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June 12, 2025

Ms. Lisa Felice *Via E-File*
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

RE: MPSC Case No. U-21859

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Direct Testimony and Public Exhibits of Caroline Palmer on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (Exhibit MEC-5 through MEC-23); and
- Proof of Service.
- Please note that Exhibit MEC-20C is confidential and will only be served on those with a Nondisclosure Certificate on file in this case.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Digitally signed by Christopher M. Bzdok
Date: 2025.06.12 18:11:15 -04'00'

Christopher M. Bzdok
chris@tropospherelegal.com

CC: Parties to Case No. U-21859

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for ex parte approval of certain amendments to Rate GPD.	U-21859

DIRECT TESTIMONY OF CAROLINE PALMER

ON BEHALF OF

**MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND
CITIZENS UTILITY BOARD OF MICHIGAN**

June 12, 2025

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

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. On whose behalf do you offer this testimony?

A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan (CUB), collectively referred to as "MNSC."

Q. Please summarize your experience in the field of utility regulation.

A. At Synapse, 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 seventeen dockets across nine 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 Exhibit MEC-5.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. I have not testified before the Michigan Public Service Commission (Commission). I have sponsored testimony before the Connecticut Public Utilities Regulatory Authority, the New Hampshire Public Utilities Commission, the Missouri Public Service Commission, the New York Public Service Commission, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the Oklahoma Corporation Commission, the North Carolina Utilities Commission, and the Nova Scotia Energy Board. I have also assisted with testimonies and regulatory analyses in numerous other jurisdictions.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-5:	Resume of Caroline Palmer
Exhibit MEC-6:	Discovery Response U21859-MNSC-CE-0023 Supp. 2
Exhibit MEC-7:	Discovery Response U21859-AG-CE-0015 (Supp 2).
Exhibit MEC-8:	Discovery Response U21859-DCC-CE-0052
Exhibit MEC-9:	Discovery Response U21859-MNSC-CE-0126
Exhibit MEC-10:	Discovery Response U21859-MNSC-CE-0032
Exhibit MEC-11:	Discovery Response U21859-MNSC-CE-0021
Exhibit MEC-12:	Discovery Response U21859-MNSC-CE-0025
Exhibit MEC-13:	Discovery Response U21859-MNSC-CE-0037
Exhibit MEC-14:	Discovery Response U21859-MNSC-CE-0076
Exhibit MEC-15:	Discovery Response U21859-MNSC-CE-0026
Exhibit MEC-16:	Consumers Response U21859-MNSC-CE-0075
Exhibit MEC-17:	Discovery Response U21859-DCC-CE-0007
Exhibit MEC-18:	Discovery Response U21859-MNSC-CE-0082
Exhibit MEC-19:	Discovery Response U21859-MNSC-CE-0033 Supp 3
Exhibit MEC-20C:	Discovery Response U21859-MNSC-CE-0033 Supp. CONF Att- Input4 Load Data & TY Sales, Rate Summary
Exhibit MEC-21:	Discovery Response U21859-MNSC-CE-0123
Exhibit MEC-22:	Discovery Response U21859-MNSC-CE-0034
Exhibit MEC-23:	Case No. U-20697, Jan. 15, 2022, Contribution in Aid of Construction Workgroup Report, p.9, 15.

II. SUMMARY

Q. Please summarize your conclusions.

A. My conclusions are as follows:

- The riskiness and magnitude of infrastructure investment associated with potential new data centers taking service in Consumers' territory necessitates robust safeguards to ensure that the new customers, rather than existing ratepayers, bear the risk of stranded investments should the data center have lower usage than anticipated or leave the Company's service territory. It also necessitates re-evaluating the traditional ways that Consumers would track and allocate the costs of its investments for data centers.
- Consumers' proposed revisions to its Large General Service Primary Demand ("GPD") Rate do not adequately protect other customers from the risk of reduced or departed data center load.
- Consumers' proposal does not address the risk of shifting a portion of the extra cost of serving data center load to other customers – even if the load does materialize.

Q. Please summarize your recommendations.

A. I recommend that the Commission direct Consumers to:

- Lower the eligibility threshold for Consumers' Rate GPD Data Center Provision to 50 MW.
- Add a 75% load factor threshold for customers below 100 MW.
- Create a new rate class for data centers as soon as possible.
- Extend the minimum contract term to 20 years.
- Increase the minimum billing demand requirement to 90% of contract capacity.

- Adjust COSS allocators to include the minimum billing demand.
- Expand the exit fee to include the infrastructure portion of the System Access Charge.
- Make exit fee waivers and contract capacity reductions subject to Commission review and approval.
- Require 42 months' advance notice before the end of the 15-year term and implement penalties if less notice is given.
- Apply the minimum billing demand and exit fee during the ramp-up period, proportional to milestone capacity levels.
- Strengthen the administrative fee by tracking and truing up actual costs, mandating the fee, and providing annual reporting on actual costs.
- Instead of allocating generation costs through traditional cost of service methods, directly assign data center such costs using IRP modeling with and without data center load to isolate incremental costs.
- If using traditional allocation, require data centers to pay for the cost of accelerated generation investment.
- Directly assign all dedicated distribution facility costs to data centers without CIAC offsets.

III. <u>Background: Consumers' Application and Data Center Expectations</u>

Q. Please summarize Consumers Energy Company's application.

A. In anticipation of large new data centers taking service, Consumers Energy Company (Consumers) proposes changes to its Large General Service Primary Demand ("GPD")

Rate "that are necessary to serve new data center load while protecting other customers."[1] Consumers describes unique risks associated with serving data center customers and introduces a set of provisions to protect other customers from the risk of stranded investments should the data center customer have lower usage than anticipated or leave the Company's service territory. The provisions include a minimum contract term, minimum billing demand requirement, financial security stipulations, exit fee requirement, contract capacity reduction, and upfront administrative fee.

Q. Describe Consumers' expectations for new data center load.

A. Consumers states that it has over 15 gigawatts (GW) of prospective data center load in the economic development pipeline.[2] Per the Company's data, as of May 13, 2025, 32 individual data centers, most requiring hundreds or even thousands of megawatts (MW), had inquired about locating in Consumers' service territory.[3] Of course, this load might not all materialize, as data centers likely inquire with multiple utilities and may choose to locate elsewhere or cancel their plans.[4] However, Consumers considers 2.65 GW of large load additions "to be more probable prospects" and has "engaged with the Transmission Owner" to evaluate the impacts of that 2.65 GW of load.[5]

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[1] Direct Testimony of Laura M. Connolly p. 3.

[2] Specifically, 15,849 MW of projects. *See* Ex MEC-6, U21859-MNSC-CE-0023 Supp. 2.

[3] U21859-DCC-CE-0045_Connolly_ATT_1 and Ex MEC-7, U21859-AG-CE-0015 Supp 2.

[4] Brian Martucci. "A fraction of proposed data centers will get built. Utilities are wising up." May 15, 2025. https://www.utilitydive.com/news/a-fraction-of-proposed-data-centers-will-get-built-utilities-are-wising-up/748214/.

[5] "[B]ased on advanced discussions with economic development and data center projects." MEC-8, U21859-DCC-CE-0052.

Q. How does prospective data center load compare with Consumers' current system?

A. Consumers' peak demand in 2024 was 7.5 GW.[6] Fifteen GW of new data center load could triple the Company's peak demand, while 2.65 GW could represent a 35% increase. Data center additions would have a greater relative impact on Consumers' energy generation, given that the facilities are expected to operate 24 hours a day, 7 days a week, 365 days a year.[7] An additional 2.65 GW of load operating at 90% load factor would consume 20,892,600[8] MWh in a year, which would require at least a 49% increase in Consumers' 2024 energy generation of 42,981,080 MWh.[9] These considerable new demand and energy requirements would occur over an extraordinarily short period of time[10] relative to historical load growth.[11] The unprecedented nature of this load growth also brings with it substantial risks due to unique uncertainty around potential reduction or elimination of data center load leading to stranded assets.[12] The riskiness and magnitude of potential infrastructure investment associated with Consumers' proposal necessitates careful consideration of safeguards to ensure that the new customers bear that risk, rather than

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[6] MPSC FORM P-521 (Rev. 12-00), p.401. Accessed at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/regulatory/reports/annual-utility-elec/2024/Consumers-Energy-P-521-YE2024.pdf?rev=d531b85b5baf4aa29236ef1885738205&hash=8EBC514F8BBF2DC329759D1937E8E1FA.

[7] Consumers' Application, para. 3.

[8] 2,650 MW * 8,760 hours * 0.9 load factor.

[9] MPSC FORM P-521 (Rev. 12-00), p.401. Accessed at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/regulatory/reports/annual-utility-elec/2024/Consumers-Energy-P-521-YE2024.pdf?rev=d531b85b5baf4aa29236ef1885738205&hash=8EBC514F8BBF2DC329759D1937E8E1FA.

[10] Although Consumers doesn't specify the expected timeframe for the probable 2.65 GW, it provided time estimates for a portion of its data center inquiries, which, if accurate, would represent 6 GW of new load by the end of 2030. *See* U21859-AG-CE-0015 Supplemental

[11] Over the past 10 years, Consumers' highest annual peak demand has only exceeded its lowest peak demand by 9%. Ex. MEC-9, U21859-MNSC-CE-0126.

[12] Connolly Direct p. 9-10.

existing ratepayers. It also necessitates re-evaluating the traditional ways that Consumers would track and allocate the costs of its investments for data centers.

IV. Consumers Should Strengthen Its Proposed Protections

Q. Describe the applicability of Consumers' Rate GPD Data Center Provision.

A. The proposed tariff revisions apply to data centers with a load of 100 MW or more at a single site or aggregated among more than one site in the Company's service territory. The Company justified this load threshold as "intended to address the large hyper scale data centers [which] tend to be around 100 MW or greater"[13]

Q. Do you recommend a lower eligibility threshold for Consumers' Rate GPD data center provision?

A. Yes. Consumers' proposed 100 MW threshold is rather high. The recently approved settlement agreement in Indiana Michigan Power Company's (I&M) Industrial Power tariff set a threshold of 70 MW at an individual site or 150 MW on an aggregated basis.[14] In its recent rate case, Dominion Energy Virginia (Dominion) proposed to create a high load new rate class including all existing and new customers with demand above 25 MW on contiguous sites and measured or expected load factor of at least 75%.[15] Consumers has received inquiries for potential service in the last twelve months from potential data center customers below 100 MW, sized 4 MW, 10 MW, 50 MW, 60 MW, 70MW, and 75 MW.[16]

[13] Ex MEC-10, U21859-MNSC-CE-0032.

[14] Order of the Commission. February 19, 2025. Cause No. 46097. In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to Its Industrial Power Tariff – Tariff I.P. p.31.

[15] Direct Testimony of Stan Blackwell. Dominion Energy Virginia. Case No. PUR-2025-00058. p.11.

[16] Ex. MEC-7, U21859-AG-CE-0015 (Supp 2).

Given the relatively lower demand of the existing customers in Consumers' Rate GPD class – 79% of Rate GPD customers are below 1 MW, and the largest customer is 28 MW[17] – I recommend that Consumers lower the eligibility threshold to 50 MW. A lower threshold would capture a broader range of potential data center customers, limiting more of the potential risk described above.

Q. Should the Rate GPD Data Center provision also have a load factor threshold?

A. Yes. It would also be reasonable for Consumers to combine a load factor threshold with the size threshold for customers below 100 MW, given the unique load profile of data centers. Unlike other commercial or industrial businesses that run varying shifts of production or only operate during normal business hours, data centers require consistent, high levels of demand.[18] Therefore, I recommend that Consumers update eligibility for its Rate GPD Data Center Provision to 50 MW with a 75% load factor threshold for customers below 100 MW.

Q. Describe a potential consequence of data centers using Rate GPD rather than a separate rate?

A. Using Rate GPD rather than a separate rate could result in substantial future rate increases for other customers in the class. Although Consumers considers Rate GPD to be "reasonable for new data center customers at this time,"[19] future data center customers joining Rate GPD could be 1,000 times larger than the other customers on Rate GPD. As

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[17] 779 ÷ 989 = 0.79. *See* U21859-MNSC-CE-0070_Attachment 1.

[18] Consumers' Application, para. 3.

[19] Consumers' Application, para. 6.

currently specified, even the smallest data center provision customer (100 MW) would be over three times larger than the largest Rate GPD customer (28 MW). Thus, there are likely to be cost allocation consequences to the current customers, as Consumers' cost of service study (COSS) begins to allocate costs to the class based on average demand and energy characteristics that are significantly larger than before. If Consumers sets uniform demand and energy rates for the class's data center and non-data center customers based on average revenue requirements and usage characteristics, Rate GPD prices are likely to rise for current customers.

