Exhibit No.:	____________
Issue(s):	CCOS/Cost Allocation
Witness/Type of Exhibit:	Nelson/Direct
Sponsoring Party:	Public Counsel
Case No.:	ER-2026-0143

DIRECT TESTIMONY

OF

RON NELSON

Submitted on Behalf of the Office of the Public Counsel

EVERGY METRO, INC. D/B/A
EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

*** ____ ***
Denotes Highly Confidential Information that has been redacted

** ____ **
Denotes Confidential Information that has been redacted.

July 14, 2026

PUBLIC

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

RON NELSON

EVERGY METRO

CASE NO. ER-2026-0143

I. Introduction

Q. Please state your name, business address and current position.

A. My name is Ron Nelson. I am a Founding Partner of Current Energy Group ("CEG"). My business address is 4764 E Sunrise Drive Unit #508, Tucson, AZ 85718.

Q. On whose behalf are you submitting testimony?

A. I am filing testimony on behalf of the Missouri Office of Public Council ("OPC").

Q. Have you previously submitted testimony before the Missouri Public Service Commission ("PSC" or "Commission")?

A. No, I have not.

Q. Have you ever testified before any other state Public Utility Commissions?

A. Yes. I have testified in over 95 proceedings in Alaska, Arizona, Colorado, Georgia, Florida, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Nevada, New Hampshire, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Carolina, Utah, Virginia, Wisconsin, and Vermont. Among the issues covered in these proceedings were marginal and embedded cost of service studies ("COSS"), revenue allocation, rate design, load management, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, DER interconnection, flexible interconnection, pre-emptive

DER and load upgrades, DER compensation, DER integration, EV infrastructure investments, pilot frameworks, automated metering infrastructure, prudence review, distribution system planning, capital investment plan review, and smart inverter integration, among other topics.

I have also advised the Connecticut, Colorado, Hawaii, and Kentucky state utility commissions and have testified and supported clients at the Federal Energy Regulatory Commission ("FERC").

Q. Have you testified previously on large load tariffs and related cost of service issues?

A. Yes, I recently testified on the large load tariffs of Dominion Energy ("Dominion"), Appalachian Power Company, PPL Electric Utilities Corporation, Duke Energy Florida, and Wisconsin Energy, and I have assisted or testified on large load issues in Arizona, Colorado, New Mexico, Illinois, North Carolina, South Carolina, Utah, Nevada, Oregon, and before FERC. I am also the Georgia Public Service Commission's expert on large load contracts, cost allocation, and rate design.

Q. Please describe your educational and occupational background.

A. I have worked with numerous consumer advocates, nongovernmental organizations, utilities, and public utility commissions on issues related to cost-of-service modeling, rate design, grid modernization, distributed energy resource valuation and integration, and performance-based regulation. CEG specializes in providing clients regulatory services in the areas of cost-of-service modeling, regulatory innovation, performance-based regulation, distributed energy resources ("DER"), rate design, renewable program development, grid modernization, new grid technologies, integrated resource planning, and electric vehicles.

Prior to founding CEG, I briefly worked for my own sole proprietorship and at a consulting firm in various roles for six years, including as a Senior Director.

Prior to 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led that office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University, where I also minored in Mathematics. My curriculum vitae is attached as Exhibit RN-1.

Q. Please describe the purpose of your testimony.

A. My testimony evaluates the merits and deficiencies of the Company's COSS model, with a particular focus on how Evergy Missouri Metro ("EMM" or "Company") accounts for emerging Schedule LLPS customers in its costs of service model. Based on my evaluation, I make recommendations to account for expected revenues from Schedule LLPS customers not included in the test year and to better align the Company's cost allocation methodology for production and transmission with economic theory. I close by discussing the Company's residential rate design proposal

Q. Please summarize your testimony and recommendations to the Commission.

A. In my testimony, I make the following recommendations to the Commission:

1. Direct EMM to properly match the Schedule LLPS rate class with the financial impacts that these customers will be expected to have on the Company's

generation and transmission needs. One way to accomplish that goal is to increase EMM's COSS adjustment regarding Schedule LLPS revenues from ***____ ***. Another option is for the Commission to establish a mechanism whereby any Schedule LLPS revenues that exceed the pro-forma adjustment of ***__________ *** included in the Company's COSS model would be refunded to all other rate classes in the following year.

2. Direct EMM to change its cost allocation methodology for production and transmission costs to the Probability of Dispatch ("POD") model.
3. Reject the Company's proposal to increase the customer charge and maintain the current charge of $12.00 per month.

II. COSS and Large Load Policy Issues

Q. What is the purpose of this section of your testimony?

A. In this section, I introduce the policy background and considerations for the Commission regarding large loads and their impacts on cost allocation in a rate case. I then discuss a mismatch in EMM's cost of service study related to incurring costs to serve large load customers in rate base, but failing to account for future revenue, leading to higher rates for other customer classes. To remedy this mismatch, I propose either including expected future revenues from large load customers as a pro forma adjustment or implementing a true-up mechanism to refund revenues above those included in this rate case from large load customers to other customer classes.

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A. Policy Background Regarding Large Load Power Service Customers

Q. What is your understanding of SB 4 as it pertains to large loads as a non-lawyer expert in this field?

A. Senate Bill 4 ("SB4") was passed by the Missouri legislature and signed by Governor Kehoe in 2025. Among other provisions, this legislation requires electrical corporations with greater than 250,000 customers, such as EMM, to submit tariffs for large load customers with a peak demand over 100 MW to the Commission. The legislation also requires the Commission to ensure that these tariffs and schedules "reasonably ensure that the rates of customers who are reasonably projected to have annual peak demands below the above-referenced levels will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[1]

Q. How has the Commission responded to this new requirement for EMM?

A. In response to this requirement, the Commission recently approved Schedule Large Load Power Service ("LLPS") in Case No. EO-2025-0154. In approving this new tariff, the Commission found that it contained safeguards that ensure that customers over 75 MW pay their share of costs while enabling Missouri to compete for transformational loads.[2]

Q. Is Schedule LLPS distinct from EMM's other large customer classes?

A. Yes, it is. In approving Schedule LLPS the Commission also limited the Company's existing large customer tariffs to those customers with peak loads under 75 MW or existing

[1] Missouri Stat 393.130(7)
[2] Case No. EO-2025-0154, Report and Order at 25. November 13, 2025

customers of EMM. Those customers may continue to take service under EMM's Large Power Service ("Schedule LPS") tariff.

Q. Does Schedule LLPS specify pricing for EMM's large load customers?

A. Yes, it does. The Non-Unanimous Global Stipulation and Agreement, approved by the Commission in Case No. EO-2025-0154, contains initial pricing for Schedule LLPS that will remain in effect until there is at least one Schedule LLPS customer with a capacity of 75 MW or greater reflected in the test year and captured in the CCOS study bill determinants in a future rate case.[3]

Q. What is that pricing based on?

A. While it is difficult to determine the exact source of pricing for Schedule LLPS, as it was agreed to in a settlement, I assume it is generally based on Schedule LPS, as the customer charge is the same between the two tariffs and the pricing structure is similar. Costs for Schedule LPS are allocated using an average embedded cost approach.

Q. Can you explain how the average embedded cost of service method works regarding large loads?

A. At a high level, under an embedded cost of service approach, a utility determines its total revenue requirement both for new investments required to serve large loads as well as all of its historical investments in the electric grid, functionalizes those costs into categories such as production, transmission, and distribution costs, and allocates those costs to each customer class using allocation factors. Cost allocation factors may be related to the number of customers, energy usage, maximum demand for each customer class, or other

[3] Case No. EO-2025-0154 Non-Unanimous Settlement at 7-8

class-specific metrics. The average embedded cost approach treats new customers and existing customers the same, allocating costs to each in the same manner.[4]

Q. Do large loads present challenges to cost allocation that may require changes to this historical method?

A. Yes. The unprecedented size and scale of data center load creates new risks and mean that frameworks that have worked well in the past to achieve fair cost allocation outcomes will not necessarily work as well in the future. Given that SB 4 required the filing of new tariffs and established requirements regarding the impacts of large-load customers on rates for other classes, it appears that the legislature also shares this view.

Q. What are the risks to other customers from using the average embedded cost methodology to allocate costs to large loads?

A. Serving new loads that could significantly increase the capacity of the electric grid in less than a decade will require investments in incremental generation and transmission infrastructure at an extraordinary speed and scale. Such rapid, large-scale investment will increase prices for new generation, as costs move up the supply curve for new generation resources, raising the marginal price for supply to serve all load. This concept is well articulated in a study commissioned by the Virginia Joint Legislative Audit and Review Commission ("JLARC"), a government entity in Virginia that conducts program evaluation, policy analysis, and oversight of state agencies on behalf of the Virginia legislature.[5] Virginia, the largest data center market in the world, is grappling with the

[4] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. "Electric Cost Allocation for a New Era: A Manual" at 29. Montpelier, VT: Regulatory Assistance Project. Available at: https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.
[5] Virginia Joint Legislative Audit and Review Commission, Data Centers in Virginia Report. December 9, 2024 https://jlarc.virginia.gov/pdfs/reports/Rpt598-2.pdf ("JLARC Report").

complex policy challenges related to the impact of data centers on electricity prices and markets.

