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MISSOURI PUBLIC SERVICE COMMISSION

Case No.: ER-2024-0261

Direct Testimony of Caroline Palmer

(Cost of Service Study/Rate Design)

On Behalf of

Consumers Council of Missouri

July 21, 2024

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics, Inc.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the electricity industry.

Q Please summarize your professional and educational experience.

A I am a Principal Associate at Synapse, where I provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings. The issues I cover in these cases include marginal and embedded cost-of-service studies, revenue allocation, advanced rate design, low-income rate design, load management, decoupling, distributed energy resource ("DER") interconnection and compensation, electric vehicle ("EV") infrastructure investments, and pilot frameworks. Prior to joining Synapse I worked at

Strategen Consulting for five years performing similar work. I have submitted expert testimony in eighteen dockets across ten jurisdictions.

I was awarded a Fulbright Research Fellowship to Greece in 2019 and supported clean energy policy consulting at Meister Consultants Group (now Cadmus) before that. I hold a Master of Public Policy from the Goldman School at UC Berkeley and a Bachelor of Science from Georgetown University. I have 10 years of professional experience. My resume is attached as Attachment CP-1.

Q Have you previously testified before the Missouri Public Service Commission?

A Yes, I testified in ER-2024-0319 and WR-2024-0320.

I have also sponsored testimony before a number of other commissions, including the New Hampshire Public Utilities Commission, Missouri Public Service Commission, New York Public Service Commission, the Massachusetts Department of Public Utilities, Maine Public Utilities Commission, the Oklahoma Corporation Commission, the North Carolina Utilities Commission, and the Nova Scotia Utility and Review Board. I have also assisted with testimonies and regulatory analyses in numerous other jurisdictions.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Consumers Council of Missouri (Consumers Council).

Q What is the purpose of your testimony?

A I address certain aspects of The Empire District Electric Company d/b/a Liberty's (Liberty or Company) class cost of service study (COSS), revenue allocation, and rate design proposals. The absence of discussion of other topics in this testimony should not be construed as support for, or opposition to, the Company's positions.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your conclusions.

A My conclusions are as follows:

- The Company's use of the minimum size and zero intercept methods for classifying substantial portions of its distribution system in its COSS does not reflect cost-causation principles and inflates cost allocations to residential customers.
- The Company's classification of AMI meter costs as 100 percent customer-related does not reflect cost causation.
- The Company's methodology for allocating revenue requirement among the customer classes is generally reasonable. However, it should reflect cost causation associated with a COSS that does not include a minimum size or zero intercept approach and that classifies AMI meters in a way that reflects the additional services they can provide.
- The Company's proposal to increase the residential fixed charge by 23% reduces customers' ability to control their own bills. It may also discourage conservation and render energy efficiency and load management investments less cost-effective.

Q What are your recommendations?

A I recommend that the Commission direct the Company to:

- Discontinue the minimum size and zero intercept methods and adopt the Basic Customer Method for distribution cost classification, which limits customer-related costs to those directly tied to the number of customers, such as metering and billing.

- Classify AMI meters as customer, demand, and energy related proportionally to the relative benefits that accrue to each of the three cost drivers based on quantification of AMI benefits. Based on the benefits quantified in other jurisdictions, I propose that Liberty initially classify AMI meters as 50% customer-related, 25% energy-related, and 25% demand-related.
- Allocate revenue requirement among customer classes based on a COSS that uses the Basic Customer Method rather than minimum size or zero intercept studies. Using the Company's proposed revenue requirement, this translates to a 30.3% revenue increase for the TC-RG Residential class.[1]
- Direct the Company to maintain its current residential monthly fixed charge at $13.00 and instead increase the volumetric rate in order to achieve the necessary revenue requirement increase.

III. ALLOCATED COST OF SERVICE STUDY

Overview of Cost of Service Studies

Q What is the purpose of a COSS?

A A COSS is used to assign the utility's revenue requirement to each customer or rate class in proportion to the costs imposed on the system by those customers. Thus, a cost of service study seeks to determine what costs are incurred to serve each class of customers.

[1] My use of the Company's revenue requirement to illustrate changes in class cost allocation does not imply endorsement of that revenue requirement.

Q How is a COSS performed?

A A COSS typically follows three steps. First, costs are functionalized by separating utility plant and expenses according to the primary functions they serve, such as generation, transmission, and distribution. Second, the functionalized rate base and operating costs are classified based on their primary cost drivers – typically as energy-related (commodity), demand-related (capacity), or customer-related. Finally, costs are either directly assigned to specific customers or allocated among customer classes using allocation factors based on energy use, peak demand, or customer counts.

Q How do analysts determine the appropriate approaches to cost classification and allocation?

A When selecting classification factors or allocators, the goal is to fairly allocate costs among different customer classes based on cost causation. Cost causation reflects the notion that the customer or set of customers that caused a cost should pay for the cost.[2] To determine cost causation, analysts often rely on economic theory and power system engineering considerations.

Q In your view, has the Company selected appropriate COSS methods?

A No. I have two primary concerns with the Company's COSS methods:

1. The Company classifies portions of the distribution system as partially "customer-related" based on flawed minimum system and zero-intercept methodologies; and
2. The Company's meter classification does not reflect AMI cost causation.

My testimony recommends alternative approaches that are better supported by economic theory and power system engineering.

[2] Liberty indicates that its classifications should "reflect cost causation." *See* Lyons Direct Testimony p.12.

Q How should COSS results be used in a rate case?

A Parties and the Commission should exercise judgement when using a utility COSS to inform revenue allocation or rate design, as it is an inherently imprecise tool in which cost analysts make numerous subjective determinations that may dramatically impact the study results. As such, utility cost of service studies should be one of several considerations used to guide decision-makers in revenue allocation and rate design, rather than being viewed as the sole determinant or final authority.

Liberty Should Not Classify Distribution System Costs Using a Minimum Size or Zero-Intercept Study

Q Did the Company classify certain distribution system costs as both customer-related and demand-related?

A Yes. The Company considers poles, underground and overhead conductors and conduits, and transformers (FERC accounts 364, 365, 366, 367, and 368) to have both demand- and customer-related components. The Company used minimum size and zero-intercept studies to determine the share of each of these accounts to classify as customer-related versus demand-related.

Q What is a minimum size study?

A A minimum size study is a cost analysis that estimates what the cost of the distribution system would be if the total system inventory was composed of the smallest equipment size. For each FERC account evaluated, the Company considers the cost of the minimum-sized equipment in the account to be customer-related. The Company considers the remaining cost of the actual distribution system to "reflect the cost of serving customer peak demands"[3] and therefore classifies it as demand-related.

Q What is a zero-intercept study?

A A zero-intercept study is a cost analysis that seeks to determine the cost of connecting customers to the system with a hypothetical zero size facility. The method involves regression analysis relating facility size and average costs, in which the intercept of the regression equation is considered the average cost of a hypothetical zero size facility.[4]

Liberty uses the minimum size method to classify accounts 365, 367, and 368 and the zero-intercept method to classify accounts 364 and 366.