Q. Why isn't Consumers proposing to create a new rate class for data centers now?

A. Consumers is reluctant to create a new data center class without customer load data, as it "typically uses three years of actual, historic load data to develop a load shape for cost allocations."[20] The Company explains that once large-scale data centers start to come online, it expects to use the load data to analyze putting data centers in their own cost of service column and developing a rate specific to data centers.[21] .

Q. Could the Company create a new rate class without three years of data?

A. Yes. "The Company could develop a rate without any actual load data" by "making assumptions about the prospective customer load profile to assign costs in the COSS."[22] It seems that Consumers' current approach already makes assumptions about the data center load profile by lumping the new customers in with the current Rate GPD class. Further, my

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[20] Ex MEC-11, U21859-MNSC-CE-0021.

[21] Connolly Direct p. 5.

[22] Ex MEC-11, U21859-MNSC-CE-0021.

understanding is that Consumers already serves a data center customer that it could use to inform its assumptions.[23] Consumers has not specified how many customers' load profiles the Company would need to aggregate before it could use the three years of load data to make a new, publicly vetted COSS customer class.

Q. What do you recommend regarding the creation of a new data center rate class?

A. I recommend that Consumers create the new rate class as soon as possible – based on terms no less stringent than approved for the Rate GPD data center provision – and require all existing data center customers to take service on that rate. Doing so will better reflect cost causation associated with data center customers under traditional cost of service methodologies, facilitate direct assignment of data center-specific costs as I discuss in Section V, and generally better ensure that other Rate GPD customers do not subsidize those unique customers' costs.

Q. What minimum contract term does Consumers propose?

A. Consumers proposes to require data center customers to enter into a rate contract term for an initial period of at least 15 years in order to receive electric service. The 15 years would commence after a negotiated ramp up period of not greater than five years. Consumers states that 15 years "reasonably reflects the term of the power supply resources the Company anticipates needing to procure in order to serve new data center loads"[24] and "ensures that the customer…causing the assets to be procured is committing to taking

[23] U21859-MNSC-CE-0020(b).

[24] Consumers' Application, para. 8

service for, and paying for, the assets in place to serve them."[25] The Company also strives to strike a balance with the life of the server infrastructure the data center will put into place – which evidently needs to be refreshed every five years[26] – while "remaining competitive with other utility data center tariffs."[27]

Q. Is this contract term appropriate?

A. No, because it would not match the lifespan of resources procured to serve this load. Consumers acknowledges that "self build construction of new assets generally includes resources with a 30 year or greater depreciation schedule while PPAs are generally 15- to 25-year agreements."[28]

A term that is shorter than the life of most assets built or procured to serve data center customers could result in cost shifting to other customers should the data center load depart or decrease after 15 years. The data center therefore may not contribute to paying those facility costs for the full depreciation life of the generating assets needed to serve them. It is also unclear why the Company would consider the life of the data center's hardware when determining the length of a contract term intended to ensure payment for utility investments; server hardware life has little to do with protecting customers from Consumers' stranded grid investments. While 15 years is indeed comparable to other jurisdictions' contract length, there are some with a longer term, such as Kentucky, where

[25] Connolly Direct p. 6 lines 6-8.

[26] U21859-MNSC-CE-0080.

[27] Ex MEC-12, U21859-MNSC-CE-0025.

[28] Connolly Direct p. 6 lines 4-6.

the Public Service Commission (PSC) approved a 20 year minimum contract term for Kentucky Power's large load tariff.[29]

Q. Describe Consumers' minimum billing demand requirement and its rationale.

A. Consumers proposes requiring new data center customers to pay a monthly minimum billing demand for the term of their rate contract, to be 80% of the data center's contract capacity and applied to its maximum demand and on peak demand, and all charges that apply to those measurements. Consumers contends that the minimum billing demand requirement is intended to "ensure that investments in the system will be utilized and paid for by the data centers that create the need for such investments rather than placing the risk of paying for the associated incremental investment on other customers should the data center have lower usage than anticipated."[30] The Company has also stated that it set the minimum billing demand at 80% "based on benchmarking against other utility data center tariffs."[31]

Q. Do you recommend a higher minimum billing demand requirement?

A. Yes. Consumers does not demonstrate that an 80% minimum billing demand ensures that data centers utilize and pay for the system investments they require. In fact, Consumers did not assess the potential impact of a minimum billing demand other than 80%.[32] Further, while 80% is comparable to other jurisdictions' minimum billing demand requirements, it is on the lower end. The Kentucky PSC approved a 90% minimum monthly billing

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[29] https://psc.ky.gov/pscscf/2024%20Cases/2024-00305/20250318_PSC_ORDER.pdf.

[30] Consumers' Application, paragraph 8.

[31] Ex MEC-13, U21859-MNSC-CE-0037(a).

[32] Ex MEC-13, U21859-MNSC-CE-0037(b).

demand[33] for Kentucky Power's large load tariff. AEP Ohio's proposed settlement sets an 85% minimum billing demand for loads above 116 MW.[34] I recommend raising Consumers' minimum billing demand requirement to 90% to ensure that Consumers collects payment from data centers for a greater portion of the investments made for them.

Q. Does the minimum billing demand requirement impact cost allocation?

A. Yes. Under traditional cost allocation methodologies, it is important that Consumers update its cost of service study (COSS) to reflect the minimum billing demand requirement. Traditionally, demand allocators are based on actual load data, so costs would be allocated to classes based on actual demand rather than minimum billing demand. For example, a data center customer with 100 MW of contract capacity but a peak demand of 60 MW would be treated as 60 MW for allocating demand costs. However, the revenues from that customer would reflect 80 MW of demand due to the proposed 80% minimum billing demand requirement. This discrepancy would underrepresent the cost to serve the customer class, causing it to appear to have higher revenues than costs, or a very high rate of return. It would also overrepresent the cost to serve other customer classes, appearing as though they are responsible for a higher proportion of system costs, when those costs are actually attributable to investments made for data centers. Other customer classes would therefore appear to have a lower rate of return, artificially justifying higher rate increases for those customers. By imposing a minimum billing demand requirement on data center customers,

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[33] https://psc.ky.gov/pscscf/2024%20Cases/2024-00305/20250318_PSC_ORDER.pdf.

[34] The minimum billing demand decreases incrementally below 116 MW. The Public Utilities Commission of Ohio has not yet ruled on the case. Joint Stipulation and Recommendation, Exhibit B. October 23, 2024. Case No. 24-508-EL-ATA. https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24J23B55758I01206.

the Company is acknowledging that it incurred at least that portion of demand costs for those customers; they should be allocated accordingly in the COSS.

Q. How do you recommend accounting for the minimum billing demand in the COSS?

A. To reflect the minimum billing demand in its COSS allocators, Consumers should adjust the allocator data to include any additional demand that would have been billed to the class under the minimum demand requirement. I recommend that Consumers incorporate this methodology into its next rate case COSS filing regardless of whether data center load has begun taking service, to begin the process of finalizing the methodology and to inform any data collection that the Company may need to put in place once data center load does materialize. Ideally, this recommendation will not be necessary if the Commission approves my recommendations in Section V to initiate a more robust method of direct cost assignment to data centers, but incorporating the minimum billing demand in its COSS is necessary in the meanwhile.

Q. Have other jurisdictions incorporated a minimum billing demand in the COSS?

A. Yes. Dominion proposed such an adjustment in its recent rate case. Dominion noted that the adjustment better matches the costs incurred to meet the expected requirements of these large customers with the customers causing those costs to be incurred. "In addition, the adjustment ensures that the revenues associated with these minimum charges do not artificially inflate the class rate of return while the associated costs are allocated to other classes, making their rates of return appear to be lower."[35]

[35] Direct Testimony of Robert E. Miller. Dominion Energy Virginia. Case No. PUR-2025-00058. p.30-32.

Q. Describe the exit fee requirement and its rationale.

A. Consumers proposes to recover a fee if the data center customer stops taking full service from the Company during the contract term. Calculating the fee involves "multiplying the Minimum Billing Demand by the number of months remaining in the rate contract term as of the date the Customer ceases to take power supply service."[36]

Q. Do you have concerns with the Company's proposed exit fee provision?

A. Yes, I have several concerns:

- First, I am concerned that the exit fee does not cover the full extent of the costs incurred to serve the data center, potentially resulting in cost shifting to other customers should the data center depart. Specifically, the exit fee does not include costs that are recovered through the System Access Charge. My understanding is that the System Access Charge includes the cost of service drops, meters, account maintenance, and distribution transformers.[37]
- Second, the Company's proposal would allow it to reduce the exit fee based on its own determination that doing so would not harm other customers, without review or approval by other parties or the Commission.
- Third, Consumers' exit fee provision does not require large load customers to provide

[36] Exhibit No. A-1 (LMC-1) Page 3.

[37] Commission Order in Case No. U-17767, p 117, states that "the customer charge should only include the cost of the service drop, metering, account maintenance, and distribution transformers." December 11, 2015.

advance notice of termination, which is inconsistent with best practice.

Q. What other costs should be included in the exit fee provision?

A. The exit fee should not be limited to the minimum billing demand; it should also include Rate GPD's System Access Charge, which is designed to cover the marginal cost of connecting a customer to the system. [38] If a data center departs Consumers' territory, the costs associated with the data center customer's meter and service drop would be recovered from other customers unless another customer takes service at the same premise. Therefore, the departing data center should continue to pay those costs so as to avoid saddling other customers with these costs. Specifically, I recommend that Consumers' exit fee include at least the infrastructure portion of Rate GPD's System Access Charge (e.g., the cost associated with the service drop, meter, and transformer), if Consumers can demonstrate that it would not continue to incur any of the account maintenance components once the customer departs.

Q. Do any other jurisdictions include customer costs in the exit fee?

A. Yes. For example, The I&M settlement agreement includes the monthly customer charge in a monthly minimum charge, which customers must pay as their exit fee.[39] Likewise, Evergy Kansas recently proposed to include the monthly customer charge in its exit fee.[40]

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[38] Commission Order in Case No. U-17767, pp 119-120. December 11, 2015.

[39] Order of the Commission. February 19, 2025. Cause No. 46097. In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to Its Industrial Power Tariff – Tariff I.P. p.33-34.

[40] Direct Testimony Bradley Lutz. February 11, 2025. Docket: 25-EKME-315-TAR. Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc. for Approval of Large Load Service Rate Plan and Associated Tariffs. p.15.

Q. Please explain your concerns regarding Consumers' proposal to reduce the exit fee if it determines that doing so would not harm other customers.

A. Consumers' proposal does not guarantee the exit fee. Instead, Consumers proposes that it could "reduce the exit fee if it determines, in its sole discretion, that the loss of customer's load will not harm the Company or its other customers."[41] Specifically, the Company would determine if there is a new customer that could be served by the resources which were used to serve the exiting customer's load.[42] Similarly, Consumers proposes to allow a one-time contract capacity reduction if it makes the same determination, in its sole discretion, described for the exit fee: that there is another customer that could be served by that load.[43] If so, Consumers would determine that the requested reduction would not create a stranded asset or otherwise shift costs to the Company or its other customers.[44]

For both the exit fee and contract capacity reduction, Consumers has proposed to determine the impact of the departed or reduced load and, in its sole discretion, relieve the data center customer where it determines no harm or cost increase. The Company has not committed to publicly file or to share that analysis with parties, beyond its plan to report on the number and MW of requested capacity reductions and the number of contract termination notices and exit fees applied. Nor has the Company committed to any Commission review of such determination.

[41] Exhibit No.: A-1 (LMC-1) Page 3.

[42] Ex MEC-14, U21859-MNSC-CE-0076.

[43] Ex MEC-15, U21859-MNSC-CE-0026.

[44] Consumers' Application, para. 10.

I am concerned that, as currently described, the Company's criteria for determining harm to other customers has not been adequately supported and that such analysis would not be subject to verification.

Q. What modification do you recommend to the potential waiver of the exit fee and one-time contract capacity reduction?

A. I recommend that the determination of harm for both the exit fee and contract capacity reduction should be subject to review and approval by the Commission. Specifically, I recommend that Consumers be required to update its tariff to set forth that it will submit a filing to the Commission and that parties have the opportunity to evaluate the analysis in a contested case. The filing should demonstrate that the terminated or reduced capacity will:

- serve new data center customers,
- expand service to existing data center customers, or
- otherwise secure offsetting expected revenues.

Consumers should make this demonstration at each level of the power system. For production and transmission, comparably-sized new load may be able to offset departing load. For distribution, the departing or downsized customer should continue to pay 1) delivery demand charges based on its original minimum billing demand and 2) the infrastructure portion of its monthly system access charge as I specified above, unless a new customer takes service at the same premise or Consumers otherwise demonstrates that those distribution facilities will not be paid for by its other customers. Duke Energy

Carolinas' Service Regulations contain a similar provision in the event that a customer terminates service before the initial agreement term expires.[45]

Q. Please describe best practices regarding requirements that large load customers provide advance notice prior to substantial capacity reductions or departure.