As shown in Figure RN-1, below, as load increases, the marginal cost to add additional load also increases as a result of the demand for new generation resources outstripping the available supply. This concept can be seen in the recent escalating costs of new gas-fired power plants. Due to significant demand for new generation, as well as inflation, recent prices for combined cycle natural gas generators have increased from between $1,116-$1,427 per kilowatt ("kW") to $2,000 or more per kW in just a few years.[6] Much of the price increase is driven by rising electricity demand to power new data centers, creating a backlog and significant waiting lists for new generation. The result of this phenomenon is that the marginal cost to serve this unprecedented new load will be significantly higher than the average cost of historical resources serving existing customers.

[6] The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S. at 4. Available at https://gridlab.org/portfolio-item/gas-tubine-cost-report/.

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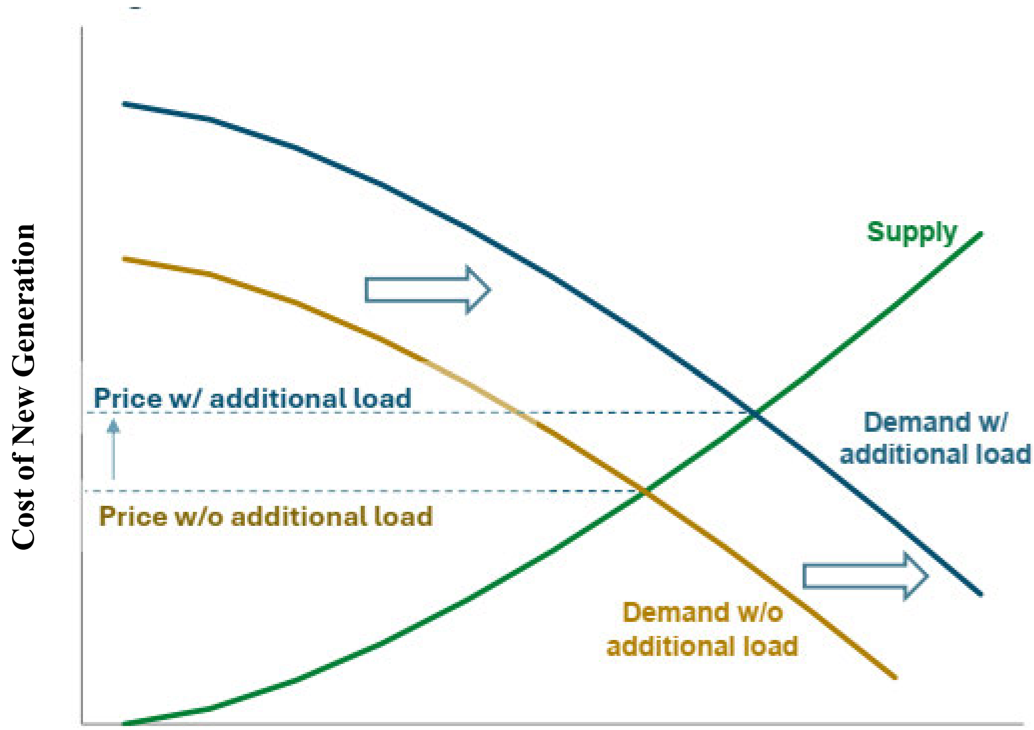
Figure RN-1[7]



Q. If the marginal cost of serving new generation exceeds the average system fixed costs, what will be the impact on existing customers' rates?

A. If the marginal cost to serve a new customer exceeds the system's average embedded cost, and that average is allocated to the new customer, there would be a shortfall between what the new customer pays and the costs they caused. The gap between costs caused and costs allocated would need to be paid for by existing customers, increasing their rates in the short term. Adding the new, more expensive assets to the system will raise the average costs, which are allocated to all customers, which will raise rates. This increase will happen even if new large loads are allocated their share of average embedded costs. In addition, as embedded costs are allocated to rate classes using allocators, a portion of the socialized

[7] JLARC Report at 80.

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embedded costs will also be allocated directly to existing customers in other rate classes under the embedded cost approach.

Q. Is there evidence that large loads are exerting upward pressure on generation costs, leading to rate increases?

A. The Independent Market Monitor for PJM released a report in June 2025, which found that data center load growth was directly responsible for the extremely high prices observed in the PJM Base Residual Action ("BRA") for capacity. In particular, the authors wrote "data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the tight supply demand conditions, the high prices observed in the BRA for 2025/2026 or the high prices expected for the 2026/2027 and subsequent capacity auctions."[8] PJM is ahead of many jurisdictions with seeing data center impacts because there are large hubs developing in Virginia, Pennsylvania, and Illinois. However, it is likely that the generation and transmission rate increases experienced within PJM will translate to other jurisdictions as data center development increases in other markets.

Q. What are the impacts of transmission upgrades necessary to serve data centers in SPP?

A. A recent report from the U.S. Department of Energy found that much of the planned transmission network upgrades in the nation, including $7.7 billion in SPP alone, are driven

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[8] The Independent Market Monitor for PJM, Analysis of the 2025/2026 RPM Base Residual Auction, Part G. June 3, 2025. Available at: https://www.monitoringanalytics.com/reports/reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf.

primarily by load growth from large loads.[9] In addition, the recent Show Cause Order from FERC found the SPP's current tariff is unjust, unreasonable, and lacks sufficient mechanisms to prevent data center-driven network transmission costs from shifting onto regular retail ratepayers.[10]

Q. Are there jurisdictions outside of PJM experiencing increasing generation and transmission costs because of rapid data center-driven demand growth?

A. Yes. In Georgia, Georgia Power increased its estimate of how much new capacity would be needed to serve its loads in 2030 from 400 MW in 2022 to 8,500 MW in 2024.[11] Driven by rapidly increasing demand from data centers, Georgia Power filed a request to the Georgia Public Service Commission ("GPSC") for approval to acquire 9,900 MW of resources at a cost of over $15 billion.[12]

Similarly in Wisconsin, Wisconsin Electric filed an application for approval of a Very Large Customer Tariff and Bespoke Resources Tariff aimed at addressing cost allocation for data centers. The company's investor presentations show it expects to spend $19.3 billion on electric generation over the next five years,[13] a $6 billion increase relative to the five-year plan submitted just a year prior.[14]

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[9] U.S. Department of Energy. National Transmission Needs Study, Draft for Consultation and Public Comment, July 2026 at vii. Available at https://www.energy.gov/documents/national-transmission-needs-study-draft-july-2026

[10] *Southwest Power Pool, Inc.*, 195 FERC ¶ 61,213 (2026)

[11] *2025 Data Center Fact Sheet,* Georgia Public Service Commission, https://psc.ga.gov/site/downloads/datacenterfactsheet.pdf.

[12] Georgia Power Company's Application for the Certification of the All-Source Capacity Power Purchase Agreements and Company-Owned Proposals, Docket No. 56298, https://psc.ga.gov/search/facts-document/?documentId=223493.

[13] WEC Energy Group Investor Update: December 2025, at 14. https://s22.q4cdn.com/994559668/files/doc_presentations/2025/Dec/05/12-2025-December-Final.pdf.

[14] WEC Energy Group Investor Update: December 2024, at 13. https://s22.q4cdn.com/994559668/files/doc_presentations/2024/Dec/06/12-2024-December-Final.pdf.

Q. How are states responding to the significant investments required to serve data center load with regard to cost allocation?

A. Many of the states with significant proposed data center development are moving away from their traditional cost allocation approaches to protect other ratepayers from cost increases and also reduce the risk of stranded assets. While this market is changing quickly, we are increasingly seeing commissions and utilities move to either directly allocate a portion, or all, of the incremental costs of new generation and transmission resources directly to new data center load or develop hybrid approaches, where either a portion of incremental resources is directly allocated to data centers or where data centers are required to pay more than their average embedded costs for generation and transmission resources. These revenues would be used to offset cost increases from data centers for those customers and represent a move away from the state's traditional cost-recovery methodology.

In Wisconsin, Wisconsin Electric proposed that generation and transmission costs be directly allocated to data centers to prevent cost shifting to other customers and reduce the risk of stranded assets.[15]

The Oregon legislature passed the Protecting Oregonians With Energy Responsibility, or POWER, Act in June 2025, requiring the Oregon Public Utility Commission ("OPUC") to ensure large customers, demanding 20 MWs or more of power, to sign contracts for at least 10 years and pay for all of the costs they cause and commit to pay for a minimum amount

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[15] Application of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs, Docket 6630-TE-113, Final Order (May 21, 2026), https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=591873.