Q Do the minimum size and zero-intercept studies deem significant portions of plant to be customer-related?

A Yes. These methods classify 35.5% to 46.1% of the analyzed distribution equipment as customer-related.[5]

Q What are your concerns with the minimum size and zero-intercept methods?

A I have three concerns with the minimum size and zero-intercept methods:

- They do not align with the Company's definition and treatment of customer costs;
- They inflate the costs classified as customer-related; and
- They are unsound to use as the basis for determining cost causation.

I discuss each concern sequentially.

[3] Lyons Direct Testimony p.19.
[4] Lyons Direct Testimony p.20.
[5] Direct Schedule TSL-3 p.366.

Q Why don't the minimum size and zero-intercept methods align with the Company's definition and treatment of customer costs?

A Per the Company, customer-related costs "vary with the number of customers."[6] This definition complements the 1992 National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual* ("NARUC Electric Manual"), which defines customer costs as "directly related to the number of customers served."[7] Indeed, after classifying customer-related costs, the Company allocates those costs based on the number of customers associated with each rate class.

Although the minimum size and zero-intercept studies classify meaningful portions of distribution plant as customer-related, to be allocated based on the number of customers, the equipment in those accounts does not vary directly with the number of customers. That is, costs in accounts 364-368 (poles, wires, and transformers) often do not increase when a customer is added to the grid. Rather, these costs tend to vary with customer demand.

For example, if the Company adds a new residential customer with a negligible level of demand in a populated area, the additional distribution costs to serve that customer—aside from dedicated customer infrastructure—would generally also be negligible, because no significant demand is being added by the new customer. If, however, the new customer were to add a substantial amount of additional demand, then distribution system upgrades would be required, increasing costs in accounts 364-368. Thus, these costs are primarily driven by demand, rather than by the number of customers. It is only when the distribution system must be expanded to a new geographic

[6] Lyons Direct Testimony p.12.
[7] NARUC Electric Manual at 20.

area that an incremental customer impacts distribution system costs independently from the customer's level of demand.

This example demonstrates that the presence of a residential customer does not necessarily impose additional distribution costs (apart from costs related to that customer's demand) unless the system must be expanded to a new geographic area. Thus, there is little justification for classifying costs in these accounts as customer-related.

Q If the system must be expanded to a new geographic area, will geography influence distribution costs more than the number of customers?

A Yes. The number of poles or miles of conductor and conduit required to serve a housing development is likely to vary more based on the distance of the development from other infrastructure, such as if the development is located within 0.1 versus 10 miles of the rest of the system, than based on whether there are 10 or 50 houses in the development.

Q Do the minimum size and zero-intercept studies account for geographic dispersion?

A No. These studies categorize costs as either related to demand or customer count, as does the COSS. There is no measure of geographic dispersion, and geography is not necessarily well-correlated with the number of customers. Therefore, the number of customers is not a very representative allocator.

Q Does industry literature consider customer count to be a good proxy for geographic dispersion?

A No. James Bonbright's widely recognized *Principles of Public Utility Rates* notes that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system."[8]

[8] Bonbright, James. *Principles of Public Utility Rates.* 1961, p. 348.

Q Is it particularly inappropriate to classify the primary electric system as customer-related?

A Yes. Primary distribution voltage is generally 1,000, 4,000, and 12,000 volts, while secondary distribution is generally under 477 volts. The residential customer class, for example, does not receive service directly at primary voltage.[9] Per the example above, it is unreasonable to suggest that the cause for installing primary equipment is the presence of a residential customer on the distribution system, regardless of that customer's demand, when residential customers likely receive service at a fraction of primary voltage.

Q Does the Company's minimum system also meet customers' demands?

A Yes. Any size of equipment in FERC accounts 365, 367, and 368 has load-carrying capacity and will necessarily serve a portion of customers' demand. In fact, the Company's minimum system is so extensive that it generally meets certain customer classes' peak demand requirements. For example, the minimum size transformer can meet 15-25 kVA of demand,[10] which likely meets almost all of the residential classes' maximum demand requirements.[11]

[9] Liberty response to Data Request CCM 0038.
[10] WP (Classifiers) – Accounts 364-368.xlsx, tab "368-Study."
[11] When asked for a summary of individual customer maximum demands for each customer class, Liberty stated that it "has not calculated individual customer maximum demands for each rate class nor were such individual customer maximum demands for each rate class utilized in the Company's class cost of service study." *See* Liberty response to Data Request CCM 0031. However, my experience in other jurisdictions indicates that even a 10 kVa transformer tends to exceed average residential peak demands.

Q If the minimum size equipment is large enough to accommodate certain customer classes' peak demands, would it be reasonable to classify such a large portion of the system as "customer-related"?

A No. Such a "minimum" system would exceed even the Company's intended theoretical scope, which is a system that "serve[s] minimum demand requirements of customers"[12] regardless of usage, not also a system that meets their *maximum* usage.

Q Do other limitations of the minimum size methodology also inflate the costs classified as customer-related?

A Yes. Further sources of imprecision in the Company's minimum system study arise due to reliance on blunt accounting cost records. Certain minimum system accounts include equipment that is constructed far upstream from individual customer loads and is thus typically built based on diversified, combined demands, not built based on the presence of individual customers. For example, plant accounting data does not distinguish trunkline, upstream, or backbone primary feeders[13] (which often connect high voltage distribution substations) from other conductors in FERC accounts 365 and 367. Thus, the Company includes these costs in its "minimum system," inappropriately treating them as customer-related even though they are likely driven by coincident peak demands at the substation. The substations themselves are classified as demand-related. Including these costs in the hypothetical minimum system inflates the costs that are classified as customer-related by an unknown amount.

[12] Lyons Direct Testimony p.19.
[13] Liberty response to Data Request CCM 0034.

Q What are the cost allocation impacts of using a study that inflates the costs classified as customer-related?

A Inflating the costs classified as customer-related—whether because of imprecise accounting data or by calculating a minimum system that may meet customer peak demands—has meaningful implications for the residential class. Customer-related costs are far more heavily allocated to residential customers compared to demand-related costs simply because the residential class has many more customer accounts than the other classes. Thus, assigning costs based on the number of customers will allocate the majority of these costs to the residential class. In contrast, the COSS assigns demand-related costs based on the relative class non-coincident peak demand (NCP), to which the residential class contributes a relatively lower level of demand.

Q Can you demonstrate how cost allocation varies when customer allocators are used rather than demand allocators?

A Yes. For accounts 364 – 368, using the number of customers to allocate costs results in over 80 percent of costs being assigned to residential customers, whereas using demand would allocate only 43-48 percent of costs to the residential class.[14]

Q Are the minimum size and zero-intercept methods unsound to use as the basis for determining cost causation?