A. Utilities rely on accurate forecasts of future load to make system capacity investments and avoid over-investing in capacity. Jurisdictions across the country have begun to recognize that it is critical to require large load customers to provide adequate advance notice of load reductions or departure to protect remaining customers. As the Virginia Joint Legislative Audit and Review Commission stated, "Requiring advance notice of at least several years is important so that utilities can appropriately plan for system needs, secure needed capacity, and protect other customers from rate fluctuations."[46] The aforementioned I&M settlement requires large load customers to give 42 months' written notice prior to terminating a contract. Evergy Kansas recently proposed to require large load customers to provide written notice 36 months prior to the requested date of termination. Customers seeking to terminate service with less than 36 months' notice must pay an additional early

[45] The departing customer must pay at least the net present value of its remaining minimum bills less the minimum bills of a successor customer who takes service at the same premise. Service Regulations. Duke Energy Carolinas, LLC (South Carolina). https://www.duke-energy.com/-/media/pdfs/for-your-home/rates/electric-sc/scleafs.pdf?rev=f704a1fd8b7d4a6c9775e8c7b124c2d2.

[46] Joint Legislative Audit and Review Commission. Data Centers in Virginia: Report to the Governor and the General Assembly of Virginia. JLARC Report 598. December 9, 2024, at 54-55.

termination penalty equal to double the normal minimum charge for each month less than the required 36-month required notice.[47]

Q. What advance notice do you recommend requiring?

A. If the Commission accepts my recommended requirements for determining harm for both the exit fee and contract capacity reduction, it is not necessary to require advanced notice or penalty for these provisions, as the data center customer will continue paying charges associated with its original contract capacity for the full contract term unless parties and the Commission agree that there is no harm. However, as the end of the 15 year term approaches, Consumers must be able to plan around the data center's future load. The departure of the customer, even after 15 years, will have significant impact on the Company's planning, such as whether it needs to procure extra resources for other new load or not. I therefore recommend that Consumers require large load customers to provide 42 months' advance notice before the end of the 15 year contract term and implement penalties equal to the minimum billing demand and system access charge for each month less than the 42-month required notice.

Q. Describe Consumers' proposed ramp-up schedule.

A. Consumers proposes a negotiated ramp up period not exceeding five years, as determined by the Company.[48] While not detailed in the proposed tariff language, the Company explained in response to discovery that it will work with each prospective customer to

[47] Direct Testimony Bradley Lutz. February 11, 2025. Docket: 25-EKME-315-TAR. Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc. for Approval of Large Load Service Rate Plan and Associated Tariffs. p.15.

[48] Exhibit No.: A-1 (LMC-1) p.3.

determine specified capacity milestones leading up to the full contract capacity, such as in the table below, reproduced from Consumers' discovery response.[49] The schedule would include when the customer needs service based on the customer's business plans and when the Company is able to provide that service. The Company does not intend to require, and the proposed tariff language does not require, customers to pay minimum demand charges (which encompasses On Peak Demand, Transmission, and Max Demand charges) during the ramp up period.[50] While the proposed tariff provisions do not apply any exit fee during the ramp up period, Consumers stated during discovery that it believes the exit fee should apply during the ramp up period and that it will support clarifying that in the tariff language.[51]

Date	Target Contract Capacity
1/1/2026	50 MW
1/1/2027	150 MW
1/1/2028	250 MW
1/1/2029	350 MW
1/1/2030	500 MW

Q. Do you recommend greater protections during the ramp-up provision?

A. Yes. I recommend that the minimum billing demand requirement and the exit fee apply during the ramp up period. These provisions should be sized to individual capacity milestones; for example, in year three of the table above, the customer would be responsible for a minimum billing demand of 90% of the 250 MW contract demand

[49] U21859-MNSC-CE-0074.

[50] Ibid.

[51] Ex MEC-16, U21859-MNSC-CE-0075.

specified in year three of the ramp-up schedule, or for a 15-year exit fee beginning in year three based on 90% of the 250 MW contract demand specified in year three.

Q. Describe Consumers' proposed upfront administrative fee for project proposals.

A. Consumers' proposed data center tariff provisions state that the Company may, at its discretion, charge potential data center customers an upfront fee for each project proposal, to collect the costs of the needed engineering study, supply planning, project management, economic development, and rates support.[52] Consumers proposes that such fee would be capped at $100,000 per individual site studied.

Q. Do you recommend strengthening the proposed administrative fee provision?

A. Yes. Vetting and developing proposals for potential data center customers could be a costly endeavor. Given the potential magnitude of such costs, and the sometimes speculative nature of data center proposals, those costs should be fully borne by the prospective data centers, not Consumers' other customers. Consumers' proposed administrative fee provision suggests that the Company generally agrees that the prospective data center customer should pay the costs associated with vetting it, but I recommend strengthening that provision in at least four ways to fully achieve that outcome:

- First, I recommend that Consumers track the actual costs of providing project proposals to prospective data center customers, and true up the fee if those costs are greater or less than the $100,000 upfront fee.

[52] Consumers' Application, para. 7.

- Second, Consumers' annual reporting should not only provide information on the number of administrative fees assessed, but also the magnitude of those fees and how they compare to actual costs.
- Third, the fee should be mandatory, not at the discretion of Consumers. In particular, I recommend that the Company remove "at its discretion" from the proposed data center provision tariff and instead make clear that the fee will be charged for all data center project requests. Given that the Company stated in response to discovery that it "does not contemplate a situation in which it would not impose the administrative fee on a project request above 100 MW,"[53] such change should not be controversial.
- Finally, I recommend that Consumers update its tariff language to reflect that it will collect the fee upfront.

V. <u>Consumers Should Mitigate Indirect Cost-Shifting from Data Centers</u>

Q. Does Consumers' proposal adequately address potential sources of cost-shifting?

A. No. Consumers' proposal tries, though as discussed above only partially succeeds, to solve one problem: the risk of less-than-forecasted or departed data center load. This risk is a critical concern that could have unprecedented consequences, as Consumers highlights throughout its application. Consumers has therefore identified provisions that it contends will "protect other customers from stranded assets and increased costs should the data

[53] U21859-MNSC-CE-0066.

center load not materialize after resources are committed to serve them or the load is not in place for as long as expected."[54]

However, Consumers must also prevent another problem: the risk of shifting a portion of the extra cost of serving data center load to other customers – even if the load does materialize.[55]

Q. How could the cost of serving data center load impact other customers?

A. Consumers has repeatedly stated that it must make significant investments in capacity, energy, and distribution to serve the requested data center load.[56] If Consumers tracks and allocates those costs among its customer classes using traditional methodologies and processes, other customers will likely end up paying for substantial portions of that investment.

Q. Is it reasonable to apply traditional cost of service methods to the allocation of costs associated with serving data center load?

A. No. While some degree of cost socialization is inherent in utility cost allocation, the scale of the anticipated investment described in Section III calls for reevaluating its treatment. Allocating these investments via the cost of service study would exacerbate the COSS's existing imprecisions to an unjust and unreasonable level.

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[54] Connolly Direct p.4.

[55] Under MCL 205.54ee(10)(e)(x)(c), an enterprise data center "will not take electric service under" "A rate that causes residential customers to subsidize the costs incurred to provide electric service to the facility."

[56] Connolly Direct p.6.

Q. How does Consumers plan to track and allocate the cost of investments required to serve data center load?

A. Consumers does not plan to separately track or allocate costs associated with data center load. Instead, the Company plans to determine the required generation investment for the entirety of its service territory, not specifically for data center load, using its integrated resource plan process.[57] For allocating costs, Consumers is not proposing to directly assign any costs to data centers but rather to allocate them the same way it treats other customers.[58] Consumers allocates the cost of providing service to each customer class using its COSS.[59]

Q. Why does Consumers not propose to separately track or allocate costs associated with serving data center load?

A. The Company's decision to maintain this traditional approach is premised on the assumption that system costs are generally shared by or attributable to a mix of customer classes and that the COSS properly allocates those costs to the customers who cause them. In other words, that the incremental costs of serving data centers should be treated as shared among all customers because the costs will flow to the appropriate classes through the traditional methods.

Q. Could Consumers separately identify and directly allocate data center costs?

A. I expect that this would be possible given that the magnitude of incremental data center costs is likely to be large enough to reasonably estimate, track and attribute to the customer

[57] Ex MEC-17, U21859-DCC-CE-0007.

[58] Ex MEC-18, U21859-MNSC-CE-0082.

[59] U21859-MNSC-CE-0034 and U21859-MNSC-CE-0078.

class, unlike the incremental costs to supply a new residential subdivision or business district.

Q. Do you recommend that Consumers separately identify and directly allocate data center costs?

A. Yes, for several reasons. First, the ability to isolate costs of this magnitude calls into question the necessity and reasonableness of treating them as shared costs and using a COSS to allocate them at all. Second, a cost of service study is an inherently imprecise tool in which cost analysts make numerous subjective determinations that may dramatically impact the study results. Consumers' allocation methodologies do not adequately reflect the costs incurred to meet the operating characteristics of new data center load. I address each of these issues below.

a. <u>Generation Costs</u>

Q. What is the magnitude of incremental generation costs to serve data centers?

A. Parties asked the Company several times to share estimates of the incremental generation costs,[60] but Consumers stated that load growth studies and decisions regarding the addition of new peak load and required generation supply will be included in the Company's next integrated resource plan, which will be filed in 2026.[61]

However, Consumers did ultimately provide a cost estimate for a hypothetical 500 MW, 100% load factor customer, using publicly available data from NREL to estimate a 500

[60] U21859-MNSC-CE-0082(b). U21859-DCC-CE-0008. U21859-DCC-CE-0054.

[61] U21859-DCC-CE-0054.

MW PPA.[62] The incremental PPA cost estimate to serve the 500 MW customer is $544 million for the test year.[63] Given that Consumers expects 2.65 GW of probable data center prospects as described above, its incremental "probable" data center generation costs would be $2.9 billion when scaling up the PPA cost for 2.65 GW.[64] For context, Consumers' latest cost of service study indicates that the Company had $1.806 billion total fuel and purchased & interchange power expense.[65] Therefore, $2.9 billion would represent more than double – a remarkable 160% increase – in that cost category.

Another way Consumers might serve data center load is through generation investment rather than PPAs. In the I&M docket, I&M's witness estimated incremental generation investment based on an average resource cost of $2,000/kW.[66] For Consumers to build 500 MW of capacity for the hypothetical new customer at that price – not including reserve margin or variable generation expense – would cost $1 billion.[67] Extrapolating that to Consumers' 2.65 GW of probable data center prospects, the incremental "probable" data center investment would be $5.3 billion.[68] Consumers' latest cost of service study indicates that the Company has $3.528 billion of production plant in service.[69] For Consumers to serve 2.65 GW of data center load using this approach would more than double the amount

[62] Ex MEC-19, U21859-MNSC-CE-0033 Supp 3.

[63] Ex MEC-20C, U21859-MNSC-CE-0033 Supp CONF, Expanded, "Input4 Load Data & TY Sales."

[64] 5.3 * $544,396,000

[65] This cost of service study was approved in Case No. U-21585 on March 21, 2025. U21859-DCC-CE-0009_U-21585 COSS FOR ORDERATTC.xlsm.

[66] Direct Testimony of Andrew J. Williamson. July 19, 2024. Cause No. 46097. In The Matter of the Verified Petition Of Indiana Michigan Power Company for Approval of Modifications to Its Industrial Power Tariff – Tariff I.P.

[67] 500 MW *1,000 * $2,000.

[68] 5.3 * $1 billion.

[69] U21859-DCC-CE-0009_U-21585 COSS FOR ORDERATTC.xlsm.

of production plant it currently requires to meet the demand of its entire power system. Of course, 2.65 GW is just a fraction – less than 20% – of the 15 GW in Consumers' pipeline. If more data enter load were to materialize, the costs would be even higher.

Q. If Consumers must more than double its generation investment for data center customers, is it reasonable to allocate those costs to all customer classes?

A. No. Allocating a 150% increase in plant investment across all customer classes when that new plant investment identifiably serves a particular class is unnecessary, unjust, and unreasonable. Incremental costs of this magnitude should compel Consumers, the Commission, and intervening parties to scrutinize traditional approaches to measuring and assigning costs when they are attributable to a small group of customers with unprecedented volumes of new load.

Q. Did Consumers estimate the interclass impact of its hypothetical 500 MW PPAs?

A. Yes. Consumers input the production cost assumptions into a cost of service model which calculates the impacts of hypothetical new data center load. Adding a 500 MW customer served through PPAs increased each customer class's rates as shown in Table 1.[70] Every customer class would experience a production rate increase, meaning that every customer class would pay for part of the data center's PPA costs.[71]

Table 1: Estimated Production Rate Change With 500 MW Data Center Load

Residential	Commercial	Primary+GSG	Lighting	GPD 1
9.1%	8.8%	5.1%	4.2%	10.2%

[70] Ex MEC-20C, U21859-MNSC-CE-0033 Supp CONF, Expanded, "Rate Summary."