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of energy and the costs of new transmission.[16] Portland Gas and Electric ("PGE") has introduced Schedule 96, approved by the PUC in May 2026 establishing a rate class for large load customers and including protections against cost shifting to other customers: large load customers must pay for 100% of dedicated distribution network upgrades; minimum generation and transmission demand charges are based on 90% of contracted capacity; minimum contract terms are set at 10 years and escalate based on demand, with the largest data centers needing to sign 30- year contracts; and termination fees include the net book value of distribution assets and the greater of remaining transmission and demand charges or three years of minimum transmission and demand charges.[17] The changes resulted in PGE filing a rate case that assigns a 30% increase to large load customers, and lowering residential rates.[18] Similarly, PacifiCorp has proposed a tariff that would create a new rate schedule for "New Large Energy Use Facilities." The proposal would require large load customers to pay the full cost of infrastructure upgrades needed to serve them.[19]

In Utah, the legislature passed SB 132, which creates a framework for "large-scale electric service" that includes a tariff for large, flexible loads. The law requires that incremental costs, including generation and transmission costs, are excluded from general rates in order

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[16] Relating to large energy use facilities; and declaring an emergency., House Bill 3546 (Oregon Legislative Assembly – 2025 Regular Session). https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled.
[17] Schedule 96 Adopted with Modifications; Revisions to Schedules 89 and 90 Ordered; Revisions to Rules C and I Ordered; First Partial Stipulation Adopted, Oregon Public Utility Commission, Order No. 26-154, Docket No. UM 2377 (May 7, 2026), https://apps.puc.state.or.us/orders/2026ords/26-154.pdf.
[18] See https://www.kgw.com/article/money/business/pge-raise-rates-data-center-residential-commercial-industrial-power-electric/283-420918fa-4f2f-4f4d-9723-e08ae1245581
[19] Re: Advice 25-015—Schedule 401—Service to New Large Energy Use Facilities, Docket UE 463 (October 2, 2025), https://edocs.puc.state.or.us/efdocs/UAA/ue463uaa342299028.pdf.

to minimize the potential for cross-subsidization between existing customers and new large load customers.[20]

Arizona Public Service ("APS") recently proposed an updated cost allocation methodology in its ongoing rate case. Their approach allocates incremental generation costs to each customer class based on its contribution to the growth in peak demand.[21] APS proposes to differentiate new generation resources between generation needed to replace retiring resources and generation needed to serve new load growth. To perform this categorization, APS will compute the effective load carrying capacity ("ELCC") of retiring assets and subtract that value from the ELCC of any new generation resources. The remaining portion will be treated as serving new load growth, and the cost of all new generation resources will be divided accordingly. APS will continue to allocate new generation costs associated with retiring assets using their traditional embedded cost methods, while generation costs associated with serving new load will be allocated according to the proportion of test year load growth in individual customer classes.[22] In this way, existing customers may be insulated from any cost-shifting due to generation costs caused by growth in large load customers.

In June 2026, FirstEnergy Service Company submitted comments to FERC's Advance Notice of Proposed Rulemaking ("ANOPR") on the interconnection of large loads.[23]

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[20] S.B. 132, Electric Utility Amendments, 2025 General Session State of Utah, https://le.utah.gov/Session/2025/bills/enrolled/SB0132.pdf.
[21] Jamie Moe, Direct Testimony, ACC Docket No. E-01345A-25-0105 at 14:21-27.
[22] Moe Direct at 17:13-23
[23] *Interconnection of Large Loads to the Interstate Transmission System*, Notice Inviting Comments, Docket No. RM26-4-000 (Oct. 27, 2025) (the Commission issued the ANOPR following a directive from the Secretary of Energy ("Secretary") pursuant to section 203 of the Department of Energy Organization Act); see also the full text of the proposed ANOPR, *Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000 (Oct. 23, 2025).

FirstEnergy's proposal includes two rate components: current zonal transmission rates to pay for the existing transmission system, and an expansion rate that pays for the network upgrades needed to interconnect new large loads. A data center's obligation for the expansion rate would be reassessed annually as new customers interconnect to the same transmission facilities, ensuring the expansion costs are allocated fairly among the class of customers causing the expansion.[24]

In April 2025, the Pennsylvania PUC held an *En Banc* Hearing regarding the interconnection of and tariffs for, large load customers. Subsequently, the Pennsylvania PUC developed a model tariff that was based on the comments from more than 50 stakeholders. In its final decision, the Pennsylvania PUC found that the cost of network improvements that would not have been needed "but for" the interconnection of a large load customer should be allocated to that customer. In such cases, utilities should assess contributions in aid of construction ("CIAC") to recover all distribution and transmission costs needed to connect the new customer.[25]

Public Service Company of Colorado (Public Service), in April 2026, proposed a new large load tariff (Schedule TL) that was designed to ensure large load customers pay *at least* the incremental costs incurred to serve them, with the goal of protecting existing customers from cost shifting. To properly enact this tariff, Public Service will calculate the incremental cost of generation and transmission assets required to serve new large load

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[24] Supplemental Comments of FirstEnergy Service Company, *Interconnection of Large Loads to the Interstate Transmission System,* Docket No. RM26-4-000 (Jun. 5, 2026), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260605-5169&optimized=false&sid=0a8a51cb-1d1c-46c6-9dc9-868f7f952218.

[25] Interconnection and Tariffs for Large Load Customers, Docket Number M-2025-3054271, Final Order (May 2026), https://www.puc.pa.gov/pcdocs/1929842.pdf.

customers. Then, in a ratemaking proceeding, the company will assess the costs that would be allocated to large load customers under the standard cost allocation framework and allocate to the large load customer class the greater of the incremental or embedded costs. This example is a clear demonstration that it is not obvious whether incremental or embedded costs are greater for large loads. In addition, large load customers will be required to pay standard rates for other rate components.[26]

Finally, in its last rate case, Florida Power & Light Company ("FPL") entered into a contested, non-unanimous settlement agreement with a select number of non-residential customers that introduced a new rate for data centers. The rate includes an Incremental Generation Charge ("IGC") which recovers incremental generation costs incurred to serve the large load customer.[27] Notably, FPL introduced this new rate class in anticipation of new data center customers, but does not have a high concentration of data centers currently.[28]

Across all these states, there is a recognition that data center demand growth is unprecedented, poses new risks, and can expose customers to increased costs in the short run and stranded assets and cost-shifting over the medium-to-long term. Because of this

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[26] *In the Matter of Advice No. 2018 – Electric Filed by Public Service Company of Colardo to Revise Colorado P.U.C. No. 8 – Electric Tariff to Address Large Loads and Add Transmission Large (Schedule TL) and Clean Transition Tariff (Schedule CTT) and Implement Changes to the Transmission Line Extension Policy,* Proceeding No. 26AL-0137E, Direct Testimony of Jeffrey R. Knighten, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_832352.

[27] Order No. PSC-2026-0022-S-EI in Docket No. 20250011-EI, issued January 22, 2026. https://www.floridapsc.com/pscfiles/library/filings/2026/00561-2026/00561-2026.pdf. It is my understanding that this order is not final and is currently subject to a motion for reconsideration filed on February 6, 2026 (Doc. No. 00986-2026). Additionally, I am not testifying to reasonableness of the method used to identify incremental generation charges. Any method proposed by DEF should be reviewed and analyzed based on the circumstances at that time.

[28] "Q&A with FPL President on expected data center growth and the company's new customer protections." *FPL Newsroom* (Jan. 2026). https://newsroom.fpl.com/Q-A-with-FPL-President-on-expected-data-center-growth-and-the-companys-new-customer-protections.

risk, each of these states has introduced new laws or proposed legislation, regulatory frameworks, or cost allocation approaches aimed at addressing the incremental cost increases that data centers threaten to impose on other customers.

Q. What can this Commission learn from recent experiences in other jurisdictions?

A. Across both deregulated markets like PJM and vertically integrated markets like Xcel Energy and Wisconsin Energy, areas with significant demand growth from data centers and other large load customers—whether existing or forecast—have experienced increased costs and the increased risk of cost shifting and stranded assets. These jurisdictions are altering their ratemaking practices to address incremental costs through different forms of cost allocation, including direct allocation. While the specific rates for Schedule LLPS are not at issue in this case, it is still worth considering what types of adjustments to utility cost allocation and functionalization methods may be required to meet the requirements of SB 4.

Q. Are there other emerging issues regarding new large loads that you'd like to address?

A. Yes. As I will discuss in more detail below, the interconnection of new large loads that can significantly impact EMM's peak load presents a unique challenge for matching costs and revenues in a rate case. This challenge occurs because the costs to serve these new loads are incurred before the expected revenues materialize. This mismatch can lead to large load costs being borne by other customer classes in the near term until the expected revenues are included in a COSS model.