A Yes. These methods require distinguishing a hypothetical system that either serves only customers, not their electricity demand, or only serves customers' minimum demand requirements. To create these imaginary systems, the Company makes subjective assumptions that oversimplify system engineering and impact the study results in

[14] Direct Schedule TSL-3 p.324.

unquantifiable ways, forming an unreliable basis on which the Company has assigned substantial costs among classes with significant impacts on revenue allocation and rate design.

Q Given that geography is not an allocation factor, that customer count is not a good proxy for geography, and that the minimum size and zero-intercept studies overstates the costs classified as customer-related, is it reasonable to treat all of FERC accounts 364-368 as demand-related?

A Yes.

Q What method do you recommend instead of the minimum size and zero intercept methods?

A I recommend classifying distribution costs using the Basic Customer Method. As described in the Regulatory Assistance Project's manual *Electric Cost Allocation for a New Era*, this method is used by states across the country and is intuitive and data-based, as it includes only costs that are directly related to the number of customers on the system. Specifically, the Basic Customer Method generally classifies only costs associated with services, meters, meter reading, and billing as customer-related.

Not only have utilities in numerous states used the Basic Customer Method,[15] but public utility commissions have also explicitly rejected the minimum system method or otherwise required that utilities classify primary and secondary distribution costs as 100 percent demand-related. For example:

- The Rhode Island Public Utilities Commission has repeatedly rejected the minimum

[15] For example, National Grid in Massachusetts does not use a minimum system study for classification. *See* Exhibit NG-PP-1 in D.P.U. 23-150 (November 16, 2023) at 18, stating "the Company has not performed a minimum system study in its last four distribution rate cases, or more, and…did not perform a minimum system study for this ACOSS."

system study.[16]

- The Maryland Public Service Commission has repeatedly rejected a minimum cost of service methodology.[17]
- The Arkansas Public Service Commission found that accounts 364–368 should be classified as 100 percent demand-related due to insufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes.[18]
- The Illinois Commerce Commission has repeatedly rejected the minimum distribution or zero intercept approach.[19]
- Washington administrative code specifies approved electric cost of service classification and allocation methodologies, requiring distribution substations, line transformers, and poles and wires to be classified as demand related.[20]
- The Michigan Public Service Commission rejected a party's recommendation to require a minimum size study, finding that both the minimum system and minimum intercept methods have serious conceptual flaws and imply a direct correlation between the number of customers and distribution system costs that does not exist.[21]
- Alaska administrative code prohibits customer-related costs from including "any portion of the distribution system costs, which will be considered and classified as

[16] Decision and Order, *In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution* Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).

[17] Order No. 83907, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base* Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland).

[18] Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).

[19] Lazar, J. et al., *Electric Cost Allocation for a New Era: A Manual.* Montpelier, VT: Regulatory Assistance Project (2020) (Hereafter: "RAP Electric Manual"). at 145

[20] Washington Administrative Code 480-85-060. https://app.leg.wa.gov/WAC/default.aspx?cite=480-85-060.

[21] Order, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, p.152. (December 22, 2021). Case No. U-20963 (Michigan Public Service Commission).

demand-related costs."[22]

Q If the Commission chooses not to approve the Basic Customer Method, would a hybrid classification method be more appropriate than Liberty's approach?

A Yes. If the Commission does not approve the Basic Customer Method, it is still possible to better align the minimum size and zero intercept studies with system cost drivers. In that case, I recommend that the Company classify primary distribution costs as 100 percent demand-related and only apply the minimum size or zero intercept methodology to secondary distribution costs, which are the lower-voltage lines that connect most customers to the grid. As described earlier, primary infrastructure is shared, is more likely to peak at the same time as system peaks, and is much higher-voltage than the customer-specific equipment (meters and services) directly serving the majority of electricity customers.

Q If the Commission approves any form of minimum size study, whether for only secondary plant, or for primary and secondary distribution plant, should any adjustments be made to recognize that the minimum system also meets all or a portion of customers' maximum demands?

A Yes. As recognized by the Staff of the Ontario Energy Board (OEB), "A Minimum System has a certain load carrying capability which can be viewed as being demand-related. As a result, the customer-related costs will have a demand component in them. If no adjustment is made, some customers (e.g. small users) may be allocated a disproportionate share of demand-related costs. If the Minimum System Method is

[22] 3 Alaska Admin. Code § 48.540.

preferred for categorization, Staff would recommend that distributors be required to also adjust for the [Peak Load Carrying Capacity] of the assumed Minimum System."[23]

OEB enshrined a peak load carrying capability (PLCC) adjustment in its report "provid[ing] the cost allocation methodology directions approved by the Board."[24]

Q Please explain how an adjustment should be made to account for the load carrying capacity of the assumed minimum system.

A A load carrying capacity adjustment reduces the non-coincident peak demands used for determining demand allocators by the amount of demand that can be served by the hypothetical minimum system. For example, if the minimum system can meet 1 kW of demand, then the residential class's NCP allocator is reduced by the product of 1 kW and the number of residential customers. In Ontario, the assumed load carrying capacity of the minimum system is 0.4 kW per customer.

Ontario continues to use this method, as the OEB has since reaffirmed the original report dictating that electricity distributors use the methodology in a 2007 Board report,[25] which the OEB again referenced in its Filing Requirements For 2024 Electricity Distribution Rate Applications.[26]

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[23] Ontario Energy Board. Cost Allocation Review: Staff Discussion Paper. September 2005. At 21-22. Available at https://www.oeb.ca/documents/cases/EB-2005-0317/staffdiscussionpaper_160905.pdf.

[24] Ontario Energy Board. Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors. September 2006. At 53-55. https://www.oeb.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf.

[25] Ontario Energy Board. Application of Cost Allocation for Electricity Distributors - Report of the Board. November 2007. At 1. https://www.oeb.ca/documents/cases/EB-2007-0667/Report_Cost_Allocation_Review_20071128.pdf.

[26] Ontario Energy Board. Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications. Chapter 2 - Cost of Service. December 2022. At 44. https://www.oeb.ca/sites/default/files/OEB-Filing-Reqs-Chapter-2-2023-Clean-20221215.pdf.

Q Have any other utilities implemented a load carrying capacity adjustment?

A Yes. For the most recent several rate cases, Northern States Power Company (dba Xcel Energy) in Minnesota and South Dakota[27] has assumed a load carrying capacity of 1.5 kW per customer for the minimum system and applied this adjustment to its distribution capacity cost allocation factors. In Minnesota, Xcel has used this methodology since before 2015, noting in its 2015 rate case that it "assumes the minimum-size distribution equipment used in the Minimum System Study has load-carrying capability of 1.5 kW per customer."[28] This is the same assumption that Xcel made in the rate case prior to 2015[29] and in the most recent 2024 rate case.[30]

National Grid recently proposed an even simpler approach in New York, allocating residential and small commercial customer classes $0 of the demand-related portion of the minimum-system distribution infrastructure, reasoning that "the minimum system would be able to meet the peak load for all or almost all customers in [the relevant classes]; that is, no further investment in higher capacity conductors would be required. Therefore, no demand-related costs for [FERC accounts 364-367] were allocated" to Residential, Residential Time of Use, and Small General Non-Demand classes.[31]

[27] Results of Xcel Energy Minimum Distribution System & Zero Intercept Studies. Docket No. EL22-017 - Application of Northern States Power Company dba Xcel Energy for Authority to Increase its Electric Rates. June 30, 2022. Exhibit___(CJB-1), Schedule 6 p.10.