[71] Although Consumers' hypothetical cost of service model did not add any distribution costs associated with new data center load, it did calculate that distribution rate changes would decrease, although less than the calculated production increases.

Q. How would Consumers' COSS allocate generation plant investment made for data centers?

A. Consumers allocates production costs as 75% demand, based on four coincident peaks, and 25% energy, based on total consumption (4CP 75/0/25).[72] The demand portion of this allocator combines the Company's various demand resources into one cost pool and assigns it to customers based on their coincident demand, rather than based on the specific resources they use more of. Because baseload plants tend to have higher capital costs than peaking plants, customers that use a higher share of the baseload resource are responsible for a higher share of the utility's costliest resources. Data center customers are expected to use continuous power, which would likely translate to a higher proportion of baseload, while other customers use power at different rates across the day and year. Therefore, data center customers would be allocated a relatively lower proportion of generation costs than incurred to serve them.

Q. How could Consumers improve its COSS methodologies?

A. Ideally, Consumers would use a production allocation methodology that examines how each customer class utilizes each generation resource, such as the probability of dispatch method.[73] However, as I explained above, incremental data center costs should not be allocated using the cost of service study, given the unprecedented magnitude of those costs, because the COSS would allocate costs to all customer classes.

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[72] Direct Testimony of Laura M. Connolly. May 2024. Case No. U-21585. p.10

[73] I am not recommending in this case that the Commission change the method of production cost allocation used in Consumers' COSS.

Nonetheless, if indeed the Commission chooses to continue to use traditional methods to allocate incremental data center costs, Consumers should require data center customers to pay for the cost of accelerated investment.

Q. Please explain what you mean by requiring data center customers to pay for the cost of accelerated investment.

A. Data center load will require generation buildout sooner than there otherwise would have been. Data centers should therefore pay the cost of that acceleration – the time value of money – and credit it to customer classes in a future COSS. Evergy Kansas recently proposed a version of this concept in its large load power rate plan, which it filed outside of a rate case. Evergy expects that "accelerated investment would increase costs for all customers" and thus designed its System Support Rider to "help mitigate potential cross-subsidization."[74] The rider aims to collect a portion of the net present value revenue requirements of a generic generation investment, and then distribute the revenues produced to the non-large-load classes during a subsequent rate case. While Evergy's rider is imprecise, implementing a well-designed mechanism of this type is essential if Consumers continues to use its COSS to allocate generation costs attributable to data centers, regardless of the allocator used.

[74] Direct Testimony Bradley Lutz. February 11, 2025. Docket: 25-EKME-315-TAR. Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc. for Approval of Large Load Service Rate Plan and Associated Tariffs. p.29.

Q. Please identify alternative ways to track incremental generation costs and assign them to data center customers.

A. Consumers could consider a couple of approaches. Under a more traditional planning paradigm, Consumers' IRP process could produce an optimal system expansion plan with and without the large load additions, clearly identifying the incremental costs that would be incurred by the data center customers. Consumers could directly assign those customers the cost of their system expansion by designing the data center tariff rate to collect the revenue requirement associated with that incremental system expansion cost. Under this approach, data center customers may no longer need to contribute to the majority of the existing power system costs, though they should contribute to system costs – such as reserve margin costs – if they expect to utilize the rest of the system in contingency circumstances, including the utility's black-start resources, which is likely given that this approach does not contemplate a dedicated, islanded system for the data centers. Other jurisdictions have conducted IRP runs with and without data center load, such as Dominion Virginia.[75]

b. <u>Distribution Costs</u>

Q. What is the magnitude of incremental distribution costs to serve data centers?

A. Consumers estimated a range of $28 million to $34 million costs for distribution transformers, excluding outliers, to serve a new 100 MW load.[76] However, distribution

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[75] Virginia Electric and Power Company's SCC Directed 2024 IRP Supplement. November 15, 2024. Case No. PUR-2024-00184. Virginia Electric and Power Company's 2024 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.

[76] Ex MEC-21, U21859-MNSC-CE-0123.

interconnection costs could include new distribution lines built between existing or new transmission facilities and the new dedicated customer substation, distribution switching station(s), dedicated customer substation(s), line routing and easement acquisition, and/or power factor correction equipment.[77] It does not appear that Consumers estimated the cost of equipment beyond transformers, leaving great uncertainty as to the potential cost of all distribution equipment needed to connect new data centers.

Q. How does Consumers plan to allocate these costs?

A. The Company does not currently direct assign costs to specific customers. Even for the aforementioned dedicated distribution substation and the other associated infrastructure put in place to serve one customer, Consumers would use its Contribution in Aid of Construction (CIAC) policy and other traditional cost allocation through the COSS.

Q. What current Consumers CIAC policies and charges would govern data centers?

A. Data centers would be governed by Consumers' rule C1.4 Extraordinary Facility Requirements and Charges, since they have capacity requirements above 1,000 kW.[78] C1.4 provides two options for customers to contribute to the Company's investment in building and maintaining extraordinary facilities required by the customer:[79]

1. Pay a monthly extraordinary facilities charge equal to 1.5% of the Company's total investment in such facilities.

[77] Ex, MEC-22, U21859-MNSC-CE-0034.

[78] *See also*, U21859-MNSC-CE-0031.

[79] C1.4 Extraordinary Facility Requirements and Charges. https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.pdf.

2. Make an upfront payment of the total estimated cost of construction minus a CIAC allowance based on the projected annual incremental load times a specified dollar per kWh or kW based on the rate schedule and contract duration.

Q. Do you have concerns with the use of CIAC allowances in C1.4 to collect the cost of distribution investments required by data center customers?

A. Yes. Consumers' general service CIAC allowances, which would apply to Rate GPD, may be based on a calculation that includes power supply revenues. To the extent that Consumers' CIAC allowances incorporate power supply revenue, the allowances are oversized and may not sufficiently collect the costs of distribution investments made for data center customers.

Q. Has there been discussion of the reasonableness of CIAC allowances for extraordinary facilities?

A. Yes. In U-20561, the Commission has previously "found it would benefit from additional information on whether the current CIAC policy fully reflects cost-of-service principles.[80] In U-20697, the Commission established a workgroup to discuss CIAC policies and tariffs.[81] The CIAC workgroup debated the appropriateness of including power supply revenue in CIAC allowances for customers requesting a large distribution line extension.[82] However, the CIAC workgroup did not reach definitive conclusions on this topic, and the report concludes by directing the issues back to rate cases for further consideration.

[80] Case No. U-20561, May 8, 2020, Order, p. 98.

[81] Case No. U-20697, Dec. 17, 2020, Order, p. 331-32.

[82] Ex MEC-23, Case No. U-20697, Jan. 15, 2022, Contribution in Aid of Construction Workgroup Report, p.9, 15.

Q. Has the Commission denied the inclusion of power supply revenues in facilities allowances for large customers in other cases?

A. Yes. In the Company's most recent rate case, U-21585, the Commission denied Consumers' proposal to add a facilities allowance to Rate LED, finding "the parties do not dispute that a facilities allowance for Rate LED should only consider distribution and system contribution revenues, not power supply revenues."[83] The Commission stated that "if the company believes it beneficial to provide a facilities allowance for Rate LED, Consumers should propose a facilities allowance that includes only distribution and system contribution revenues, not power supply revenues, and that is based on a limited term…"[84] While Rate LED and Rate GPD differ in some respects, the Commission's decision reinforces my concern about including power supply revenues in a facilities allowance for extraordinary distribution investments. The scale of data center investment necessitates an approach that will ensure those customers' responsibility for the investments made on their behalf.

Q. How should Consumers better reflect cost causation for the described distribution investments?

A. I recommend that Consumers directly assign any dedicated facilities costs to the data center customer without the opportunity to offset some or all of the upfront costs via a CIAC contract. Evergy Kansas recently proposed to update its line extension policies to ensure large customers requesting line extensions are responsible for all costs associated with any

[83] Case No. U-21585, March 21, 2025, Order, p. 424.

[84] *Id*. at 424-25.

dedicated facilities.[85] Specifically, Evergy updated its line extension policy to read "for extensions of transmission or substation facilities, any Customer requesting service with substation or transmission facilities shall pay all costs associated with such extensions."[86] Customers requesting service must complete payment or arrange installment payments before construction can commence.

Q. Does that complete your testimony?

A. Yes.

[85] Direct Testimony Bradley Lutz. February 11, 2025. Docket: 25-EKME-315-TAR. Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc. for Approval of Large Load Service Rate Plan and Associated Tariffs. p.56.

[86] These costs do not include any resulting Network Upgrade costs for facilities classified as transmission under the Southwest Power Pool Open Access Transmission Tariff. *See Id.* Exhibit DBL-1.

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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

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.

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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.

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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.

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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 June 2025

Question:

7. Please refer to the Direct Testimony of Laura M. Connolly, p. 8 lines 9-11 and specify whether any of the over 15 GW of prospective data center load would qualify as an enterprise data center under Public Act 207 of 2024, and if so, how much of the prospective data center load would qualify. Please also specify:

a. Whether the aggregate capital investment in any one of the potential data center facilities would be $250,000,000.00 or greater, and if so, what percentage of the prospective data center load is this true of.

b. Whether any of the prospective data center customers, along with their affiliates, would create and maintain a minimum of 30 new full-time jobs in Michigan with an annual wage that is equal to 150% or more of the prosperity region median wage through December 31, 2050, and if so, what percentage of the prospective data center load is this true of.

c. Whether any of the prospective data center facilities would be located on the property included in a brownfield plan under the brownfield redevelopment financing act or on property that was once an industrial site used primarily as a power plant to generate electricity for sale, and if so, what percentage of the prospective data center load is this true of.

d. For any of the potential data center facilities located on property described in Request 7(c), whether any of the prospective data center customers, along with their affiliates, would create and maintain a minimum of 30 new full-time jobs in Michigan with an annual wage that is equal to 150% or more of the prosperity region median wage through December 31, 2065, and if so, what percentage of the prospective data center load is this true of.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that said request is not relevant to a determination of reasonable modifications to the Company's Rate GPD tariff to allow for certain customer protections. The Company further objects to this request to the extent that it calls for a legal conclusion. Subject to this objection, and without waiving it, Consumers Energy responds as follows:

Qualification as an enterprise data center is determined by the Michigan Strategic Fund. The Company is not a party to that determination.

a. Most potential data center customers have not shared investment figures with the Company. Three requests have indicated capital investments above $250,000,000. U-21859-AG-CE-0015 Supplemental identified 15,849 MW of projects. The three requests totaled 945 MW or 5.96% of the total inquired MW shared investment figures above $250,000,000.
b. This information is not disclosed to the Company.

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c. The majority are not considering brownfield sites. One of the requests may qualify as a brownfield but more site information and due diligence would be needed to understand the brownfield status. U-21859-AG-CE-0015 Supplemental identified 15,849 MW of projects. The one potential brownfield site represented 200 MW or 1.26% of the total inquired MW. Consumers Energy does not know if potential data center customers are considering former generation plants.
d. This information is not disclosed to the Company.

Witness: Laura M. Connolly
Date: May 28, 2025

Question:

4. Please provide a list of all requests to serve new data center load the Company has received over the last 12 months, including for each data center:

a. Location of the proposed data center;

b. Requested contract demand;

c. Any contract language for each data center addressing the items described in sub-question 1-3.a-h above (including the entirety of contracts addressing these terms, to the extent they exist);

d. Any determinations the Company has made for financial security measures and any "ramp up period[s]" for such data centers, along with the analyses, studies, and calculations used in making those determinations (including such analyses, studies, and calculations for a data center even if a final determination has not yet been made); and

e. Analyses, studies, and calculations the Company has conducted concerning an assessment of potential stranded asset costs and cost shifting for the data center.

To the extent the Company might typically seek a Protective Order concerning material sought by this question and the other questions in this request, it is welcome to propose a draft of such a Protective Order for consideration.

Response:

a. The following chart sets forth the inquiries for potential service Consumers Energy has received in the last twelve months from potential data center customers. Note that these are inquiries, and do not represent commitments to take service from the Company. Please see attached.