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B. LLPS Tariff Provisions Regarding Cost Allocation in this Rate Case

Q. Are there any large load customers under Schedule LLPS in the Company's test year?

A. No. There were no customers who met the eligibility criteria for Schedule LLPS in the Company's test year.[29] However, since the test year, a new Schedule LLPS customer has begun taking service from EMM.

Q. Can you describe the new customer taking service under Schedule LLPS?

A. ***____
____ ***[30]

Q. What will be the impact of this customer on EMM's peak load once it is fully ramped to its contracted capacity?

A. **____
____
_______________________ **

Q. Given the transformative nature of this one customer on the Company's peak demand and energy requirements, what steps does the Company claim to have taken to address future revenues that do not appear in the test year?

A. The Company states that it has taken a "proactive" approach to include revenue from known large load activity into its revenue projection in this rate case. This approach

[29] Direct Testimony of Kevin Gunn at 16:12-13
[30] Discovery Response 0226 Conf Attachment

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includes adding expected revenues during the true-up period, plus an additional $9.1 million in anticipated LLPS-related revenue growth.[31]

Q. What is the total impact of this "proactive" adjustment made by EMM to its COSS?

A. The total impact of this adjustment adds ***__________*** in revenues to the Company's COSS model. The ***________ *** was calculated by first estimating ***____ __________***. This estimation equals ***__________ ***. The Company then added ***__________*** to this value, representing the expected revenue from the same customer for July and August 2026.[32]

Q. Does this adjustment alleviate your concerns about whether the Schedule LLPS customer is affecting the just and reasonable rates of other customer classes?

A. No, it does not. The Company has taken steps to account for revenue growth from Schedule LLPS not included in the test year. However, the Company's adjustment does not go far enough to address cost shifting to other customer classes. The addition of a transformative load customer after the test year and true-up period has created a mismatch between the revenues in the COSS and costs. This mismatch is driven by the inclusion of costs to serve this Schedule LLPS customer and potential others in the Company's Revenue Requirement in this proceeding. However, the potentially enormous revenues from any Schedule LLPS customers are not fully accounted for.

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[31] Direct Testimony of Kevin Gunn at 16:16-21
[32] Confidential Proposed Class Allocator Workpaper and Q0293 Confidential LLPS Forecast

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Q. What incremental costs are included in the Company's Revenue Requirement in this proceeding regarding the interconnection of new large loads?

A. In this proceeding, the Company includes $86.4 million in Construction Work in Progress ("CWIP") related to the construction of new natural gas generators. While the Company claims that these new generators are being built to serve all of its customers, the load growth it is experiencing is primarily driven by new large customers. The Company states that none of these CWIP costs have been assigned to Schedule LLPS in the rate proceeding.[33]

Q. Does EMM's own data contradict its assertion that large load growth is not driving the need for new generation?

A. Its 2026 Annual Update to its Integrated Resource Plan shows that large load additions are the primary driver of its energy and peak demand growth over the next five years, with native load and demand relatively stable.[34] In addition, the Company has stated to investors that large customers will drive significant load growth through 2030 and beyond.[35] Thus, large loads that can increase the Company's peak demand by 40% are the driver of the need for additional generation plant.

[33] Response to MECG 3.3
[34] Evergy Missouri Metro 2026 Annual Update, Integrated Resource Plan, May 26 at 25-26. Available at https://efis.psc.mo.gov/Document/Display/876123
[35] Evergy First Quarter 2026 Earnings Call, May 7, 2026 at 14. Available at https://investors.evergy.com/static-files/96421673-737d-4a5d-9206-f53b1a3e3b22

Q. Has the Company conducted any analysis to support its assertion that large-load customers are not driving the need for new generation?

A. No, it has not. When asked in discovery, the Company stated it has not produced any analysis to identify which projects would not have occurred "but for" new Schedule LLPS customers.[36]

Q. Why are none of the CWIP costs allocated to Schedule LLPS customers?

A. The Company states that the CWIP generation costs in the COSS are allocated via the Average and Excess ("A&E") method using a four critical peak ("4-CP") component, i.e. an A&E 4-CP, as the Company proposes for all production costs.[37] As there was no Schedule LLPS demand or energy consumption in the test year, this allocation method does not allocate any costs to this rate schedule.[38]

Q. What is the impact of not allocating any CWIP costs to Schedule LLPS?

A. The impact is that every customer class except Schedule LLPS will carry the burden of paying these costs, which raises rates above what they would be without Schedules LLPS customers.

Q. Are your concerns regarding cost allocation related to Schedule LLPS limited to CWIP costs?

A. No, they are not. My concerns extend to all new and recently constructed production and transmission costs involved in this proceeding. Given that Schedule LLPS is not included in the A&E 4-CP billing determinants, none of these costs are specifically allocated to this

[36] Response to MECG 3.4
[37] Response to MECG 3.5
[38] Response to MECG 3.7

or other large-load customer classes. If any of the expected load from known Schedule LLPS customers was included in the calculation of the A&E 4-CP allocators, then significant additional costs for production and transmission costs would be allocated to large customers and away from smaller customers, such as the residential customer class.

Q. Can you show how new large-load customers will affect cost allocation going forward?

A. As a hypothetical, I took the projected capacity and energy for ***__________ ***, provided by EMM for July 2030, and added it to the billing determinants used to calculate the A&E 4-CP allocators in this case, holding load and capacity for all other rate classes constant. I chose July 2030, as this will likely be the end of the true-up period in the Company's next rate case. As shown in Table RN-1, adding the ***__________ *** projected load allocates ***__________ *** to Schedule LLPS and reduces the allocation to all other customer classes. This is especially pronounced for the Residential Time of Use ("TOU") customer class, whose allocation decreases by 7%.

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[redacted]

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Q. What are the impacts of not including any load from Schedule LLPS in the COSS cost allocators?

A. One Schedule LLPS customer has already begun to take service from the Company, and its load ramp over the next four years will dramatically change the Company's load profile and significantly increase its revenues. By not including any expected load from this one customer, the Company is significantly overallocating costs to other rate classes that would more appropriately be allocated to Schedule LLPS. Thus, the residential customer class rates will be significantly higher than they would have been if this load was included within the COSS as a known and measurable change. All things equal, the significant revenues

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projected from Schedule LLPS will accrue to the Company as a windfall profit unless adjustments are made with the COSS revenue allocation methodology to account for this forthcoming new load.

Q. Are you able to quantify the magnitude of this windfall for EMM?

A. ***____

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Q. What are the drivers of the windfall for EMM from the addition of new large load customers?

A. As I have already discussed, this windfall is driven by the mismatch between the costs incurred and included in the Company's revenue requirement in this rate case to serve new large-load customers and the revenues expected from Schedule LLPS customers in the future. While the Company has included a small adjustment to revenues to address the mismatch, it fails to account for the vast majority of expected revenues. The end result will harm all other ratepayers and unreasonably enrich EMM over the coming years.

Q. Will this issue be resolved in the Company's next rate case when load from new large customers will be better accounted for in the Company's COSS model?

A. Over the long term, assuming the need to build additional resources slows and the new customer load matches projections, it may be addressed in future rate cases. However,

[39] Calculated by summing the projected revenues from Project Shale in the 0293_Confidential_LLPS Forecast for 9/1/26-12/1/30 and subtracting the annual revenues for the adjustment made by the Company in the rate proceeding

______________________________ , so this issue will persist related to this one customer for at least the next two rate cases, and perhaps more. In addition, if the Company adds additional Schedule LLPS customers that necessitate building incremental generation and transmission resources, the issues I highlight will continue beyond that timeframe.

Q. Are you proposing remedies to address this issue in your testimony?

A. Yes. As I've discussed above, the Company's small revenue adjustment to address expected revenues under Schedule LLPS represents a good first step. However, given that revenues from Schedule LLPS will increase dramatically over the next four years when the rates for this proceeding are in effect, this approach will shift significant costs to other rate classes and provide a huge windfall profit to the utility. To address this unreasonable rate increase for other rate classes as a result of Schedule LLPS customer I present two proposed solutions.

Q. What is your primary recommendation to address Schedule LLPS revenues?

A. My primary recommendation would be to increase the adjustment made by the Company regarding Schedule LLPS revenues from ***______________________________ ____***. I arrived at that number by taking expected revenue from ***____________ ______________ ***, the last year that rates from this case may still be in effect. This adjustment will better match the expected revenues from ***__________*** and represents a reasonable known and measurable change to the Company's COSS model.

Q. What is your secondary recommendation regarding treatment of future Schedule LLPS revenues?

A. If the Commission would prefer not to make such a large pro forma adjustment to the Company's revenues, it could also establish a mechanism similar to the Earnings Review Surveillance (ERS) in Case No. ET-2025-0184. Under such a mechanism, the Company would annually calculate revenues from Schedule LLPS customers. Any revenues that exceed the pro-forma adjustment of ***__________ *** included in the Company's COSS model would be refunded to all other rate classes in the following year.