[28] Direct Testimony and Schedules of Kelly A. Bloch. Docket No E002/GR-15-826. Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota. November 2, 2015. p.91-92. Provided as Attachment LFE-83-3.

[29] Results of Xcel Energy Minimum Distribution System & Zero Intercept Studies. Docket No E002/GR-15-826. Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota. November 2, 2015. Exhibit___(MAP-1), Schedule 11 p.9 (PDF p.131). Provided as Attachment LFE-83-4.

[30] Minimum System/Zero Intercept Study Results. Docket No. E002/GR-24-320 - Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota. November 1, 2024. Exhibit___(CJB-1), Schedule 8 p.9 (PDF p.126). Provided as Attachment LFE-83-1.

[31] Testimony of the Electric Rate Design Panel for Niagara Mohawk Power Corporation d/b/a National Grid in 24-E-0322. May 2024. At 33-34. The case resulted in a settlement that did not comment on COSS methodologies.

Q Does industry literature acknowledge that minimum-size distribution equipment can be viewed as a demand-related cost?

A Yes. The NARUC Cost Allocation Manual, which Liberty cites heavily to justify the minimum size method, notes that "when using the minimum-size distribution method…the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[32]

Q If the Commission approves use of Liberty's minimum system study, do you recommend a load carrying capacity adjustment?

A Yes. I recommend that Liberty implement a load carrying capacity adjustment for any FERC account classified using its minimum size study. Identifying the specific load carrying capacity of Liberty's minimum system is an exercise that would require thoughtful analysis from Liberty and other stakeholders. However, the approaches utilized in other jurisdictions can be applied to Liberty's COSS in the absence of a Company-specific calculation. I recommend that the Company credit each customer class with 1.5 kW per customer, applying the credit to the NCP demands used for determining minimum system demand allocators. Given that the capacity per customer of Liberty's minimum-sized line transformer appears to be well above 1.5 kW,[33] it would be reasonable to use at least a 1.5 kW credit per customer to develop revenue allocations until a more detailed analysis can be conducted.

[32] National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual.* 1992 at 95.

[33] Liberty's 98,271 line transformers serve 166,405 customers, meaning 1.69 customers per transformer (166,405 / 98,271). The weighted-average size of Liberty's minimum size transformer is 16 kva, meaning that the minimum transformer capacity per customer is 9.68 kva (16 / 1.69). *See* WP (Classifiers) - Accounts 364-368.xls, tab "368-Study."

Q If the Commission approves use of Liberty's minimum system study, do you recommend updating the cost accounting to allow for more granular classification and allocation?

A Yes. I recommend that the Commission require the Company to propose and commit to an approach for disaggregating its plant account data in order to distinguish between the costs of sub-transmission, trunkline, upstream or backbone primary feeders from the rest of plant in Accounts 365–367. This could be done in a compliance filing.

Q What is the COSS impact of using the basic customer distribution classification?

A Using the Basic Customer Method impacts the COSS output, which the Company uses to inform its proposed class revenue increases. Table 1 shows each customer class's rates of return (ROR) on its cost of service at current base rates under the Company's COSS[34] and the basic-customer COSS.[35] Under the Basic Customer Method, the residential TC-RG[36] ROR increases from 1.3 to 2, while the general service TC-LG ROR shrinks from 3 to 1.8. The Basic Customer Method reveals a higher cost to serve higher-usage classes due to their relatively higher contributions to class NCP demand.

Table 1. Rate of Return Under Different Classification Methods

Rate Class	Company's COSS	Basic Customer Method
NS-RG	2.9%	3.3%
TC-RG	1.3%	2.0%
TP-RG	0.0%	0.4%
NS-GS	4.1%	4.9%
TC-GS	5.2%	5.6%
TP-GS	-3.7%	-2.3%

[34] Direct Schedule TSL-3 p.3.
[35] Liberty Supplemental Response to CCM DR 0030 Attachment A.xls, tab "COSS Summary (Schedule 2)".
[36] Liberty's residential classes are: Non-Standard Residential (Schedule NS-RG), Time Choice Residential (Schedule TC-RG), and Time Choice Plus Residential (Schedule TP-RG). Most residential customers take service on Schedule TC-RG. *See* Lyons Direct Testimony p.6.

NS-LG	2.5%	1.3%
TC-LG	3.0%	1.8%
NS-SP	7.3%	6.5%
TC-SP	7.6%	6.7%
LP	6.2%	5.3%
TS	4.6%	4.6%
MS	14.1%	14.5%
SPL	1.6%	1.3%
PL	15.2%	14.6%
LS	-5.4%	-5.6%
Total Company	2.8%	2.8%

Q Should the results of the Basic Customer COSS impact the Company's revenue allocation?

A Yes. I discuss those impacts in Section IV.

Liberty Should Classify and Allocate Advanced Metering Infrastructure ("AMI") Meter Costs Based on Customer, Energy, and Demand

Q Describe the extent of AMI meter deployment in the Company's territory.

A AMI meters represent 81% of Liberty's metering rate base.[37]

Q How does the Company classify and allocate meter costs?

A The Company classifies meter costs, including AMI, or "smart" meters, as customer-related[38] and allocates them based on the current cost of meters in each rate class.[39]

[37] Direct Schedule TSL-3 p.381.
[38] Liberty response to Data Request CCM 0032.
[39] Lyons Direct Testimony p.26.

Q What are your concerns with Liberty's AMI meter classification and allocation approach?

A For traditional meters, Liberty's approach follows the principle of cost causation by recognizing that the weighted number of customers in a class drives traditional meter costs; however, AMI meters provide far more functionality than traditional meters. Liberty's approach does not reflect the realities of an evolving power system. Technology and cost responsibility are changing rapidly to meet evolving market demands and to support state policy goals. Technological advances are impacting the services provided on the power grid and how those services are provided, which requires utilities to re-evaluate cost allocation issues that may previously have been considered settled. Traditional cost of service techniques do not necessarily reflect the modern power system or a modernized understanding of cost causation on the system.

The Regulatory Assistance Project explains that the main purpose of meters was once customer billing, but that "advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and line loss reduction, which provides a system energy benefit. This means the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs."[40]

Q Do Liberty's new AMI meters enable services beyond customer-related functions?

A Yes. Liberty's AMI can enable significant new functionality beyond the analog metering associated with traditional meters. AMI can enable operational benefits, such as avoided transformer failures through better monitoring of customer load, reduced loss factor

[40] RAP Electric Manual at 18.

though voltage optimization, reduced need for distribution capital investments, reduced system losses and reduced capital investments – including due to Time of Use rate designs, and better information to support conservation efforts and identify devices or equipment that are inefficient.