Id	Location	Load (MW)
1	East Central region	300
2	East Central region	400
3	South Central region	1,000
4	East Central region	300
5	Unknown	300
6	East Central region	300
7	Unknown	200
8	Unknown	Unknown
9	Unknown	200
10	Unknown	250
11	Southeasterly region	Unknown
12	East Central region	200
13	East Central region	1,000
14	East Central region	2,100
15	Southwest region	500
16	West region	300
17	Unknown	300
18	Unknown	500
19	Unknown	420
20	East region	100
21	Unknown	300
22	East region	700
23	Unknown	1,000

Id	Location	Load (MW)
24	East Central region	300
25	Unknown	Unknown
26	Unknown	500
27	Unknown	Unknown
28	Unknown	60
29	South Central region	100
30	Unknown	70
31	Southwest region	Unknown
32	East region	500
33	Unknown	Unknown
34	South Central region	75
35	Southwest region	50
36	Southwest region	219
37	Unknown	Unknown
38	Unknown	1,200
39	Unknown	300
40	Southwest region	4
41	Unknown	300
42	Unknown	Unknown
43	Unknown	Unknown
44	Southeasterly region	100
45	Unknown	500
46	Southeasterly region	10

Id	Location	Load (MW)
47	East Central region	300
48	East Central region	1,000
49	Unknown	1,000
50	Unknown	500
51	Unknown	Unknown
52	Unknown	500
53	Unknown	500
54	Unknown	600
55	Southeasterly region	Unknown
56	Unknown	Unknown
57	Unknown	145
58	Unknown	1,000
59	East region	100
60	East Central region	250
61	Unknown	500
62	Southeasterly region	500
63	Unknown	200
64	Unknown	900
65	East Central region	Unknown
66	Northeast region	100
67	Unknown	300

b. See response to a.

c. See response to U21859-AG-CE-0014

d. Financial security has not been evaluated for all inquiries. The Company has evaluated the financial security of one customer based on their publicly available credit rating. No financial calculations or analysis was performed. As stated in U-21859-AG-CE-0064, the Company did not perform analysis using spreadsheets or formulas, as it reviewed publicly available credit and financial data regarding the customer. The Company does not make any determination or perform any analysis on ramp up periods but rather works with each potential customer to determine if the Company can meet their expected ramp up period.

e. The Company does not perform such a study for each inquiry. The Company has not performed any stranded costs studies. The Company has not evaluated the impact of cost shifting for any specific customer inquiry as the Company has not entered into any new contracts for data center customers to date.

Witness: Laura M. Connolly
Date: May 28, 2025

Question:

21859-DCC-CE-0020. Please refer to the Company's response to DCC-5 and DCC-6 (U21859-DCC-CE-0005 and 0006). Why did Consumers engage with the Transmission Owner to evaluate 2.65 GW of large load additions (as opposed to any other amount)?

Response:

The Company engaged with the Transmission Owner on 2.65 GW of large load additions based on advanced discussions with economic development and data center projects that are considered to be more probable prospects.

Witness: Laura M. Connolly
Date: May 13, 2025

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Question:

7. Provide Consumers' annual peak demand in each of the past 10 years.

Response:

Year	Month	MW	Day	Hour
2015	July	7231	28	16
2016	August	7635	11	15
2017	July	7057	19	16
2018	July	7568	5	16
2019	July	7476	19	16
2020	July	7675	9	14
2021	August	7370	24	16
2022	June	7528	21	18
2023	September	7518	5	16
2024	August	7472	26	16

Source:
MPSC P-521 Page 401

Witness: Laura M. Connolly
Date: June 10, 2025

Question:

16. Please explain Consumers' basis for proposing a load threshold of 100 MW (as opposed to a lower threshold) for the proposed Rate GPD data center provisions.

Response:

The tariff provisions proposed are intended to address the large hyper scale data centers and these tend to be around 100 MW or greater.

Witness: Laura M. Connolly
Date: April 30, 2025

Question:

5. Please refer to the Direct Testimony of Laura M. Connolly, p. 5 lines 10-12.

a. How many large-scale data centers would need to come online before Consumers would develop a rate specific to data centers?

b. What duration of load data from large-scale data centers would Consumers need in order to develop a rate specific to data centers?

c. Would it be feasible for Consumers to develop a rate specific to data centers before large-scale data centers come online? If not, identify and explain each reason why not.

Response:

a. The Company has not developed a target number of large-scale data center customers that would need to come online before developing a rate.

b. The Company typically uses three years of actual, historic load data in order to develop a load shape that can be used to develop cost allocations.

c. The Company could develop a rate without any actual load data, however that would require making assumptions about the prospective customer load profile to assign costs in the COSS.

Witness: Laura M. Connolly
Date: April 30, 2025

Question:

9. Please refer to Consumers' Application, para. 8, along with the testimony of Laura M. Connolly p. 6 lines 4-8, and explain how a 15-year minimum contract term reflects the term of power supply resources that include self-build resources with a 30 year or greater depreciation schedule and 15- to 25-year PPAs.

Response:

The 15-year minimum contract term was proposed to strike a balance between the life of the assets that may be procured to serve these customers, the life of the infrastructure the data center will put into place, while remaining competitive with other utility data center tariffs.

Witness: Laura M. Connolly
Date: April 30, 2025

Question:

21. Refer to Consumers' Application at para. 9, along with the Connolly Testimony at p. 6 lines 9-16.

a. Explain the basis for setting the Minimum Billing Demand at 80% of the Contract Capacity, rather than some other percentage. Produce any analysis, workpapers, or other documentation regarding the 80% Minimum Billing Demand.

b. Did Consumers assess the potential impact of a minimum billing demand other than 80%? If yes, provide the results of that assessment, along with any analysis, workpapers, or other documentation.

Response:

a. The Company set the Minimum Billing Demand at 80% based on benchmarking against other utility data center tariffs.

b. No.

Witness: Laura M. Connolly
Date: April 30, 2025

Question:

11. Please refer to Exhibit A-1 (LMC-1) page 3 (tariff Sheet No. D-67.10), stating "The Company may reduce the Exit Fee if it determines, in its sole discretion, that the loss of Customer's load will not harm the Company or its other customers." How will the Company determine that the loss of a data center customer's load will not harm the Company or its other customers?

Response:

The Company will review the requested load termination and determine if there is a new customer that could be served by the resources which were used to serve the exiting customer's load.

Witness: Laura M. Connolly
Date: May 30, 2025

Question:

10. Please refer to Consumers' Application, para. 10 and explain how Consumers would determine whether a requested reduction in contract capacity would create a stranded asset or otherwise shift costs to the Company or its other customers.

Response:

The Company will review the requested load reduction and determine if there is another customer that could be served by that load.

Witness: Laura M. Connolly
Date: April 30, 2025

Question:

10. Please refer to Consumers' Application, paragraph 13.

a. Did the Company consider applying an exit fee during the ramp up period? (For example, a graduated fee that increases at specified stages of the ramp-up period). If so, please explain in detail the basis for not including such a proposal in the proposed tariff revisions. If not, please explain why not.

b. If the data center customer does not originally take service at the distribution level, would the Company consider it eligible for the exit fee if it stops taking generation electric service?

c. Will the exit fee also include Rate GPD's System Access Charge and any applicable non-consumption based surcharges?

Response:

a. The Company believes the exit fee should apply during the ramp up period and will support clarifying that in the tariff language.

b. If the customer is taking service on the data center provision, they would be responsible for the exit fee requirements regardless of how they take service.

c. No.

Witness: Laura M. Connolly
Date: May 30, 2025

Question:

DCC-7. Please provide a description of the generation investment the Company believes would be required to serve approximately 15 GW of new peak load.

a. If the Company has evaluated the generation investment necessary to accommodate a different level of peak load increase, identify the specific load increase evaluated and provide a description of the generation investment the Company believes would be required to serve that level of peak load increase.

Response:

The Company has not evaluated generation investment required for 15 GW of additional peak load.

a. The Company has considered load growth scenarios and required generation supply for up to approximately 2 GW of new peak load. Generation investment requirements have not been identified for the load growth, in isolation. Instead, the Company adds load growth scenarios to existing or projected peak load requirements for the entirety of its service territory. Determination of generation investment required for projected peak load is done within the integrated resource plan process. Incremental generation investment would be identified in the Company's next IRP.

Witness: Laura M. Connolly
Date: April 16, 2025

Question:

17. Please identify each type of cost associated with building and interconnecting new energy resources to serve the new load associated with a new large load customer of 100 MW or larger.

a. For each type of cost, please identify if there is any circumstance under which the cost is directly assigned to the prospective customer.

b. Please describe and identify the range of total new energy resources costs for a prospective new customer load of 100 MW or larger.

Response:

a. The Company is not proposing to direct assign any costs to data centers but rather allocate them according to the requirements of MCL 460.11(1), which is how it treats other customers.

b. These costs are currently unknown and the range of costs depends on the specific mix of new resources required to serve the customer. The incremental (new) customer load will be included within the portfolio optimizations included in the IRP process.

Witness: Laura M. Connolly
Date: May 30, 2025

Question:

17. Please provide all analyses conducted by or at the direction of Consumers to analyze the potential impact(s) of data centers on:
a. Consumers' revenue;
b. Consumers' net income or profit;
c. Consumers' cost of service study results, including cost allocation to customer classes;
d. Cost-shifting or cross-subsidization among customer classes; and
e. Residential rate or bill impacts.

Response:

Objection of Counsel: **Consumers Energy Company objects to this discovery request to the extent it calls for privileged attorney client information created in anticipation of litigation. Consumers Energy further objects to the request to the extent that any evaluation contains unaggregated customer data that is subject to the Company's data privacy tariff.**

a. The Company has not performed this analysis.

b. The Company has not performed this analysis.

c. Consumers Energy is unable to provide this analysis as it was developed at the request of counsel in anticipation of this litigation and contains unaggregated customer data. The Company can provide the attached cost of service model which allows the intervenor to input their own cost and load assumptions to calculate the impacts of increased data center load. This is provided subject to the entry of a confidentiality agreement with the Company or a protective order due to the LTILRR data. Load data assumptions for data centers can be entered into the highlighted yellow section of the Input 4 Load Data and TY Sales tab. Any cost assumption changes can be entered in the appropriate category in the Input 1 tab. These changes will then flow through the model and you can view impacts on the EAD-6 Part 1 tab. The Company will walk intervening parties through this model at their request and will provide a later response with a hypothetical, discussing where the assumptions are coming from, that is representative as to how the Company is looking at new data center customers. The model has been updated to provide analysis based on a hypothetical 500 MW, 100% load factor customer. The costs have been updated based on a 500 MW PPA using publicly available data from NREL. The load shape was estimated assuming a 500 MW using the same energy for all hours of the year.

d. See response to c.

e. See response to c.

Witness: Laura M. Connolly
Date: June 6, 2025

Question:

4. Refer to U21859-MNSC-CE-0035, estimating a range of $46.5M to $96M total costs for interconnection facilities for a new 100 MW load.

a. Please provide an explanation of the basis for the Company's estimated range of $46.5M to $96M total costs for interconnection facilities for a new 100 MW load.

b. In live, unlocked Excel file format with all links and formula intact, provide all workpapers and calculations underlying the estimated range.

c. To the extent that the estimated range includes both transmission and distribution costs, please specify separate ranges for transmission and distribution costs.

Response:

a. For the Distribution asset estimates, the Company took 5 typical projects (this excluded projects that had unique aspects that would falsely inflate the average of a typical project) and determined the average cost per transformer. The Company then took this average and calculated the number of transformers required at each voltage to serve 100 MWs. The rounded result became the average high and low range for distribution cost.

   Estimates for transmission facilities required to interconnect a new 100 MW load utilized transmission cost estimates provided by the impacted Transmission Owner(s) for recent ~100 MW projects in the Company's service territory. 2 projects fell within range of the 100 MW size requested. A third project, representing a smaller load addition, was also included in the cluster to present a potential low-end transmission interconnection facility requirement assuming existing transmission infrastructure could reliably handle 100 MW of additional load.

b. See attached file.

c. The estimated range for distribution upgrades excluding outliers used was $28.0 Million - $34.0 Million. The estimated range for Transmission upgrades used was $18.5 Million - $62.0 Million. For a total average range of $46.5 Million - $96 Million.

   As noted in the response to U21859-MNSC-CE-0035, interconnection facilities for a 100 MW load can vary greatly based on location and network upgrades required to adequately interconnect the load while maintaining system reliability.

Witness: Laura M. Connolly
Date: June 10, 2025

Question:

18. Please identify each type of cost associated with interconnecting a new large load customer of 100 MW or larger. For each type of cost, please identify whether it is directly assigned to the prospective customer load.

Response:

Cost associated with interconnecting a new large load customer of 100 MW or greater includes Transmission and Distribution costs.

Transmission costs could include, but are not limited to, new transmission lines built between the existing transmission facilities and the location of the new load, new transmission switching station(s) at the site of the load or elsewhere, transmission network upgrades such as reconductoring of transmission lines, substation equipment replacement, system protection relaying upgrades, line or substation facilities to increase transmission capacity for the new load addition, and/or line routing and easement acquisition. The transmission costs listed are for interconnection costs of load and do not include additional transmission costs to interconnect new energy resources to serve the load.