Q. Under this proposal, if revenues from Schedule LLPS were less than ***__________ _______ *, would the Company receive additional revenues?**

A. No. Additional revenues would not flow to the Company if it undercollects from Schedule LLPS. This is highly unlikely given the terms of Schedule LLPS and the expected ramp rate of Schedule LLPS customers.

Q. Did the Commission consider a similar mechanism in Case No. EO-2025-0154?

A. Yes, it did. In that case, Staff proposed a mechanism to address revenues from Schedule LLPS customers occurring between rate cases. As there are no Schedule LLPS customers, the Commission deferred a decision on the merits of such a mechanism to a future rate case when they would be known and measurable.[40] As I stated above, at this time those revenues are known and measurable, and it is appropriate to address them to the benefit of EMM's customers.

[40] EO-2025-0154 Report at Order at 44

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Q. Where would this annual true-up occur?

A. The annual true-up could occur as a separate filing with the Commission or be combined with an existing adjuster filing for administrative efficiency. The Company would calculate the revenues to be returned to other customer classes by comparing total revenues received from Schedule LLPS customers with the amount included in this proceeding. It would then allocate that refund to specific rate classes using the retail revenue allocator approved in this proceeding, similar to how it is allocating the LLPS credit in this proceeding.

Q. Would such a true-up undermine the LLPS Credit approved in Case No. EO-2025-0154?

A. No. This crediting mechanism would be in effect between rate cases, while the LLPS Credit approved in Case No. EO-2025-0154 only applies within the COSS model in a rate case. Thus, it would not undermine that previously approved credit.

III. EMM's Cost of Service Model

A. Background to COSS

Q. What is a COSS and why is it important to the rate case?

A. A COSS refers to the process by which the utility divides its revenue requirement into cost categories and assigns, or allocates, these categories of costs to different customer classes. The costs allocated to a customer class are used to inform how much revenue is collected from that class, and, therefore, how high the rates for that class will be set. The COSS is important to this case because many aspects of the power system are changing as different technologies are integrated and utilities are challenged by the need to connect unique and

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unprecedented loads. These changes impact how costs are caused and need to be reflected in cost of service methodologies.

Q. Is there a single standard method by which every utility conducts a COSS?

A. No. While the core steps of a COSS, which I'll explain in a moment, are generally consistent across utilities, the methodologies used can depart substantially. Additionally, the decisions about which methodologies are used for a COSS significantly impact results and need to be evaluated in-depth to ensure the methodologies continue to reflect cost causation as system dynamics change.

Because COSS methods and the corresponding results can vary significantly based on arguable assumptions and preferences, the Commission should exercise caution when using a COSS to inform revenue allocation and rates. Every cost analyst makes numerous subjective determinations that will dramatically impact the results of the study.

In my testimony, I suggest reasonable alternative approaches to the methods that the Company has chosen to use and demonstrate their impact on the results. Ultimately, the COSS I recommend is better supported by economic theory and power system engineering. While I acknowledge that no COSS is perfect, I explain the reasons that certain approaches are more reasonable and should therefore be considered by the Commission when determining revenue allocation and rate design.

Q. What is the purpose of a COSS?

A. The purpose of a COSS is to categorize costs into bundled cost categories and to decipher, with as much detail and accuracy as possible, which customer class caused the utility's various embedded costs to inform class revenue allocation and rate design.

Q. How is a traditional COSS performed?

A. A COSS has three steps:

- Functionalize costs into various categories.
- Classify costs related to energy/commodity, demand/capacity, or customers.
- Allocate costs to the various customer classes using allocators related to energy, demand, or customer characteristics.

The principles of cost causation and beneficiary pays are used throughout the COSS to determine the most appropriate functionalization, classification, and allocation of costs. "Cost causation" dictates that the user(s) who incurred, or caused, a cost must pay for it. Conversely, "beneficiary pays" dictates that all of those who benefit from an investment must pay for its costs – in other words, "costs follow benefits." Incorporating the beneficiary pays principle at the retail level is a more modern concept but is reflected in some traditional cost classification and allocation approaches.

Q. How are costs functionalized?

A. Functionalization is the process of grouping utility cost by function. For example, generation, transmission and distribution are different functional cost categories. Public utilities are required to maintain records in accordance with the Uniform System of Accounts as designated by the Federal Energy Regulatory Commission (FERC). These accounts divide costs by various cost functions, such as generation, transmission, and distribution. The purpose of functionalizing costs is to aid in determining which customers are jointly or solely responsible for various costs. Many utilities also sub-functionalize costs, which often aligns with different voltage levels. For example, distribution costs can

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be sub-functionalized into primary and secondary voltages. The purpose of sub-functionalization is to reflect cost causation or beneficiaries more granularly.

Q. How are costs then classified?

A. Cost causation is used to classify whether each cost is an energy-, demand-, or customer-related cost. Energy costs relate to a customer class's energy usage, measured in kilowatt-hours ("kWh"). Capacity costs relate to a customer class's contribution to peak demand within the system, measured in kWs. Finally, customer costs are those required to provide service to customers, regardless of whether the customers consume electricity. Specifically, the National Association of Regulatory Utility Consumers Electric Manual (NARUC Electric Manual) defines customer costs as "costs that are directly related to the number of customers served."[41] In other words, the utility incurs customer costs based on the number of customers on its system, rather than based on the amount of energy they consume or when they consume it.

Q. How are costs allocated once they have been classified?

A. Costs are allocated to customer classes based on each class's contribution to each classified cost. As for customer related costs, if a utility's costs are caused equally by each customer on the system, regardless of energy and demand requirements, these costs would be allocated based on the number of customers. As for demand-related costs, customer classes can be allocated costs based on their contribution to system peaks or non-coincident peak demands. As for energy related costs, the utility costs are allocated based on kWh consumption levels or a similar energy related characteristic.

[41] NARUC, *Electric Utility Cost Allocation Manual* (1992), 20.

Q. You indicated earlier that cost of service studies are fundamentally based on philosophical decisions of a utility or analyst. What do you mean?

A. Each decision of a cost of service study has an implication, sometimes quite profound, on how costs are divided amongst customers – i.e. who will bear the costs of the utility – and the cost signals sent to those customers, if any. Decisions about how costs are functionalized, classified, and allocated are inherently subjective, and can be tuned to achieve different objectives.

B. Cost of Service Studies in a Changing Power System

Q. Do you have any observations about how COSS methods need to evolve within a modern power system?

A. Yes. Across the nation, renewable energy is the fastest-growing energy resource, driven by its increasingly competitive costs, relatively short construction timelines, expanding markets for clean energy, and state renewable energy standards that promote its development. At the same time, more energy storage is also being added to the grid in order to provide peaking capacity, but also to help smooth out the natural variation in renewable resources like wind and solar. Compared to traditional gas peaking resources, battery storage can dispatch much more frequently and thus serve as an important source of system flexibility not just to meet system peak demand, but throughout the year.[42] This changing power system structure has made the flexibility of both supply and demand side resources increasingly important. As the power system adds more renewables, power system

[42] Traditional gas peaker plants are often cheaper to build in terms of capital cost per MW of nameplate generating capacity, but are more expensive to operate because they are typically less efficient. As a result, they are only dispatched when required to meet system load above a certain level.

planning will be far less about "building to the peak" and much more about optimizing a diverse array of clean energy resources, including demand-side resources.

Q. How do these electric system changes impact cost causation and rate design?

A. Cost causation principles will need to evolve to reflect this broader and more nuanced electric system paradigm. As the characteristics of generators have changed over time, the nature of cost causation has necessarily evolved as well. Historically, applying cost causation to fixed generation costs has been primarily a function of variation in demand, typically measured only during a select few hours in a year. The traditional cost causation logic has been that customers with higher peak demand incurred greater costs for generation, transmission, and distribution infrastructure. This perspective excludes consideration of energy use as a factor in cost causation and cost allocation for fixed generation costs. In a modernized electric system, however, a customer's impact on peak demand may not be the predominant factor driving cost. Indeed, factors like a customer's consumption of fuel-intensive resources or impact on net peaks (periods in which high demand coincides with low renewable availability) may be far more indicative of a customer's cost causation. This change emphasizes the importance of temporal analysis of when energy is generated and consumed, to align cost causation with temporal energy costs. In other words, costs are increasingly caused by energy use throughout the day and season, rather than a limited number of high demand hours throughout the year. Reflecting the evolution of cost causation from a focus on demand allocators that focus on a few peaks, towards energy (or demand) allocators that more broadly reflect costs caused by load profiles is needed within current COSS models. This shift in usage has a particular impact on large load customers, who traditionally have high load factors (i.e. usage around the clock) and less load flexibility.