Q Do these new functionalities and their associated benefits change cost causation for AMI meters compared to traditional meters?

A Yes. The potential operational improvements extend the role of AMI meters beyond traditional metering, which do not enable energy savings and demand reductions in this way. Cost causation for AMI investments is dictated by those services and benefits.

Q How do you recommend that Liberty classify AMI meter costs?

A The Company should classify AMI meter costs as a combination of customer, demand, and energy, because AMI meters provide services and benefits that can be categorized into each of the three cost drivers. Based on the benefits quantified in other jurisdictions, I recommend a classification approach that treats AMI meter costs as 50% customer-related, 25% energy-related, and 25% demand-related.

Q Have other Commissions approved similar AMI meter classifications?

A Yes. The Maryland Public Service Commission approved "a benefits approach for allocating AMI costs among rate classes" in 2016, when it approved a proposal to assign 25% of AMI costs using a customer-based allocator, 37.5% using a demand-based allocator, and 37.5% using an energy-based allocator in Pepco's distribution rate case.[41] The approved proposal was based on the fact that an early report on AMI benefits

[41] In the Matter of the Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (Hereafter, "MD PSC, Case No. 9418"). Order No. 87884. November 15, 2016. https://www.psc.state.md.us/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf. At 105-106.

assigned just over 75 percent of the benefits to energy and demand management outcomes, justifying a customer, demand, and energy based allocation.[42] The PSC concluded that the "hybrid approach most fairly spreads the costs and related benefits of AMI throughout the Pepco service territory."[43]

Q Does Maryland continue to use a composite allocator for AMI meters?

A Yes. The PSC ordered Baltimore Gas and Electric Company ("BGE") to update its electric AMI benefit analysis in its 2023 rate case to ensure that the AMI allocators reflect updated benefit weights. BGE analyzed six years of data and proposed to allocate 56% of AMI meters based on the replacement cost of AMI meters (customer), 26% based on NCP (demand), and 18% based on MWH sales (energy).[44]

Q Has the Colorado Public Utilities Commission also approved AMI meter classification as more than customer-related?

A Yes. In Proceeding No. 23AL-0243E (and in at least two prior rate cases), Public Service Company of Colorado functionalized 17% of Advanced Meter costs as secondary distribution (classified as demand-related), with the remaining 83% functionalized as metering (classified as customer-related).[45]

In its February 2024 decision, the Commission found that "there are system-wide benefits of AMI that should be better reflected in the allocation" and therefore directed the Company to "provide a more robust analysis of these costs and identification of the scale

[42] MD PSC, Case No. 9418. Direct Testimony of Shelley Norman. July 6, 2016. https://webpscxb.psc.state.md.us/DMS/case/9418 Item No. 33. At 21-23.
[43] MD PSC, Case No. 9418. Order No. 87884. November 15, 2016. https://www.psc.state.md.us/wp-content/uploads/Order-No.-87884-Case-No.-9418-Pepco-Rate-Case-1.pdf. At 106.
[44] Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan. Case No. 9692. Direct Testimony of April M. O'Neill. February 17, 2023. https://webpscxb.psc.state.md.us/DMS/case/9692 Item No. 1. At 15-17.
[45] Colorado Public Utilities Commission Docket No. 23AL-0243E. Rebuttal Testimony Derek S. Klingeman, p.29-31.

and proper allocation of benefits associated with AMI when it files its next Phase II rate case."[46]

Q What is the likely class impact of your recommended AMI meter classification?

A As with my Basic Customer Method recommendation, this alternative classification reduces the costs treated as customer-related, in this case treating portions as energy and demand related. Demand and energy allocators tend to allocate fewer costs to small consumers and greater costs to larger consumers than the customer allocator does, due to larger users' higher utilization of the power system. As previously mentioned, using the number of customers to allocate costs results in over 80% of costs being assigned to residential TC-RG customers, whereas using demand would allocate only 43-48% of costs to the residential class. Using energy (annual sales) would allocate 41% of costs to the residential class.[47]

Q Have you implemented your proposal in the Company's COSS to determine its impact on Liberty's COSS results?

A I have attempted to make such change, but have not been able to properly modify the model. Thus, the Company is best qualified to adapt its model to include this new classification and allocation approach if the Commission approves it. As discussed above, the new approach would allocate fewer costs to small consumers and greater costs to larger consumers than the customer allocator does, due to larger users' higher utilization of the power system and relatively fewer customers.

[46] Colorado Public Utilities Commission Docket No. 23AL-0243E. February 7, 2024. 2023 CO Phase II Electric Rate Review Decision No. C24-0117, p.23.
[47] Direct Schedule TSL-3 p.324

IV. REVENUE ALLOCATION

Q How does Liberty determine what revenue increase to apportion to each customer class?

A The Company used the results of its COSS to determine what the revenue requirement increase would be for each rate class if each class were to achieve an Equalized Rate of Return (EROR) on its purported cost of service. Liberty compared this increase to the revenue requirement increase for each rate class if each class got a uniform increase in revenues – of 29.6%, equal to the overall system increase – with no movement toward EROR. Ultimately, in consideration of rate continuity and movement to cost-based rates, Liberty proposed class revenue targets for each rate class that represent a 10% movement toward EROR from the uniform revenue increase.[48]

Q Do you support the Company's revenue requirement allocation methodology?

A Yes. The Company has exercised judgement when using its COSS to inform revenue allocation and rate design, recognizing the importance of gradualism and rate stability, as well as the inherently imprecise nature of a COSS, as I mentioned earlier.

Q Do you recommend updating revenue allocations based on your COSS results?

A Yes. I recommend updating Liberty's revenue allocations based on my COSS recommendations to use the Basic Customer Method for distribution cost classification, and to use customer, energy and demand allocators for AMI meters. Although I do not have a COSS result for the latter recommendation, I would expect it to amplify the trend of my other recommendation and therefore directionally align with the COSS results.

[48] Lyons Direct Testimony, p.30.

Table 2 compares class revenue increases based on the Company's COSS[49] and based on the basic-customer COSS,[50] both derived using the Company's revenue allocation methodology. While the Company's COSS deemed the Residential TC-RG class to require a 43.2% increase, or 1.46 times the overall percentage increase in revenues, to achieve full movement to EROR, a COSS that used the Basic Customer Method deems the Residential TC-RG class to require a 36.4% increase, or 1.23 times the overall percentage increase in revenues, to achieve full movement to EROR. After using the Company's revenue allocation methodology on the Basic Customer Method COSS results, the Residential TC-RG class would be assigned a 30.3% increase, compared to Liberty's proposed 31%.

[49] Direct Schedule TSL-4.
[50] Liberty Supplemental Response to CCM DR 0030 Attachment A.xls, tab "Class Revenues (Schedule 4)."