Distribution costs could include, but are not limited to, new distribution lines built between existing or new transmission facilities and the new dedicated customer substation, distribution switching station(s), dedicated customer substation(s), line routing and easement acquisition, and/or power factor correction equipment depending on the customer’s power factor.

Supply resource costs are not included in these types of costs, as those are associated with serving new load not interconnection costs. Feasibility studies, customer meetings, contract negotiations, etc. are not considered in this response because they could be incurred with or without interconnecting new load.

The Company does not currently direct assign costs to specific customers but rather allocates costs in accordance with the requirements set forth in 2008 PA 286.

Witness: Laura M. Connolly
Date: April 30, 2025

Contribution in Aid of Construction Workgroup Report

MPSC Case No. U-20697

January 15, 2022

Dan Scripps, Chair
Tremaine Phillips, Commissioner
Katherine Peretick, Commissioner

Contents

Executive Summary

On December 17, 2020 the Michigan Public Service Commission (MPSC) directed MPSC Staff (Staff) to convene a workgroup to address the Contribution in Aid of Construction (CIAC) policy of Consumers Energy Company (Consumers).[1] This direction was in response to the MEC Coalition's[2] analysis of and recommendations for CIAC policies in Consumers' general rate case.[3] According to the MEC Coalition, Consumers' existing CIAC policy predated unbundled ratemaking and created subsidies between customer classes. Rather than require Consumers to implement the MEC Coalition's recommendations in the Company's next rate case, the Commission ordered Staff to "establish a framework for participation and a conference schedule; and, in collaboration with participants, a list of topics, issues, and objectives to be addressed and achieved." Following the conclusion of the workgroup, Staff was required to file a report "detailing its findings and recommendations regarding any recommended changes to the Commission's CIAC policies that can be considered in future rate case." This report will present the CIAC workgroup's activities including a summary of its three conferences, an overview of the discussions held during those conferences, and the joint recommendations of the workgroup.

This report is organized as follows:

1. Introduction to the Commission's recent orders on CIAC policy
2. Overview of the workgroup's meetings
3. Details of MEC Coalition's analysis and proposal for CIAC policies
4. Discussion topics explored by the workgroup and ongoing issues with CIAC policies
5. Recommendations

The key findings of this report are: CIAC policy is a complex issue that directly affects new and existing utility customers, the workgroup was unable to reach consensus on which revenues to use in setting CIAC policy, the workgroup sees benefit in continuing to meet for further discussion on more specific CIAC topics, and CIAC reform should only take place in general rate cases**.** Staff is grateful for the generous participation of all workgroup members.

[1] December 17, 2020 Order in MPSC Case No. U-20697, p 330-331.
[2] The MEC Coalition is made up of the Natural Resources Defense Council, Sierra Club, and Citizens Utility Board.
[3] MPSC Case No. U-20697.

Introduction

CIAC policies are those that require a customer requesting a new connection to an electric distribution utility's system to pay a refundable deposit for a portion of the costs associated with the new connection or line extension. Should other new customers attach to the system extension partially paid for by the original customer's deposit, that original customer will receive a refund as prescribed in the utility's tariff.

Typically, a general service customer requesting a line extension for less than 1,000 kW of load must pay the difference between the cost of the connection and the expected total revenue generated by the customer over a period of time, such as 2 years. Commercial and industrial (C&I) customers over 1,000 kW are afforded an allowance set by a standard table, which varies by the number of full service contract years, including for customers without a full service contract.

A deposit by residential customers is usually required for extensions beyond an initial allowance (e.g., 600 feet) at a flat cost per foot of additional distribution extension. The deposit may be offset by a refund if additional customers attach to the original customer's extension at a later date. The allowances, length of revenue generation offset, price per foot of extension, deposit refund conditions, and special considerations for underground extensions are codified in the utility's CIAC tariff. New customers create new costs for their connection, but they also create new revenue for the utility to offset costs beyond the connection project timeline. These CIAC policies are intended to balance the cost associated with new customer connections between those individual customers and the existing rate base at large, while allowing an affordable way for customers to join the system.

Distribution line extensions requiring CIAC via customer deposits are not to be confused with the service line extension to the customer's building. Service lines begin at the nearest utility pole and terminate at the Customer's meter. Every customer requires a service line whereas a customer may not require a distribution line extension (i.e., zero foot extension) if there is already a utility pole near enough for connection.

Consumers filed a general rate case in February 2020. The MEC Coalition intervened in the case and proposed changes to existing CIAC policy to be included in the utility's following rate case. Consumers recommended that any changes to CIAC policy should be withheld until a future case or proceeding due to the complexity of the issues at stake. The Commission agreed with the administrative law judge's opinion that a workgroup should be convened to discuss such issues but did not agree that updated CIAC tariffs should be included in Consumers' next rate case.

The Commission directed Staff to convene the CIAC workgroup in 2021 to consider updates to CIAC policies. Staff was required to provide notice of the workgroup, create a framework for participation, and create a list of topics, issues, and objectives in collaboration with workgroup participants. This report, as ordered by the Commission, provides the input of the parties and recommendations of the workgroup's effort for use in future rate cases.

Prior to the Consumers case, for which the CIAC workgroup was created, the MEC Coalition made a substantially similar proposal in DTE Electric Company's (DTE's) general rate case. The Commission's final order in the DTE case was issued on May 8, 2020[4] and differed from its later order in the Consumers case by directing DTE in its next case to: "(1) provide supplementary, substantial, and specific support of the current CIAC model, (2) demonstrate that the current CIAC model is cost-of-service based, (3) provide evidence specifically showing how the overall revenues from new customer connections help offset other customer costs, and (4) provide details regarding how new customer connections drive upgrades to the system that may benefit other customers."[5] While the Commission ordered a different approach for the two largest electric utilities in the state, Staff invited and received participation by both companies in the CIAC workgroup formed from the Consumers case order.

The MEC Coalition presented analysis which examined the payback periods for new customer attachments and compared those periods between customer class in both the Consumers and DTE cases, assuming that only distribution plant revenues should be considered in the payback period calculation. In both cases the MEC Coalition asserted that residential customers generated additional revenue to offset their line extension costs faster than larger general service customers, implying a subsidy was taking place under existing CIAC policies. To correct for the alleged subsidy, the MEC Coalition proposed to standardize the payback period for line extensions across customer classes. In the DTE case, the Commission found the MEC Coalition's proposal to be unsupported but requested that DTE provide evidence to support its existing CIAC policy. In the Consumers case, the Commission demurred that the issues were complex and required additional study.

Neither utility was required to adjust tariffs or propose new CIAC policy in subsequent cases. However, it is clear that the Commission is interested in further study of CIAC policy issues as evidenced by the request for support in DTE's case and the creation of the workgroup in Consumers' case. This report provides details on the MEC Coalition's analysis and proposal as well as the discussion and findings of the CIAC workgroup for the Commission's consideration in following cases. Because the workgroup was created in response to the MEC Coalition's proposal in the Consumers case this report will focus at times on the particulars of that utility, but the discussion and some recommendations may still apply to DTE and other utilities' CIAC policies.

The analysis and discussion presented in this report does not bind any of the participating parties to a particular CIAC policy recommendation unless expressed otherwise in a formal

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[4] The final order in the DTE case was issued between the filing of the Consumers case and the MEC Coalition's similar proposal in the Consumers case.
[5] May 8, 2020 Order in MPSC Case No. U-20561, p 98.

proceeding before the Commission. While the process was instructive for the workgroup members, it should not constrain any future proposals for any reason.

Workgroup Meetings

Staff notified parties to the Consumers case of the formation of the CIAC workgroup and held meetings on August 24, September 21, and October 15, 2021. The Association of Businesses Advocating Tariff Equity (ABATE), Consumers, DTE, the MEC Coalition, and Staff all participated in the workgroup meetings. While the workgroup was created in response to the Commission order in the Consumers case, DTE was invited to and participated in the meetings in anticipation of CIAC issues being addressed in its next rate case.

The first meeting included a presentation by 5 Lakes Energy on behalf of the MEC Coalition to review its CIAC analysis and proposal made in the 2020 Consumers case with an update to the model with data from Consumers current on-going general rate case[6]. Further details of the MEC Coalition's presentation will be addressed in the next section of this report. Staff led an open-ended discussion following the MEC Coalition's presentation and debuted a list of topics, issues, and objectives to the workgroup. As a result of the workgroup's discussion, Consumers agreed to present a review of its CIAC policy at the next meeting. Staff explained its intention for the workgroup's ultimate report to the Commission and the format for future workgroup meetings.

The second meeting consisted of separate presentations by DTE and Consumers regarding each utility's CIAC policy along with examples of how a customer would engage with the utility during the line extension process. The presentations generally supported the utilities' current CIAC policies. Following the presentations, another free-flowing discussion ensued which expanded on issues brought up in the first meeting and from the utilities' presentations.

Staff reserved the third meeting of the workgroup to present its draft report and discuss initial recommendations. The workgroup discussed lingering issues from the previous meetings and narrowed the scope for its recommendations to the Commission. Following the third meeting Staff continued to develop the workgroup's report and recommendations and engaged with stakeholders on the report's contents throughout the early winter of 2021.

MEC Analysis and Proposal

In direct testimony on behalf of the MEC Coalition in the 2020 Consumers general rate case Robert Ozar of 5 Lakes Energy sponsored and discussed the CIAC analysis and proposal that

[6] MPSC Case No. U-20987.

spurred the CIAC workgroup's efforts in 2021.[7] Mr. Ozar reproduced his analysis for the CIAC workgroup using updated data from the current Consumers rate case. His analysis relies on the idea that Consumers' current CIAC policy predates unbundled rate making (i.e., the division of rates between power supply and delivery to accommodate customer choice in energy provider). When the utility was vertically integrated, a customer's total revenue could be assumed to offset all costs associated with being served by the utility's generation, transmission, and distribution systems. For this reason, the CIAC policy for general service customers provides an allowance for three times the customer's expected *total* annual revenue.[8] The MEC Coalition argued that since the advent of unbundled electric service, the actual offset to extension cost made by the customer is to the distribution capital revenue requirement. According to the MEC Coalition, applying an allowance of a new customer's total revenue over three years for what the MEC Coalition argues is only a distribution capital investment thus creates a mismatch. Further, according to the MEC Coalition, only a portion of total distribution revenue can be said to apply to the distribution capital revenue requirement. In other words, they claim that only a portion of a customer's total bill going forward will end up contributing to the new connection to the distribution system.

The MEC Coalition opined that the aforementioned balancing act of CIAC policy – between the additional costs a new customer creates versus their continued contribution to the distribution system—no longer holds under Mr. Ozar's analysis. Because only a part of the customer's total revenue over 3 years will pay for the utility's upfront contribution toward the new line extension under their assumption, it thus takes longer for the customer to "pay it off" through base rates than the tariff assumes. Fundamentally, the MEC Coalition argued that it takes much longer for this to occur for a general service customer than it does for a residential customer because the power supply revenues from general service customers are a larger percentage of total revenues. In order to quantify the purported difference in payback periods among customer classes, Mr. Ozar calculated how long it would take a customer in each class to repay the Company's CIAC allowance using only the portion of revenue associated with distribution capital. The CIAC allowances for some rates had to be calculated differently because of the different CIAC policies offered to residential and general service customers (e.g., 600 foot allowance for residential overhead lines versus 3 years of total revenue for general service.) Mr. Ozar found that when applying only the distribution capital portion of customer revenue to the appropriate allowances, it took 4.9 years for an overhead-line-serviced residential customer to pay back their allowance and between 26.9 and 140.2 years for a General Primary Demand (GPD) customer, voltage level 3 and 1 respectively. This is because a relatively smaller portion of GPD customers' overall bills is revenue associated with distribution capital. Based on this analysis, Mr. Ozar concluded that