Q. How do large customers with high load factors impact the electric system?

A. Historically, when cost causation was principally focused on peak-demand, high-load factor customers were seen as cost-effective loads to serve because they aligned more closely with the economics of base load power plant operations. A high-load factor customer typically uses a steady, consistent and high level of energy throughout the day and year. Due to that characteristic, high-load factor customers improved the cost-effectiveness of a system operating large baseload (e.g. nuclear and coal) facilities, which tended to have high fixed costs and relatively low variable costs, and have less flexible operations. However, in the evolving power system, marginal additions to the grid are predominantly intermittent renewable resources. As a result, the cost causation paradigm has shifted such that high load factors and demand inflexibility increase costs. For example, during hours with low renewable generation, inflexible loads require higher cost dispatchable resources or new battery storage to serve their demand. As the electric grid integrates more renewable energy, amplifying the temporal value of load flexibility, the cost of service must reflect these increasing costs for high load factor customers. In other words, flexible loads are increasingly lower cost and more cost effective for the system, while inflexible, flat loads incur higher costs to the system.

Q. What implications does this change in cost causation have on traditional methods of cost allocation?

A. When costs were primarily driven by peak load, cost allocation methods based on class peak demand were appropriate. Several methods in widespread use compare customer class load through various measures of class coincident and non-coincident peaks to determine the equitable division of distribution, transmission, and production costs. However, as temporal differences between customer class loads have become more impactful on cost causation, it has become more appropriate to use allocation methods that incorporate the time at which classes use power.

Q. What are the implications of using a cost allocation method that does not accurately reflect class cost causation?

A. If class cost allocation does not reflect actual cost causation, it can result in inter-class subsidies. An inter-class subsidy arises when one customer class is allocated a level of cost recovery lower than its cost of service, at the expense of one or more other customer classes. Ultimately, the choice of which methodologies are used is subjective, which means that intra-class subsidies are a choice, not just the result of an objective model. It is imperative to use a methodology that reflects robust economic theory in developing future rates.

C. EMM's use of the Average and Excess Method to allocate production and transmission costs

Q. How does EMM propose to allocate production and transmission costs in this case?

A. The Company proposes to allocate production and transmission costs using the A&E 4-CP method.[43]

Q. Please summarize this method.

A. The A&E method incorporates class average annual load and class peak above-average load into a single allocator. The average load component consists of each class's annual load divided by the number of hours in the test-year. The excess component is based on the difference between class average load and each class's 4-CP load, or average class load during the Company's four highest system coincident peak load hours of the test-year. These two allocators are then scaled according to the Company's system load factor, or the ratio of average total system load to the single system coincident peak, and combined; the Company multiplies the average component by the system load factor, and multiplies the excess component by one minus the load factor, then adds the two scaled components together for the final set of allocators.

Q. What does Missouri statute say about production cost allocation?

A. Missouri statute states that the Commission "shall only consider class cost of service study results" that use either the A&E method or "one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual…" to allocate production costs from nuclear and fossil-fueled generating units.[44]

[43] Direct Testimony of Graham Jaynes at 37:13-20
[44] Mo. Rev. Stat. § 393.1620 (2021)

Q. Does the A&E method result in an equitable allocation of production and transmission costs?

A. No. The A&E method is an outdated measure of production cost-causation that places too much emphasis on peak demand. As I discussed in subsection III.B of my testimony above, this over-emphasis on contributions to peak demand can lead to class-level cross-subsidies.

Q. What alternative allocation method do you recommend to more accurately and equitably allocate production and transmission costs?

A. There are several allocation approaches presented in industry literature that would more specifically and accurately allocate the Company's production and transmission demand-related costs to align with its planning needs and data. However, because of the increasing importance of the timing of energy use, a temporal method of allocation is preferable, such as the Probability of Dispatch ("POD") method.[45]

Q. In what ways does the POD method more accurately allocate production and transmission costs?

A. The POD method evaluates the costs that each hour of load from each customer class places on the utility's production portfolio. Evaluating the full hourly (8,760) load profiles and their subsequent cost impact on EMM's production costs is especially important as more renewables and storage are coming onto the system. As renewable and storage resources increase, the timing of usage by a customer class becomes increasingly important. For example, if a customer class's load profile largely follows a solar generation profile, it would be extremely cost-effective because fewer storage and other dispatchable resources

[45] Lazar et al. at 118.

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are needed to serve the load. On the other hand, customer classes with high load factors that operate similarly around the clock and year become extremely expensive to serve because they will require more storage and dispatchable resources.

Q. According to industry literature, when is the POD method appropriate for allocation of production demand costs?

A. The POD method has broad applicability as it looks at generation and usage across all hours of the year and considers the amount of generation capacity that is available – not just installed – and how a customer class uses energy in relation to real system dispatch characteristics.[46]

Q. How is the POD allocator calculated?

A. The POD method involves building a utility's load curve and matching the cost of the units that run during each hour to the energy use of each customer class in each hour.[47] The historical variation in the timing of class loads demonstrates how production costs differ for each customer class. The POD method captures this difference by assigning production costs by hour throughout the year. Figure RN-2 shows the variation in net generation by generation type throughout the average day for the Company's test year, and Figure RN-3 shows the variation in average hourly load by class.

[46] *Id.* at 130-132
[47] National Association of Regulatory Utility Commissioners, "Electric Utility Cost Allocation Manual", January, 1992 at 62. Available at https://www.pubmanitoba.ca/pdf/cos_review/exhibits/mipug-28.pdf.

Figure RN-2. Average Hourly Net Generation by Type[48]

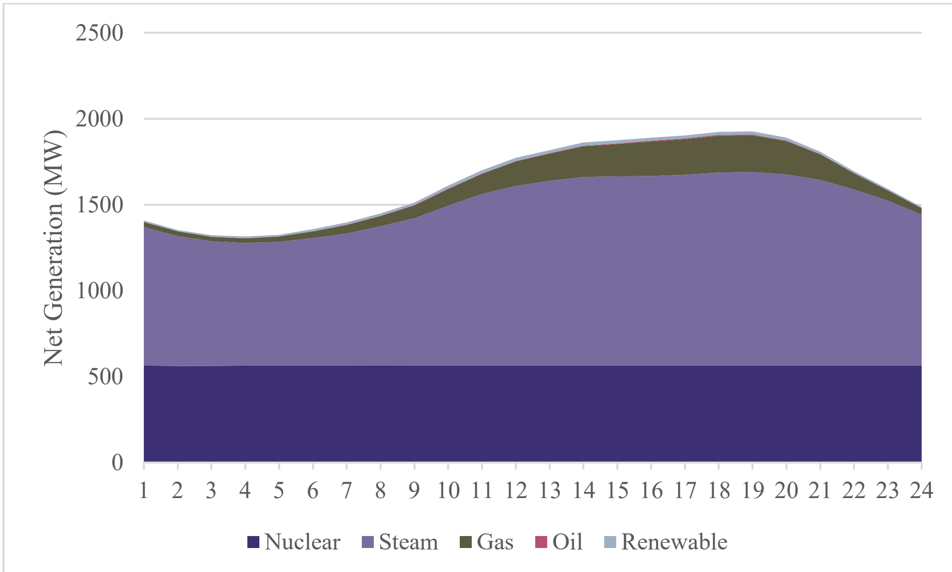
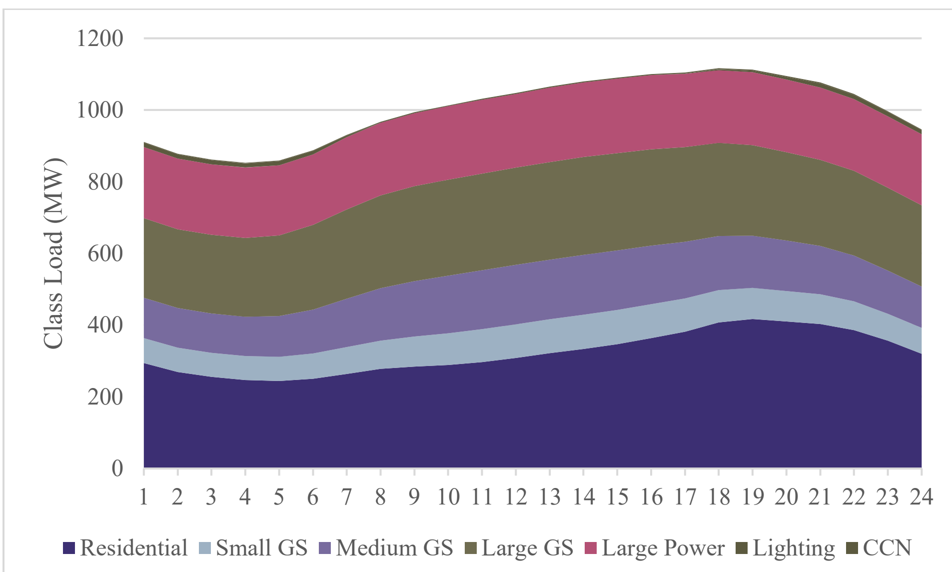


Figure RN-3. Average Hourly Load by Class[49]



[48] EMM Electric Generation Reporting Requirements (BEGR) filings for months July 2024 through June 2025. Available at https://efis.psc.mo.gov/NonCase.
[49] EMM Witness Bass Workpaper “AMI_LoadData_MO.xlsx”.