Table 2. Class Revenue Increases Using Liberty's Revenue Allocation Method

Rate Class	Company	Basic Customer
NS-RG	29.5%	29.2%
TC-RG	31.0%	30.3%
TP-RG	33.0%	32.3%
NS-GS	28.6%	28.0%
TC-GS	27.8%	27.6%
TP-GS	37.6%	33.7%
NS-LG	30.0%	31.4%
TC-LG	29.6%	30.8%
NS-SP	26.7%	27.1%
TC-SP	26.5%	27.0%
LP	27.2%	27.7%
TS	27.7%	27.7%
MS	24.4%	24.3%
SPL	32.6%	33.0%
PL	23.9%	24.1%
LS	57.3%	58.7%
Total Company	**29.6%**	**29.6%**

V. RATE DESIGN

Q Describe the Company's residential fixed charge proposal.

A The Company proposes to increase the residential fixed charge from $13 to $16, or by 23%. The Company justifies this increase as a "step towards full recovery of the Company's fixed costs," claiming that its COSS shows customer-related costs of $30.81 per customer per month.[51]

Q Do you have concerns about the Company's customer charge proposal?

A Yes. First, when updated to reflect the Basic Customer Method, Liberty's COSS instead shows customer-related costs of $16.85 per customer per month,[52] contradicting the

[51] Lyons Direct Testimony p.31.
[52] Liberty Supplemental Response to CCM DR 0030 Attachment A.xls, tab "Customer Costs (Schedule 5)."

Company's claim that its proposed customer charge "is well below the underlying cost of service."[53] This customer-related unit cost would also be lower if Liberty classified AMI meters as energy-, demand-, and customer-related, as I have recommended.

Second, raising the customer charge reduces customers' ability to control their own bills, by increasing the fixed portion of the monthly electric bill, over which customers have no control even if they can reduce their electricity consumption. The impact is more acute for low-usage customers whose bills are relatively smaller and therefore more influenced by the customer charge. Low-income customers are also more likely to be low-usage and have less ability to pay higher bills.

Third, a higher fixed charge also means a lower volumetric charge than there otherwise would have been. Relatively lower volumetric charges paired with higher fixed charges can discourage conservation and render energy efficiency and load management investments less cost-effective. This reduces the value to customers of reducing their energy consumption and therefore increases the payback periods for energy efficiency investments.

Q Demonstrate that the rate impact of the Company's proposals is more acute for low-usage customers.

A The Company calculates that the overall revenue increase will increase the monthly bill of a Residential customer using 1,000 kWh per month by 31.05%.[54] However, the same rate increases for a Residential customer using 400 kWh per month would increase their monthly bill by 36.37%,[55] due to the higher proportion of their bill spent on the fixed

[53] Lyons Direct Testimony p.31.
[54] Lyons Direct Testimony p.32.
[55] EDE MO 2024 COSS Model - (CONFIDENTIAL) 2-26-25.xls, tab "MFR Schedule 3 pg 1 (Base)", modified to reflect 400kWh/month rather than 1,000.

charge. Low-usage, low-income customers have minimal tools to mitigate the rate impacts of an increased customer charge and will be disproportionately harmed by Liberty's proposal.

Q Is there empirical evidence demonstrating a relationship between energy usage and income?

A Yes. EIA's 2020 Residential Energy Consumption Survey shows a clear and consistent relationship between household income and energy usage. This relationship is apparent in every region of the country, including the Midwest (which includes Missouri), as indicated in Table 3 below.

Table 3. Household Income and Electricity Consumption, Midwest Region, 2020[56]

Income	Per household electricity consumption (million Btu)[57]
$5,000-$9,999	25.2
$10,000-$19,999	25.1
$20,000-$39,000	29
$40,000-$59,000	29.7
$60,000-$99,000	34.3
$100,000-$149,000	38.9
$150,000 or more	46.7

Q Do you support the Company's proposed residential fixed charge increase?

A No. I recommend that the Company maintain its current $13.00 monthly fixed charge and instead increase the residential volumetric rate as necessary in order to achieve the required revenue requirement increase.

[56] https://www.eia.gov/consumption/residential/data/2020/c&e/pdf/ce2.3.pdf

[57] Energy consumption is expressed in Btu in the RECS tables and analyses to allow for consumption comparisons between fuels that are measured in different units. https://www.eia.gov/consumption/residential/terminology.php.

VI. CONCLUSION

Q Does this conclude your testimony?

A Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in Its Missouri Service Area.	)))	**No. ER-2024-0261**

AFFIDAVIT OF CAROLINE PALMER

I, the undersigned, being duly sworn, state that my name is Caroline Palmer, and that the foregoing Direct Testimony of Caroline Palmer, including attachments, was prepared by me on behalf of the Consumers Council of Missouri. This testimony was prepared in written form for the purpose of its introduction into evidence in the above utility case at the Missouri Public Service Commission.

I hereby swear and affirm that the attached testimony is true and correct to my best knowledge, information, and belief, and I adopt said testimony as if it were given under oath in a formal hearing.

Caro Palmer

Caroline Palmer

Subscribed before me on this 21 day of July, 2025:

Eunice DePena
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 27, 2029

Eunice DePena

Attachment CP-1

Caroline Palmer, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-973-1715
cpalmer@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge, MA. *Principal Associate*, June 2024 – present.

- Conduct analysis and provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings, on topics including electric utility class cost of service, revenue allocation, advanced rate design, avoided cost methodology, and distributed generation interconnection and planning.

Strategen Consulting, Oakland, CA. *Senior Manager*, 2024; *Manager,* 2023 - 2024; *Senior Consultant*, 2021 - 2022; *Consultant*, 2019 - 2021.

- Conducted analysis and provided expert witness and consulting services to state regulatory commissions, state consumer advocates, and non-profits to advance the public interest in regulatory decision-making around electricity service, pricing, and decarbonization.

Metropolitan Area Planning Council Boston, MA. *Clean Energy Fellow*, 2017.

- Provided technical assistance to Massachusetts local government on renewable energy technology and energy planning.

Fulbright Foundation Athens, Greece. *Fulbright Research Fellow*, 2015 – 2016.

- Designed and conducted original, independent research on renewable energy policymaking and implementation in the context of Greece's severe economic crisis

Meister Consultants Group (now Cadmus), Boston, MA. *Analyst,* 2014 – 2015.

- Performed research and writing for renewable energy policy design, analysis, and implementation.

EDUCATION

University of California, Berkley, CA
Master of Public Policy – Energy Policy, 2019

Georgetown University, Washington, DC
Bachelor of Science in Foreign Service – Science, Technology, and International Affairs, 2013

TESTIMONY

Michigan Public Service Commission. (U-21859). Direct Testimony and Rebuttal Testimony of Caroline Palmer (data center tariff design) regarding Application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD. On behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan (CUB), collectively "MNSC." June 12, 2025 and July 9, 2025.

Connecticut Public Utilities Regulatory Authority (24-10-04) Direct Testimony, Surrebuttal Testimony, and Cross-examination of Caroline Palmer (Cost-of-Service Study/Rate Design) regarding Application of The United Illuminating Company to Amend Its Rate Schedules. On behalf of The Office of Consumer Counsel. February 13, 2025, March 24, 2025, and May 6, 2025.