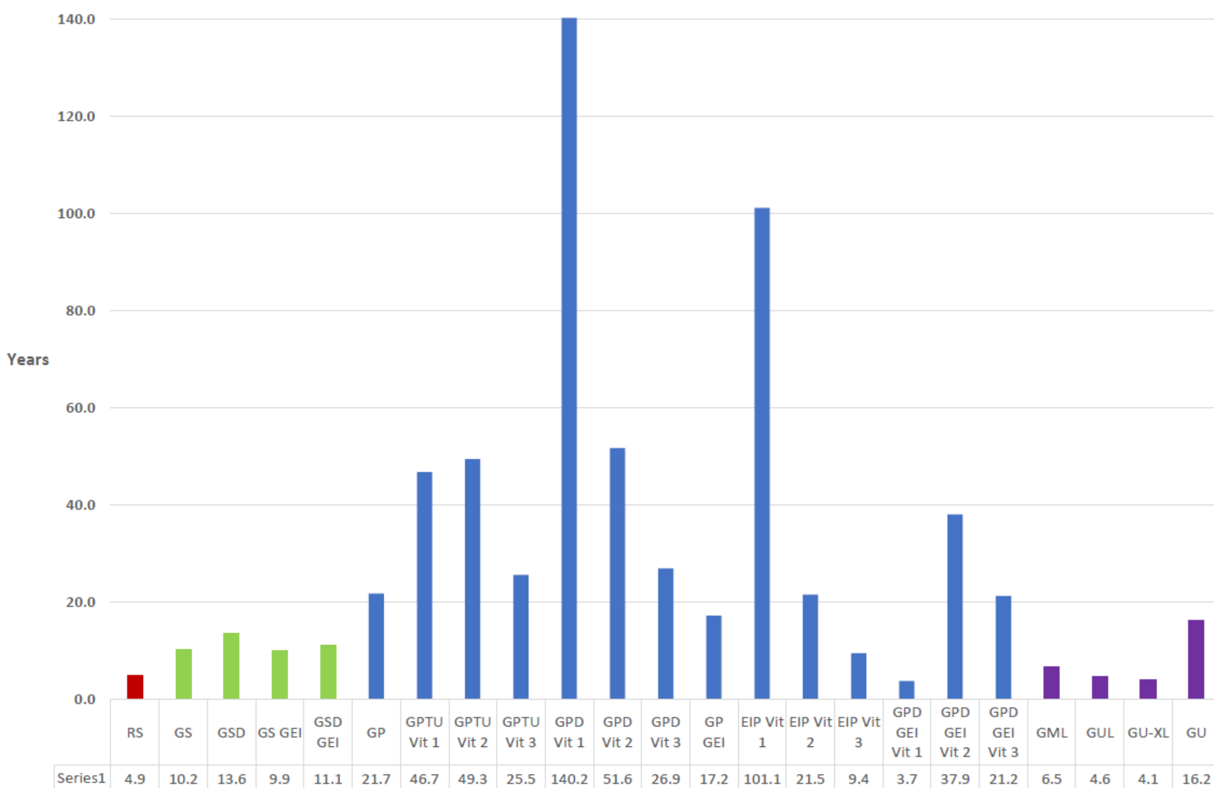
[7] For an in depth explanation of the MEC Coalition's analysis see Mr. Ozar's testimony in Case U-20697.

[8] The tariff provides adjustments for differences between expected and actual revenues and refunds for additional customers connecting to the new service extension. See Sheet No. C-27.00 in the Consumers rate book for details.

Consumers current CIAC policy creates a subsidy between customer classes, because general service customers are allowed such a long time to achieve parity with the rest of customers contributing to distribution rate base compared to residential customers, who do so much more quickly, since a larger portion of their overall bills is associate with distribution capital costs.

Figure 1

Payback Times for Distribution Systems Additions Under Current CIAC Rule



MEC Coalition Presentation to CIAC Workgroup 9/24/2021

To remedy the alleged disparity among classes, Mr. Ozar calculated a uniform payback period for line extensions by taking the reciprocal of the economic carrying cost of total electric distribution capital investment, or the electric distribution rate base divided by the capital portion of distribution revenue requirement (i.e., total distribution capital divided by total annual revenues associated with paying for that capital). This resulted in a system-wide average of 7.42 years, or the time it takes for distribution revenue alone to pay for distribution capital costs. In order to apply this uniform payback period to each rate schedule individually, Mr. Ozar then multiplied the 7.42 years times the capital-related portion of each distribution rate. This is akin to creating any other type of rate, where required revenue is divided by sales to reach a $/kWh rate, but in this case the required revenue is the capital-related portion of distribution revenue, which is then multiplied by 7.42. Thus, an individual customer would receive an allowance of the newly calculated credit rate times their estimated annual energy usage.

Figure 2

MEC Coalition CIAC Reform-Utility Contribution

Rate Schedule	Credit $/kwh
RS	0.40710
GS	0.33805
GSD	0.20860
GS GEI	0.34951
GSD GEI	0.26817
GP	0.11019
GPTU Vit 1	0.03847
GPTU Vit 2	0.03790
GPTU Vit 3	0.08567
GPD Vit 1	0.00850
GPD Vit 2	0.03358
GPD Vit 3	0.07995
GP GEI	0.14731
EIP Vit 1	0.01240
EIP Vit 2	0.06460
EIP Vit 3	0.19592
GPD GEI Vit 1	0.02319
GPD GEI Vit 2	0.05996
GPD GEI Vit 3	0.11450
GML	0.40225
GUL	1.31620
GU-XL	3.04535
GU	0.13424

Applied to estimated annual usage (kWh)

While the rates differ for every customer type, they are all based on the same 7.42 years Mr. Ozar believes it takes for all customers' collective distribution revenues to pay off distribution capital. Alternatively, a footage allowance could be calculated using the MEC Coalition's proposal by multiplying the per kWh residential allowance by the class average sales per customer then divided by an updated cost-per-foot of line extension (See Appendix A for MEC Coalition's complete presentation.)

Under this scheme, Mr. Ozar calculated that the average residential customer's allowance would be reduced from $4,250 to $3,157, and general service customers would also see a decrease in CIAC allowance. The ultimate beneficiaries would be the existing Consumers customers who, after CIAC reform, would pay less through base rates to cover the cost to extend service to new customers. It may be counterintuitive to see the residential allowance decrease when attempting to resolve the alleged subsidy between residential and general service customers, however, the reduction in CIAC allowance, under the uniform payback approach is larger for general service customers. That is because the solution also affects the alleged subsidy between existing customers currently paying base rates and the new customers receiving a line extension.

The MEC Coalition's analysis can be affected by a number of assumptions, chiefly, 1) the assumption that only distribution capital-related revenues should be recognized in the analysis, and 2) the cost per foot of residential distribution line extension. The analysis in the Consumers rate case relied on the $3.5 per foot cost for additional line extension beyond the 600 foot allowance for residential customers as the actual cost for distribution investment in line extension. In the workgroup presentation, Mr. Ozar accounted for this assumption by providing a chart showing how different costs per foot of line extensions affects the residential allowance. The greater the cost per foot of extension the less footage would be included in the allowance. The primary cause of reduction in length of residential extension allowance is related to the out-of-date per foot cost in the tariff. As will be discussed, parties disagree on the validity of the assumption that only distribution capital-related revenues should be recognized.

The CIAC policy reform proposed by the MEC Coalition would be included as a table in Consumers' line extension tariff and be updated in general rate case proceedings with newly approved cost data.

Discussion

The MEC Coalition's analysis and proposal spurred a great deal of discussion among the workgroup members. Utility, Staff, MEC, and ABATE experts engaged in debate on the assumptions, outcomes, and merits of the work presented by the MEC Coalition as well as purpose and nature of CIAC policy in general. This section of the report represents the continuation of the analysis of CIAC policy and will provide the Commission with further investigation into the ideas and implications raised by the workgroup. The final section of this report will be the synthesis of that investigation via the workgroup's recommendations.

How much power supply revenue should be included in deposits, or should only distribution capital be used to determine the deposit amount?

Perhaps the most discussed topic of the workgroup meetings was on whether it is appropriate to consider only distribution capital investment and revenues in the MEC Coalition's analysis. On its face, it seems reasonable to conclude that a line extension only affects the cost of the distribution system, since the line extensions are physical infrastructure installed to deliver electricity to the new connections. However, the new load connected to the utility's distribution system still needs to receive power from somewhere. While the new customer necessarily requires more wires to join the system, they are also providing additional revenue for power supply, if they are a full service customer. This incremental revenue may be more difficult to discern. During the workgroup discussion, it was clear that some parties believe that a portion of power supply revenue could be attributed to offsetting the line extension, since the utility receives incremental revenue from supply as well. Like in so many other facets of utility regulation that "some portion" can be difficult to define.

ABATE argued that when considering the policy in the context of whether a customer chooses to locate in the territory or not, the incremental margin of revenues over fixed costs, inclusive of both supply and delivery, will benefit all customers, as it will contribute to virtually any rate base item on which the utility receives a return.

DTE presented its current CIAC policy to the workgroup during the second meeting. The tariff for this policy provides a standard allowance table for customers requesting a line extension with a load greater than 1,000 kW. This table offers different allowances for customers choosing full service contracts and no full service contracts, with full service contract customer allowances varying by the number of years on such contracts. Customers requesting a line extension without a full service contract receive a smaller allowance because they will not produce power supply revenues to offset any marginal increase in power supply cost. This solution neatly addresses the issue about whether total revenue or only distribution revenue should be considered in CIAC policy because it treats the two services differently. Arguments can still be made about how much power supply revenue is reasonably necessary to offset the increase in costs related to the customer's new load. However, it is assumed by some that non-power-supply customers would not contribute to any marginal power supply costs; so they should not receive an allowance for that missing revenue. In theory, this method could be applied to residential customers as well, because they too can participate in customer choice of power supply. However, practically speaking, distinguishing between full service and choice customers is unhelpful because of the enrollment cap in customer choice. What DTE's CIAC tariff does is explicitly consider that for power supply customers some costs associated with line extension is related to power supply.

The question remains: if power supply revenue should be considered to offset incremental power supply costs for new load, then how much? Consumers' general service CIAC policy lies on one end of the spectrum where total power supply revenue for three years is implicitly assumed fully available to pay for the incremental increase in distribution cost (i.e., the distribution line extension). The MEC Coalition's CIAC reform policy is situated at the opposite end of that spectrum where the utility's contribution toward the line extension is made only through recognition of the customer's future distribution revenue and there is no assumed offset for power supply. This issue begs another question: how much incremental pressure does one customer's newly connected load put on power supply? If the utility has sufficient capacity in its power supply to accommodate the single source of new load, then the pressure (i.e., added cost) is zero. If that single customer's new load happens to be at the margin that requires the utility to expand its power supply, then the pressure, and thus cost, is significant.[9] As is often the case with issues of marginal power supply, the costs can be said to be zero until they aren't. Depending on the specific circumstances of the issue sometimes an analyst will rely on some form of market prices to determine marginal power supply costs or perhaps assume the most common method a utility may use to increase its power supply to meet new load (e.g., 75% of cost of new entry.)

In summary, ABATE, Consumers, and DTE all agreed that power supply revenue should be included in the offset for CIAC for full service customers. MEC advocated for its proposal to only rely on distribution capital-related revenue to determine line extension deposits, as discussed in the third section of this report. DTE made a further distinction that power supply fuel revenues should not be included in full-service revenues for the purpose of CIAC. Staff did not take a position on changes to CIAC policy in either the recent Consumers or DTE cases wherein MEC made its reform proposals and remains skeptical on this specific issue of what revenues to include in line extension deposits. The workgroup did not arrive at a consensus on this topic, but its contemplation led to the other issues discussed herein.

[9] This is the same inter-generational equity issue that has existed for decades for rates in general. Some might ask, "Why should legacy customers have to pay for new facilities (generation or delivery), if they've already paid for facilities sufficient to meet their needs?". But that is not how traditional rate setting works; rates have been set treating customers of all durations the same for decades.

Updating current line extension cost per foot

The actual cost per foot of line extension and how it differs from the tariff was raised several times during workgroup discussion. The Consumers tariff still shows a cost per additional foot of line extension beyond the 600 foot allowance for residential customer of $3.50. In contrast, DTE's residential line extension tariff charges $6.50 per foot beyond 600. Consumers did not contend that $3.50 was the actual current cost per foot for additional overhead distribution line. It was clear that the figure used in the tariff was many years old but Consumers was willing to explore reexamining the excess line extension charge for residential customer deposits. According to Consumers, 25-30% of complaints to the MPSC are about costs being too high for new construction.

To further complicate things it would be difficult to determine an exact per foot cost for line extension that would be applicable to all projects. For example, one line extension project could require more utility poles than another project of equal length. In this case the project with more poles would have a higher cost per foot for the extension. This also begs the question: if actual costs per foot of line extension is higher than the tariff, then should the cost for additional foot of extension be increased or should the allowance for footage be decreased? One could also consider the $3.50 per foot of additional line extension as a "charge" rather than the utility's direct cost being passed through to the customer. Should this be the case then that "charge" would still need to be linked to a cost, or net-cost, in some fashion in order to keep rates cost-based. Upon further investigation, the Commission could determine that the charge per additional foot of line extension should be made up of the combination of actual cost of the physical infrastructure being built less some amount representative of the benefit of additional load. Taking it one step further, should a line extension allowance and/or charge consider whether the new customer is a distributed generation customer? This is all to say that while it may be tempting to include an actual cost estimate per foot for extending service, there are other ways to incorporate the actual costs into CIAC allowances and charges. Updating the cost per foot in the tariff could also create a higher barrier for new customers to attach to the distribution system. Discouraging new load on the system through more onerous CIAC policy will negatively impact existing customers as well, assuming the new load contributes revenues above variable costs and thereby provides a contribution to fixed costs, enjoyed by all other customers. If one considers the role of the new customer after they have provided incremental revenues sufficient to cover their CIAC credit amount, then all future revenue from the customer can be said to help offset the rates of all other customers. When allocating costs and designing rates, the more customers and load available over which to spread those costs relieves the burden on the individual customer. Any utility would prefer to sell more of its product to more customers, and in the long-run existing customers benefit from load growth, so long as the cost of that growth is lower than the long-run benefits.

