50.2%	49.9%	0.3%
CB	8.4%	8.1%	0.4%
SH	2.1%	2.1%	0.0%
GP	17.7%	17.7%	0.0%
SC-P	0.0%	0.0%	0.0%
TEB	7.8%	7.5%	0.3%
PFM	0.0%	0.0%	0.0%
LP	12.6%	13.7%	-1.1%
MS	0.0%	0.0%	0.0%
SPL	0.5%	0.5%	-0.1%
PL	0.5%	0.4%	0.0%
LS	0.2%	0.1%	0.1%
Total	100.0%	100.0%	0.0%

The Figure shows that MECG's recommendation results in a slightly higher allocation of costs for Schedule RG. For example, the Figure shows a 50.2 percent allocation of primary distribution costs to RG class with the single non-coincident peak allocator, and a 49.9 percent allocation of costs utilizing Company's proposed 6 NCP allocator.

Q. WHAT IS THE COMPANY'S RESPONSE TO MECG'S RECOMMENDATION TO IMPLEMENT A REVENUE ALLOCATOR FOR THE SB 564 ECONOMIC DEVELOPMENT RIDER?

A. The Company supports the need to allocate the cost associated with the economic development rider discount on the basis of revenues, consistent with SB 564. Figure 16 (below) shows the re-allocation of economic development rider costs to all rate classes.

Figure 16: SB 564 Economic Development Rider (EDR) Discount Re-Allocation

Rate Class	Target Revenues	EDR Allocation Current	EDR Allocation Revised	Target Revenues Adjusted	Increase / (Decrease) %
RG	$ 228,658,493	$ (46,083)	$ 28,356	$ 228,640,765	-0.01%
CB	45,783,513	(7,262)	5,678	45,781,929	0.00%
SH	10,492,685	(1,217)	1,301	10,492,770	0.00%
GP	87,724,794	(721)	10,880	87,734,954	0.01%
SC-P	4,316,516	(112)	581	4,316,985	0.01%
TEB	37,563,478	(380)	4,658	37,567,756	0.01%
PFM	74,565	(4)	9	74,570	0.01%
LP	65,256,884	(4,455)	8,092	65,260,521	0.01%
MS	15,421	(1)	2	15,422	0.00%
SPL	2,329,169	(3)	289	2,329,455	0.01%
PL	4,233,393	(101)	525	4,233,817	0.01%
LS	140,196	(51)	17	140,163	-0.02%
Total	$ 486,589,107	$ (60,389)	$ 60,389	$ 486,589,107	0.00%

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

<u>**AFFIDAVIT OF TIMOTHY S. LYONS**</u>

STATE OF VERMONT)
) **ss**
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On the 5TH day of March, 2020, before me appeared Timothy S. Lyons, to me personally known, who, being by me first duly sworn, states that he a partner at ScottMadden, Inc and acknowledges that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

Timothy S. Lyons
Timothy S. Lyons

Subscribed and sworn to before me this 5TH day of March 2020.

Notary Public

My commission expires: 01/31/2021

Notary Public State of Vermont
Kevin Lemieux
Commission * No. 157.0008207 *
My Commission Expires January 31.2021

Kevin Lemieux
NOTARY PUBLIC
VERMONT