New Hampshire Public Utilities Commission (DE 24-070) Direct Testimony and Cross-examination of Caroline Palmer (Cost-of-Service Study/Rate Design) regarding Public Service Company of New Hampshire d/b/a Eversource Energy Request for Change in Distribution Rates. On behalf of the NH Office of Consumer Advocate. January 23, 2025 and June 4, 2025.

Massachusetts Department of Public Utilities (D.P.U. 24-195, 24-196, 24-197) Direct and Surrebuttal Testimonies of Caroline Palmer and Thanh Nguyen addressing the EV Infrastructure Program mid-term modification filings from the electric distribution companies. On behalf of The Massachusetts Office of the Attorney General. April 4, 2025 and May 27 2025.

Missouri Public Service Commission (WR-2024-0320). Direct Testimony of Caroline Palmer (Cost-of-Service Study/Rate Design) regarding Missouri-American Water Company's Request for Authority to Implement a General Rate Increase for Water and Sewer Service. On behalf of Consumers Council of Missouri. December 20, 2024.

Missouri Public Service Commission (ER-2024-0319). Direct Testimonies and Surrebuttal Testimony of Caroline Palmer (Revenue Requirement and Cost-of-Service Study/Rate Design) regarding Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service. On behalf of Consumers Council of Missouri. December 3, 2024, December 17, 2024, and February 14, 2025.

Nova Scotia Utility and Review Board (M11874). Direct Testimony of Caroline Palmer regarding costs incurred to implement the Renewable to Retail market. On behalf of Counsel to Nova Scotia Utility and Review Board. November 1, 2024.

Maine Public Utilities Commission (Docket No. 2024-00137). Direct Testimony and Cross-examination of Caroline Palmer and Eric Borden regarding Stranded Cost Rate Design. On behalf of the Maine Office of the Public Advocate. October 1, 2024 and January 10, 2025.

New York Public Service Commission (Cases 24-E-0322 & 24-G-0323): Direct Testimony of Caroline Palmer, Melissa Whited, and Ben Havumaki regarding the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service. On behalf of the

Utility Intervention Unit (UIU) of the New York Department of State's Division of Consumer Protection. September 26, 2024.

Massachusetts Department of Public Utilities (D.P.U. 23-150): Direct Testimony, Surrebuttal Testimony, and Cross-examination of Caroline Palmer and Ron Nelson regarding Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan. On behalf of the Massachusetts Office of the Attorney General. March 29, 2024, May 3, 2024, and May 20, 2024.

North Carolina Utilities Commission (Docket No. E-7, Sub 1276): Direct Testimony of Caroline Palmer regarding the Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation. On behalf of the North Carolina Attorney General's Office. July 19, 2023.

Oklahoma Corporation Commission (Case No. PUD 2022-000093.): Adoption of Direct Testimony and Cross-examination regarding the Application of Public Service Company of Oklahoma, for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service in the state of Oklahoma and to approve a formula-based rate proposal. On behalf of AARP. May 22, 2023.

Maine Public Utilities Commission (Case No. 2022-00152): Direct Testimony and Surrebuttal Testimony of Caroline Palmer, Nikhil Balakumar, and Ron Nelson regarding the Central Maine Power Company's request for Approval of a Rate Change - 307 (7/30/23). On behalf of the Maine Governor's Energy Office. December 2, 2022 and April 6, 2023.

Massachusetts Department of Public Utilities (D.P.U. 21-91): Direct Testimony and Cross-examination of Caroline Palmer and Ron Nelson regarding the Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and EV Demand Charge Alternative Proposal. On behalf of the Massachusetts Office of the Attorney General. January 5, 2022, and March 22, 2022.

Massachusetts Department of Public Utilities (D.P.U. 21-90): Direct Testimony and Cross-examination of Caroline Palmer and Ron Nelson regarding the Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III EV Market Development Program and EV Demand Charge Alternative Proposal. On behalf of the Massachusetts Office of the Attorney General. January 5, 2022, and March 22, 2022.

Massachusetts Department of Public Utilities (D.P.U. 21-92): Direct Testimony and Cross-examination of Caroline Palmer and Ron Nelson regarding the Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its EV Infrastructure Program, EV Demand Charge Alternative Proposal, and Residential EV Time-of-Use Rate Proposal. On behalf of the Massachusetts Office of the Attorney General. January 5, 2022, and March 22, 2022.

PUBLICATIONS

Yuang, C., M. Whited, T. Nguyen, S. Schadler, R. Anderson, W. Dejeanlouis, C. Palmer, C. Mattioda, A. Glaser Schoff, S. Koester, J. Hittinger, P. Eash-Gates. 2024. *Utility Engagement Playbook for Industrial Customers: Addressing Power Sector Barriers to Electrification.* Synapse Energy Economics and World Wildlife Fund for Renewable Thermal Collaborative.

Palmer, C. 2019. *Using Low Carbon Fuel Standard Proceeds from EV Adoption to Improve the Efficiency of Electricity Rates.* Berkeley Public Policy Journal.

PRESENTATIONS

Palmer, C. 2025. Large Load Tariffs – Current Efforts to Minimize Risk to Consumers. NASUCA Mid-Year Meeting. Columbus, OH.

Palmer, C. 2022. Utility Transportation Electrification from a Consumer Advocate Perspective. NASUCA Mid-Year Meeting. Indianapolis, IN.

Palmer, C. 2017. Integration of renewable energy in Greek energy markets: A case study. 2nd HAEE International Conference. Athens, Greece.

Resume last updated July 2025

Attachment CP-2

The Empire District Electric Company d/b/a Liberty
Case No. ER-2024-0261
Consumers Council of Missouri Data Request - 0030

Data Request Received: 2025-06-20
Request No. 0030
Submitted by: John Coffman, john@johncoffman.net

Supplement Response Date: 2025-07-17
Witness/Respondent: Tim Lyons

REQUEST:

Refer to Direct Testimony of Timothy S. Lyons and the Company's COSS. In live, unlocked Excel file format with all links and formula intact, please provide an alternate version of the COSS for each of the following scenarios:

a. In which FERC Accounts 364-368 are classified as 100% demand-related.

b. In which the primary portion of FERC Accounts 364-368 are classified as 100% demand-related.

SUPPLEMENTAL RESPONSE 07/17/2025:

ATTACHMENTS ARE CONFIDENTIAL PURSUANT TO 20 CSR 4240-2.135(2)(A)5

The Company received feedback from CCM requesting a review its previous DR response. After considering CCM's input and additional guidance, the Company has revised the original documents to reflect the following updates.