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The first step of the POD method is calculating the annual revenue requirement for each generating plant in the utility's fleet, which consists of the annual O&M, depreciation, and other fuel expenses associated with that plant plus the return on the plant's net plant in service value. Then each plant's annual revenue requirement is assigned to each hour of the year according to the proportion of that plant's annual net generation occurring during that hour. In this way, the method assigns each hour of the year a total production revenue requirement equal to the sum of each generating plant's hourly revenue requirement.

The second component of the POD method consists of each class's hourly load for the test year. The method distributes the hourly revenue requirements from the first step to each class according to its proportional hourly load during that hour. In this way, individual classes' contributions to the hourly load are matched with the actual hourly cost the utility incurs in meeting that load.

Q. Is the POD method a new concept in the cost allocation literature?

A. No, it is not. The NARUC Manual, which was published in 1992, identified the POD as one of the time-differentiated cost of service methods available to allocation production plant costs based on usage during baseload, peak, and other hours.[50] Thus, it meets the requirements of Mo. Rev. Stat. § 393.1620 (2021).

Q. Is there a reason the POD method has not been widely used historically?

A. While the POD method itself has been considered for decades, it was challenging historically to collect hourly energy usage and generation data. However, with the move towards Advanced Metering Infrastructure and improvements in computer processing it is

[50] National Association of Regulated Utility Commissioners, *supra* note 47.

no longer challenging to collect, compile, and analyze the data needed to utilize the POD method. Thus, while the POD method has been relatively rare historically, more utilities have been using or considering it for allocation of production costs in recent years.

Q. Is the POD method used by other utilities?

A. Yes. Other utilities have used a method similar to the POD method for allocating production and transmission costs including Mid-American in Illinois, Iowa, and South Dakota, and Public Service Company of Colorado in Colorado, with Colorado only moving to this method in the last few years.[51]

Q. Did you calculate an alternative POD allocation?

A. Yes. The production allocation results from the POD analysis are significantly different from the Company's A&E allocators. Table RN-2 below compares my results with the Company's production allocation.

[51] See CO PUC Proceeding No. 23AL-0243E Klingeman Direct. See Iowa Department of Commerce Docket No. RPU-2013-0004, Order Approving Settlement, With Modifications, and Requiring Additional Information, March 17, 2014. Mid American uses the hourly costing method, which also relies on hourly system data. The hourly costing method assigns an hourly production cost consisting of the adjusted local LMP and the hourly average $/MW price of the non-fuel production revenue requirement.

Table RN-2. POD and A&E Allocation Comparison

	A&E Allocators	POD Allocators	Difference
Residential	46.3%	32.9%	-13.4%
SGS	8.3%	8.2%	-0.1%
MGS	13.5%	14.0%	0.4%
LGS	18.6%	24.5%	5.9%
LPS	12.9%	19.7%	6.8%
Lighting	0.3%	0.5%	0.2%
CCN	0.1%	0.2%	0.2%
LLPS	0.0%	0.0%	0.0%
Total	**100.0%**	**100.0%**	

As these results show, the Company's continued use of the A&E method for production cost allocation assigns significantly more cost responsibility to the residential class than a time-variant method would suggest is appropriate, while assigning too little cost responsibility to the Large GS and LPS classes.

Q. Please describe the process of performing the POD analysis.

A. The POD analysis, as applied to EMM, is performed in the following steps:

1. Gather additional information, outside of the provided COSS, on EMM's hourly load and generation needed for the POD model. I obtained the hourly load profile for each customer class in the test year from EMM Witness Jayne's workpapers provided through discovery.[52] I also obtained hourly generation information for each generating plant in the test year, as well as production-related expenses and rate base asset values. Hourly generation data was collected from the Company's

[52] EMM Witness Bass Workpaper "AMI_LoadData_MO.xlsx"

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monthly 3.190 reports to the MPSC, and production cost information was collected from the Company's annual FERC Form 1 filing for 2025.

2. Determine the annual revenue requirement for EMM's generation fleet by adding the operation, maintenance, depreciation, and property tax expenses for each generator, and then adding the Company's allowed return on the net book value of those generators.

3. Determine the percentage of each generator's annual production that was produced in each hour of the year by dividing its hourly generation by its annual total.

4. Multiply the hourly generation percentages of each generator by their respective revenue requirement and then add each generator's hourly costs together to determine the total generation cost for each hour.

5. Allocate the costs of system generation, in each hour, to each rate class by their proportional load in that hour.

6. The costs allocated in each hour to each rate class are summed to derive a total allocation, or the relative fraction of total allocation, for each rate class.

Q. Should the POD allocation be used for transmission costs as well?

A. Yes. Transmission lines are built to optimize power flows and reliability across all seasons and hours of the year. The POD reasonably allocates the costs of transmission in addition to production costs.

Q. What is the policy justification for using the POD method?

A. POD more accurately reflects the costs caused by different rate classes for production demand costs by assessing the costs of generation over the entire test year thereby better matching customer benefits and cost causation with cost allocation.

Q. Do you have any other comments regarding the Company's production allocation methods?

A. Yes. In the course of preparing the POD analysis, I compared the energy allocators contained in the Company's COSS to the annual energy allocators that would result from the test-year hourly class loads in the Company's workpapers. After adjusting the metered hourly load totals for losses, using the loss factors provided in Witness Jayne's external allocators workpaper, the two sets of energy allocators are different. A comparison of these energy allocators is below in Table RN-3.

Table RN-3. Comparison of Company and Calculated Energy Allocators

	Energy Sales at Generation		
	EMM COSS	Calculated from Load Study	Difference
Residential	34.0%	32.1%	-1.9%
SGS	8.1%	8.2%	0.1%
MGS	13.6%	14.0%	0.4%
LGS	24.1%	24.8%	0.8%
LPS	19.6%	20.2%	0.6%
Lighting	0.6%	0.6%	0.0%
CCN	0.0%	0.2%	0.2%
LLPS	0.0%	0.0%	0.0%
Total	**100.0%**	**100.0%**	

While the differences between these class allocators are minor, they do affect the POD results presented above; as the adjusted hourly class loads are not identical to the hourly

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load profiles used to prepare the Company's COSS, the results necessarily vary from the results the Company would produce using the same POD method. Given more time to prepare this analysis, I could have reconciled the hourly load profiles through further discovery requests; however, due to delay caused by the Company's refusal to provide hourly generation data, the timeline for preparing this analysis was shortened.

Q. Please elaborate on this delay.

A. Part of the process of preparing a POD analysis is collecting hourly net generation data for each of a utility's generating plants. This step is a standard part of the discovery requests I make during every commission proceeding when I will be preparing a POD analysis, and until this rate case, this data has always been provided by the utility, along with plant-specific financial information. In this case, EMM has refused to provide hourly generation data or any plant-specific financial information, even though the generation data is in fact reported to the Commission on a monthly basis. This refusal to fulfill reasonable data requests has limited the time available to validate the results of my analysis, and will require me to provide updated results during a subsequent round of testimony. Thus, the results I present above should be seen as preliminary, though I expect they are directionally correct compared to the A&E method used by the Company and will not change significantly once finalized.

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IV. Revenue Apportionment

Q. What revenue apportionment approach does EMM propose in this proceeding?

A. EMM is proposing an equal increase across all classes of 15.19%.[53]

Q. What is the Company's justification for taking this approach?

A. The Company views this case as representing a transitional period towards jurisdictional alignment and preparation for LLPS activity and is therefore prioritizing rate stability in an effort to avoid premature cost alignment.[54] To that end, the Company is proposing an equal increase in the revenue allocation to each customer class of 15.19%.[55] The Company states that its COSS indicates a revenue deficiency in the residential class that would typically support shifting revenue. However, at this time it prefers a more gradual approach and, instead, proposes an equal increase across all classes.

The Company gives four primary reasons for why it believes a shift at this time would be premature: (1) LLPS revenues and costs aren't yet established since no LLPS customer was active during the Test Year; (2) LLPS cost allocation is incomplete due to insufficient operational data; (3) a pro forma LLPS revenue credit is already flowing to other classes and expected to grow; and (4) multiple rate design changes are happening simultaneously in Commercial and Industrial classes, making it prudent to wait and observe customer behavior and billing determinants before making further structural moves. Considering these factors, the Company believes that maintaining the current revenue allocation is the

[53] Direct Testimony of Graham Jaynes at 48:2
[54] Direct Testimony of Graham Jaynes at 53:2-6
[55] Direct Testimony of Graham Jaynes at 48:2

appropriate approach to minimize rate shock, preserve transparency, and allow for adjustments once LLPS rate design changes are incorporated.[56]

Q. Did you conduct an updated revenue allocation with your recommended changes to the Company's COSS?

A. No. Given the challenges with getting data for the POD analysis which I described above, I was not able to complete a final version of the POD analysis, and instead provided preliminary values which I intend to update in future testimony. Given the preliminary nature of this data I have chosen not to assess and comment on the Company's revenue allocation approach at this time and will also address that issue as part of future testimony, once I have finalized my COSS recommendations to the Commission.