Changes to CCM DR 0030 Attachment A –

In tab "Classif-Dashboard", changed Accumulated Depreciation for the following accounts to classify Primary and Secondary Distribution based on demand "DEM"

- Row 81 – Poles
- Row 82 – Overhead Conductors
- Row 83 – Underground Conductors
- Row 84 – Transformers

In tab “Classif-Dashboard”, changed Operations and Maintenance Expenses for the following accounts to classify Primary and Secondary Distribution based on demand “DEM”

- Row 152 – Overhead line expenses (583)
- Row 153 – Underground line expenses (584)
- Row 164 – Maintenance of Overhead line expenses (593)
- Row 165 – Maintenance of Underground line expenses (594)
- Row 166 – Maintenance of Line Transformer expenses (595)

In tab “Classif-Dashboard”, changed Depreciation Expenses for the following accounts to classify Primary and Secondary Distribution based on demand “DEM”

- Row 215 – Poles
- Row 216 – Overhead Conductors
- Row 217 – Underground Conductors
- Row 218 – Transformers

Changes to CCM DR 0030 Attachment B –

In tab “Classif-Dashboard”, changed Accumulated Depreciation for the following accounts to classify Primary Distribution based on demand “DEM”

- Row 81 – Poles
- Row 82 – Overhead Conductors
- Row 83 – Underground Conductors

In tab “Classif-Dashboard”, changed Operations and Maintenance Expenses for the following accounts to classify Primary Distribution based on demand “DEM”

- Row 152 – Overhead line expenses (583)
- Row 153 – Underground line expenses (584)
- Row 164 – Maintenance of Overhead line expenses (593)
- Row 165 – Maintenance of Underground line expenses (594)

In tab “Classif-Dashboard”, changed Depreciation Expenses for the following accounts to classify Primary Distribution based on demand “DEM”

- Row 215 – Poles
- Row 216 – Overhead Conductors
- Row 217 – Underground Conductors

a. Please refer to Supplemental Response to CCM DR 0030 Attachment A CONFIDENTIAL.xlsx
b. Please refer to Supplemental Response to CCM DR 0030 Attachment B CONFIDENTIAL.xlsx.

ORIGINAL RESPONSE 07/10/2025:

ATTACHMENTS ARE CONFIDENTIAL PURSUANT TO 20 CSR 4240-2.135(2)(A)5

a. Please refer to Response to CCM DR 0030 Attachment A CONFIDENTIAL.xlsx
b. Please refer to Response to CCM DR 0030 Attachment B CONFIDENTIAL.xlsx.

Data Request Received: 2025-06-20
Response Date: 2025-07-10
Request No. 0031
Witness/Respondent: Tim Lyons
Submitted by: John Coffman, john@johncoffman.net

REQUEST:

Refer to Direct Testimony of Timothy S. Lyons and the Company's COSS. Using the most granular data available, provide a summary of individual customer maximum demands for each customer class (ex: in the form of a box and whisker plot, or boxplot).

RESPONSE:

The most granular data available to calculate individual customer maximum demands for each rate class are in the following support files:

WP (Demand) - Supporting Data.xlsx
WP (Annualization) - Residential (CONFIDENTIAL).xlsx
WP (Annualization) - Small Primary (CONFIDENTIAL).xlsx
WP (Annualization) - General Service (CONFIDENTIAL).xlsx
WP (Annualization) - Large General Service (CONFIDENTIAL).xlsx

The Company has not calculated individual customer maximum demands for each rate class nor were such individual customer maximum demands for each rate class utilized in the Company's class cost of service study.

Data Request Received: 2025-06-20
Response Date: 2025-07-10
Request No. 0032
Witness/Respondent: Tim Lyons
Submitted by: John Coffman, john@johncoffman.net

REQUEST:

Refer to Direct Testimony of Timothy S. Lyons at 21 and Section VI, referring to rates that vary by time period, and the Company's SCHEDULE TC-RG.

a. Define automated metering infrastructure (AMI) device.

b. Describe the extent of advanced/automated metering infrastructure installations in the Company's territory. What portion of each customer class has AMI installations? If the answer is less than 100%, explain if the Company plans to roll out advanced metering to all customers, and provide the timeline for the rollout.

c. Does the Company classify, or intend to classify, automated metering infrastructure (AMI) devices as anything other than customer-related? (currently, "meter cost, meter installation and service cost investments were classified as customer-related").

d. Provide the docket number and Commission order approving the Company's AMI investment.

RESPONSE:

a. Advanced Metering Infrastructure (AMI) meters, often referred to as "smart meters", are digital meters with advanced features and capabilities beyond traditional electricity meters. AMI is an integrated system of meters, communications networks, and data management systems that enables two-way communication between utilities and customers. The Company's AMI investment will enable monthly meter reads to be conducted remotely, avoiding the need to send a technician to read each meter on premise. AMI improves the efficiency, quality, and range of services provided to customers by providing better data about energy usage so customers can be more informed and make choices about how they consume their energy.
b. AMI is available now to all customers.
c. The Company classified meter costs including AMI costs in its class cost of service study as customer-related.
d. Case Nos. ER-2019-0374 and ER-2021-0312.

The Empire District Electric Company d/b/a Liberty
Case No. ER-2024-0261
Consumers Council of Missouri Data Request - 0034

Data Request Received: 2025-06-20 | Response Date: 2025-07-10
Request No. 0034 | Witness/Respondent: Tim Lyons
Submitted by: John Coffman, john@johncoffman.net

REQUEST:

Refer to Direct Testimony of Timothy S. Lyons, regarding the minimum-size study.

a. Has the Company included subtransmission, trunkline, upstream, or backbone primary feeders in the conductor/circuit count that it multiplied by the minimum size cost for FERC Account 365, 366, or 367?

b. Does the plant accounting data for FERC Account 365, 366, or 367 isolate the costs of trunkline, upstream or backbone primary feeders from the rest of the plant in those accounts?

RESPONSE:

a. Please refer to the Company's previously provided file, WP (Classifiers) – Accounts 364-368. The file reflects assets booked to the respective FERC accounts 365, 366, and 367.
b. No, the referenced costs of trunkline, upstream, or backbone primary feeders are not isolated from the rest of the plant in those accounts.

The Empire District Electric Company d/b/a Liberty
Case No. ER-2024-0261
Consumers Council of Missouri Data Request - 0038

Data Request Received: 2025-06-20 | Response Date: 2025-07-10
Request No. 0038 | Witness/Respondent: Tim Lyons
Submitted by: John Coffman, john@johncoffman.net

REQUEST:

Refer to Direct Testimony of Timothy S. Lyons at 16.

a. What voltage levels constitute primary voltage?

b. What voltage levels constitute secondary voltage?

c. Confirm that residential customers do not receive service at primary voltages.

RESPONSE:

a. Primary voltage generally reflects 12 kV, 4 kV, and 1 kV voltage levels, according to Exhibit 1 of the Company's 2020 Analysis of System Losses published in July 2022 by Management Applications Consulting, Inc.
b. Secondary voltage generally reflects 120/240 V to 477 V voltage levels, according to Exhibit 1 of the Company's 2020 Analysis of System Losses published in July 2022 by Management Applications Consulting, Inc.
c. The Company is not aware of any residential customers taking service at primary voltages.