V. Residential Customer Charge

Q. What change to the residential customer charge is EMM proposing?

A. The Company proposes to increase the current residential customer charge from $12.00 to $13.82, a 15.17% increase.[57] The percentage increase is consistent with its total recommended rate increase for the residential customer class, as discussed above. The Company further states that the COSS indicates a revenue deficiency in the residential class, whereby a customer charge of $18.33 may be warranted; it is not recommending a shift in revenue responsibility at this time and prefers a more gradualist approach.[58]

[56] Direct Testimony of Graham Jaynes at 48:3-50:2
[57] Direct Testimony of Graham Jaynes at 53:10-11
[58] Direct Testimony of Graham Jaynes at 53:11-13

Q. Does EMM provide any further justification for an increase to its residential fixed charge?

A. Yes. The Company claims that if one considers all costs in its COSS which it classifies as serving the customer function for the residential customer class, the total fixed costs would be $41.18/month.[59] It argues that its proposed residential fixed charge is well below this level and therefore appropriate.

Q. Do you agree with the Company's justification?

A. No. As described further below, the Company has not shown that its customer charge calculations reflect cost causation, because its customer-related unit cost calculations appear to be inflated. Further, cost causation is only a starting point in designing rates. It must be balanced against state policy goals and equity considerations, and the Company's proposal does not do so.

Q. What other considerations should be taken into account when proposing changes to fixed charges?

A. While rate stability and cost causation are elements of rate design, these elements must be balanced with state policy goals and equity considerations. These considerations are important because increases in fixed charges may conflict with state policy goals that encourage energy efficiency and may burden customers who hope to reduce their utility bills through energy conservation. Cost causation is also highly dependent on a utility's method of allocating costs. Certain methods, such as the minimum system method the Company uses, may over allocate costs recovered through fixed charges.

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[59] CONFIDENTIAL 26 MO Metro CCOS Proposed Class Structure Table 2 Tab

Q. Please describe the policy goals that the Commission should consider when contemplating changes to fixed charges for the residential customer class.

A. The Missouri Energy Efficiency Investment Act (MEEIA) established a framework for investor-owned electric utilities to implement demand-side management and energy efficiency programs approved by the Commission. As a result, EMM has developed a large portfolio of programs that help residential and commercial customers lower their energy use through rebates for energy efficient equipment, incentives for insulation and air sealing, and customer education. MEEIA allows these investments to be valued equal to traditional investments in supply and delivery infrastructure so that the Company may recover all reasonable and prudent costs associated with demand-side programs.[60]

Q. Why is increasing the fixed monthly customer charge problematic considering the state's energy efficiency programs?

A. Increases to the customer charge can undermine the progress achieved through energy efficiency programs because customers have less of an incentive to conserve energy. Since EMM's rates are set to recover a specific revenue requirement, any customer charge increases are offset by decreases to the volumetric charge, and vice versa. Increasing the fixed charge limits customers' ability to control their bill through reducing consumption, thus weakening incentives to conserve energy or invest in energy efficiency.

[60] Section 393.1075, RSMo

Q. Why does increasing the fixed monthly customer charge burden customers who hope to reduce their utility bills through energy conservation?

A. The proposed increase in the customer charge disproportionately impacts low-consumption customers because the customer charge, as a fixed component, represents a larger share of the total bill for low consumption customers. As the charge increases, these customers see a greater percentage impact on their bills relative to higher-consumption customers, for whom the fixed charge is a smaller portion of total costs. The bill impacts are particularly pronounced for low-income and energy efficient customers, who generally consume less electricity and are more sensitive to increases in fixed costs. For low-income customers, a higher customer charge reduces their ability to manage overall costs through reduced usage, while energy-efficient customers, who have already invested in lowering their consumption, see diminished benefits as more of the bill becomes fixed.

Q. What additional impact does this change have on low-income and energy-efficient customers?

A. Beyond the financial burden, increasing the customer charge reduces the price signal that encourages incremental energy conservation, potentially discouraging further household investments in efficiency and undermining broader energy reduction goals.

Q. Please explain how the Company's customer unit-related costs may be inflated.

A. As I will discuss in more detail below, the method the Company uses to functionalize distribution system and meter costs likely allocates costs to the customer function that would be better functionalized as either demand- or energy-related.

Q. What costs does the Company functionalize as customer-related in its COSS?

A. The Company functionalizes all meter-related costs and services as customer-related as well as a portion of its distribution system costs.[61]

Q. For the portion of distribution system costs that the Company considers customer-related, how does it split those costs?

A. EMM uses the minimum system method to split costs between the demand and customer-related portions of distribution plant.[62]

Q. Please explain the minimum system method.

A. The minimum system method assumes that a minimum distribution system can be built to serve the minimum load requirements of the customer.[63] This method requires the creation of a hypothetical system that would have been built if there was no demand and assigns the costs as customer-related. Said another way, the minimum system method assumes that there is some portion of the system whose costs are unrelated to actual customer demand.[64]

Q. Do you have any concerns with the Company's use of the Minimum System method for classifying costs as either demand- or customer-related?

A. Yes. While I recognize that the Minimum System method is a commonly used methodology, there are better methods for classifying the embedded costs of the system. The Minimum System method is grounded on an unrealistic concept of a hypothetical utility that has no basis in reality. The impact of using this method is that a higher

[61] Direct Testimony of Graham Jaynes at 38:4-13
[62] Direct Testimony of Graham Jaynes at 38:4-8
[63] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual,* January 20, 1992. P. 90.
[64] Weston, F. "Charging for Distribution Utility Services: Issues in Rate Design" Regulatory Assistance Project, 2000. P. 30.

proportion of costs are shifted onto customer classes with larger numbers of customers, primarily the residential customer class.

Q. Please explain why the Minimum System method is based on an unrealistic concept of a hypothetical utility.

A. The Minimum System method requires the creation of a hypothetical system that would have been built if there was no demand and assigns the costs as "customer related." Said another way, the Minimum System method assumes that there is some portion of the system whose costs are unrelated to actual customer demand.[65]

Close scrutiny of the method unveils its logical fallacy. To start, if there was no demand from customers, then the system wouldn't be built. So, the idea of a hypothetical minimum utility without any demand is without merit. It is customer demand that drives the need for any investment.

A cost should only be considered a customer-cost if the removal of a single customer removes the need for that equipment. With rare exception, the Company does not remove a utility pole or transformer from the distribution line if a customer disconnects from the system. The National Association of Regulatory Utility Consumers ("NARUC") Electric Manual defines customer cost as "costs that are directly related to the number of customers served."[66] The utility does not add a new pole or a new transformer each time a customer connects to the system. Rather, the components of the distribution system are sized to meet a certain level of demand for now and into the future.

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[65] Weston, F. "Charging for Distribution Utility Services: Issues in Rate Design" Regulatory Assistance Project, 2000. P. 30.
[66] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual,* January 20, 1992. P. 22

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Q. Can you provide an example of costs the Company functionalizes as customer-based using the minimum system method?

A. **____ ** The costs do not vary directly with the customer count, as discussed above and there are many utilities that classify all of those distribution costs based on demand, rather than the number of customers.

Q. Are there other accepted methods used by utilities to classify distribution system costs?

A. Yes, there are other accepted methods. These methods generally classify a greater portion of distribution system costs as demand- or energy-related. I am not advocating for a change to the Company's methodology at this time, but merely pointing out that moving to a different classification methodology will likely decrease those costs which the Company claims are customer-related for the residential customer class.

Q. Will the Company have the opportunity to recover its revenue requirement if the proposed customer charge increase is rejected?

A. Yes. Rates are designed to recover the Company's revenue requirement in a rate case. If the Commission rejects the proposed increase in its residential customer charge, then an offsetting amount is collected through the volumetric rate and can then be collected from

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[67] Confidential Support Paper Conduction Min System Analysis and Confidential Support Paper Conductor Min System Analysis

customers based on how much electricity each customer consumes. Moving cost recovery from fixed charges into volumetric charges will be revenue neutral for the company.

Q. What is your recommendation for the Commission regarding the company's residential customer charge?

A. Because the Company's proposal to raise the residential fixed charge will both undermine state policy goals and the fact that the Company's customer-related unit costs appear to be inflated, I recommend that the Commission reject the Company's proposal to increase the customer charge and maintain the current charge of $12.00 per month. The result of this recommendation would be that any additional revenue requirement the Commission approves for residential customers would be recovered through volumetric charges.

VI. Conclusion

Q. Does this conclude your testimony?

A. Yes.

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