It could be beneficial to match actual costs of line extension more closely with CIAC charges over the standard allowance, but it must be weighed against the benefit to existing customers. As shown in Mr. Ozar's analysis the cost of the line extension could have a direct impact on the allowance for residential customers.

Whether or not the Commission approves a change to the residential line extension cost per foot in the utilities' tariffs, the allowance for C&I customers need not be changed. There is no specific cost per foot of line extension printed in the tariff for these customers. Instead, the allowance is dependent on the customer's revenue, with contractual assurance that the revenue target is actually met. For example, for C&I customers with load greater than 1,000 kW, the customer's CIAC allowance is set based on a standard allowance table, as shown below from DTE's rate book[10]:

Figure 3

DTE Electric CIAC Standard Allowance Table

Rate Schedule	Full Service Contract Term, Years					No Full Service Contract
	1	2	3	4	5	
D11, D10, D3	*$120* / kW	*$230* / kW	*$330* / kW	*$430* / kW	*$520*/ kW	*$95* / kW
D6.2	*$120* / kW	*$230* / kW	*$335* / kW	*$435* / kW	*$525*/ kW	*$95* / kW
D8, R1.1, R1.2, D3.3	*$90* / kW	*$170*/ kW	*$245* / kW	*$320* / kW	*$385*/ kW	*$95* / kW
R10	*$40* / kW	*$75* / kW	*$110*/ kW	*$145* / kW	*$175* / kW	*$95* / kW
D4	*$245* / kW	*$480* / kW	*$695* / kW	*$895* kW	*$1,085* / kW	*$95* / kW

Section C6.2(4)(a), Sheet No. C-30.00, based on anticipated average maximum demand

For these larger customer extensions current CIAC policy fixes the allowance based on full service contract year terms and charges the customer with the total cost of the extension beyond that allowance. This is contrasted by residential CIAC policy which sets prices and the allowance based on footage alone. For residential customer footage is a proxy for total line extension cost for rather than passing the actual cost through to the customer less an allowance like for C&I customers. The shortcoming of CIAC policy for residential compared to C&I customers is that the actual cost (i.e., total cost less allowance) of the line extension is not specifically borne by the customer. Therefore, updating the per foot line extension cost for residential customers may bring customer classes closer to parity in CIAC policy.

[10] Consumers has a similar table in section C1.4 (Sheet No. C-4.00) of its rate book, but allowances are calculated on anticipated energy rather than demand.

Determining footage allowance

Similar to the discussion on updating the cost for additional line extension footage in the tariff is how to set the free footage allowance. Both Consumers and DTE offer residential customers the first 600 feet of line extension free of charge. It came to light through discussion with the workgroup that this figure is not based on any specific calculation, but that most new individual customers fall below that threshold. In theory, if the typical customer requires 600 or fewer feet of line extension, and they only require about 4 years of distribution revenue to repay that allowance, that customer will quickly join the pool of customers contributing revenues above incremental costs. If another customer requires a longer line extension, then it stands that they will take longer for them to provide revenues above incremental costs. More data would be necessary to determine how much more costly it is to extend service to customer beyond 600 feet, and whether that cost increases linearly.

Determining the appropriate footage allowance could also run afoul of a basic tenet of electric rate design: calculating rates based on the cost of serving the *average* customer. If 600 feet were found to be the amount of line extension under which most new customers fell, then it ignores the amount of distribution line needed to serve the average customer. If the average customer only required a 200 foot extension, then at what length beyond that average is it appropriate to begin charging customers a deposit? Again, more analysis is necessary to confirm or evaluate this question, and particularly analysis showing whether or not the cost of a line extension increases linearly, or by some more complex function. This complex function could include the problem of how many utility poles are necessary for any given distance of line extension. For example, the cost per foot may be flat up until the next pole is required, at which point the flat cost ratchets up.

Customer deposits for line extensions can also be viewed as a transfer of risk from the utility to the customer requesting an attachment. A customer requiring a short extension of the distribution system is relatively low-risk to add compared to a similar customer much further away. If it is riskier to extend the system beyond 600 feet because costs increase beyond that distance or there are greater hazards in construction, then requiring a deposit would offset that risk.

During the second workgroup meeting, Staff posited a potential solution to updating costs and line extension footage allowances. Using a minimum system study, an analyst could determine the minimum amount of distribution line necessary to reach any customer on a utility's system. [That analysis differs from the traditional "minimum system study," which considers the zero load cost of connecting customers to the system.] That minimum would then be the standard allowance in footage or cost, with all excess cost to be recovered through the customer's deposit. The problem with this hypothesis is that the length of distribution system needed to attach the nearest customer could be zero. Such an analysis would require a number of assumptions, which would themselves inspire further debate. Another method suggested by Staff would be to calculate system-wide average or customer class average of distribution line footage per customer. That average could then be used as the CIAC allowance, with all excess extension costs to be included in the deposit.

While Consumers believes that the currently approved residential footage allowance of 600 feet is ideal, because it represents the average line extension necessary for residential customers (not including zero foot extensions) and adjusting the residential footage allowance could significantly impact the cost to customers for attachment to Consumers' system, the company is still open to exploring the topic further. Likewise, DTE is open to exploring the topic further.

Like with any theoretical cost allocation question, a trade off must be considered between burdening the existing customer, the new customer, the average customer, the outlier customer, and the vulnerable customer. Determining the charge for additional line extension and the standard allowance for the extension must also consider this trade off.

Effects of changing CIAC policy on revenue requirement

Beyond its effect on individual customers requesting a line extension, CIAC policy also affects the utility's revenue requirement. Changing CIAC policy such that it requires larger customer deposits, as the MEC Coalition's proposal would, reduces the utility's capital spending and thus its revenue requirement. If the new customer or load continues to be a going concern that contributes to the utility's revenue longer than the time it takes to recoup the initial outlay for line extension, then both the utility's shareholders and customers come out ahead. Shareholders will enjoy the return on increased capital spending and the customer base will enjoy another member to which costs can be spread. One potential pitfall of CIAC policy occurs when the customer at the end of the new line extension discontinues their service before their revenue can fully offset the extension costs. Requiring a customer deposit alleviates this concern somewhat.

It would also be difficult to determine if and when a line extension becomes no longer used and useful because at any time a new customer could come along and take advantage of the line extension. Again, this issue requires a delicate balancing act on the part of CIAC policy: how does the Commission balance the need of new connections to the system with those already connected? Extending distribution infrastructure without attachable customers would be a waste for current ratepayers, but the argument can be made that *eventually* there will be more customers to attach. Though the reasonableness of that argument must be evaluated carefully.

Further, the impact on revenue requirement from changes in CIAC policy for one customer class may affect all classes. In electric cost of service studies customer deposits for line extension are part of working capital and allocated to customers on revenue. For example, if CIAC policy reform arises from this report that would increase residential customer deposits then the corresponding revenue requirement reduction would be spread to all customers and not just the residential class.

The impact of CIAC policy on a utility's revenue requirement can be substantial. According to its workgroup presentation Consumers spends about $14M to connect new residential customers per year. Overall spending on new business, including line extension, can make up a significant portion of any utility's rate case request, and adjusting something as innocuous as the CIAC policy can eventually flow through rate case models and have a material impact on rates. This fact supports the workgroup's recommendation that the Commission consider implementing changes to CIAC policy only in general rate case proceedings, where the effects of those changes can be observed directly. A standalone proceeding or workgroup such as the one creating this report can provide insight to future Commission decisions, but any actual change in CIAC policy or tariffs should occur as part of a comprehensive rate proceeding.

Extraordinary facilities exemption

In the meeting, ABATE indicated that large customers for whom significant investments are made to connect them, are subject to minimum charges that help ensure that they provide revenues sufficient to cover the costs. Although they may exist to help ensure payment for extraordinary distribution costs, such minimum charges are based on demand charges that include power supply costs. ABATE suggests that this linkage between distribution connection costs and supply revenues further supports the position that both supply and delivery revenues should be considered, rather than just delivery revenues, as proposed by the MEC Coalition.

ABATE also notes the distinction between customers who pay minimum charges and those who do not in terms of reduced risk of stranded investment costs associated with distribution connections. Thus, the existence of minimum charges has an interplay with connection costs that should be recognized in the analysis, rather than just a simple payback period analysis that does not capture the risk difference.

Consumers supports ABATE's views on the extraordinary facilities exemption and recommends that if the Commission approves an alteration of residential line extension cost per foot that the allowance for C&I customers remains unchanged.

Line extension as an economic development tool

Line extension policies can be an important tool in the economic development package. Great care should be taken in considering policies that will detrimentally impact the state and local communities' ability to attract large customers.

Equity issues

The specifics of the MEC Coalition's proposal may suffer from equity issues. As described in the previous section of this report, the proposal would create a table of $/kWh allowance rates to be applied to the customer's projected energy use. For example, using data from the current Consumers electric case the MEC's Coalition's proposal results in an allowance credit rate of $0.40710 per kWh for residential customers. If a customer had an estimated monthly usage of 1,000 kWh, or 12,000 kWh annually, the customer would receive an allowance of $4,885 toward their line extension and be required to pay the excess as a refundable deposit. The flat per kWh allowance credit means that a customer using half the energy of the 1,000 kWh per month customer would also receive half as much in line extension allowance, or $2,442. A customer with a larger house or an electric vehicle would therefore be awarded a larger allowance than a customer with on-site solar generation or extensive energy efficiency investments. Any action that would drive down the customers annual energy usage would directly reduce their CIAC allowance. It seems unfair for a low-income or senior customer with relatively low annual energy consumption, for example, to receive a smaller CIAC allowance, however the higher energy use customer would still contribute more of their new revenue to offset the line extension investment. That being the case, if both the low-use and high-use customers remain in service for long enough to fully pay in for their line extension, then both can be said to be successfully entered into paying base rates; but the initial outlay for the customers remains different. A rural customer may be more likely to require a longer line extension than their urban counterpart even if they both generate the same revenue for the utility. While the urban and rural customer would have the same CIAC allowance they would face very different costs to connect to the distribution system.

Another equity issue discussed by the workgroup pertains to larger general service customers on demand rates. The MEC Coalition's proposal creates per kWh based allowance rates. The bulk of the revenue generated from Consumers general primary demand rates comes from, as the name implies, demand charges. Because the MEC Coalition's proposal relies on distribution revenues it should have noted that Rate GPD's distribution charges are only demand or customer charges and not energy billed rates. The mismatch between the MEC Coalition's proposal and existing rates for demand-billed customers can and should be easily fixable by simply using demand as the billing determinant rather than energy to calculate a demand-based allowance rate. This is already the case in DTE's tariff for large customer line extension allowances, which are all per kW credits.

Finally, any CIAC policy, existing or proposed, should consider equity in access to electric service. If electricity is requisite to living a healthy and safe life in modern society, then all who desire the service should be equally allowed reasonable and fair access.

Recommendations

Based on the discussion throughout the three workgroup meetings and condensed and presented in this report, the workgroup offers several recommendations to the Commission for considering CIAC policy. These recommendations are made on behalf of the workgroup as a whole and not just certain individual parties therein. While some recommendations may seem overall generalized it is because they come from a general group of stakeholders. That is also to say that recommendations made by any of the authors of this report in future cases or proceedings before the Commission are likely to be at odds and will require continued thoughtful consideration by the Commission.

Further consider updating the cost per foot of line extension presented in tariffs.

The workgroup discussed the origin of existing cost per foot of additional line extension beyond the 600 foot allowance and agreed that whatever data were used to create it are likely obsolete. Updating the tariff with an actual, approved cost-based charge for line extension would give confidence to customers that their refundable deposit is rooted in the actual investment made by the utility. Per the discussion in the previous section of this report, the footage allowance for line extension may also need to be readjusted in light of a different additional footage charge.

Only change CIAC policy in general rate cases and not standalone proceedings.

As explained in the discussion section of this report CIAC policy can be very influential on revenue requirement, rates, and on individual customers engaging with their utility. Line extension tariffs can even expand beyond the scope of the Commission's authority to set rates, because a CIAC policy that is too lacking or too generous to a customer can influence whether or not a new house is built, or a new business launched. The effect of CIAC policy can be observed as it flows through the financial model, cost of service study, and finally the rate design when made in a rate case. Because of the wide reaching effects of CIAC policy on the rate making process and potentially on economic development, any adjustment proposed to and approved by the Commission should only be done in the context of a general rate case proceeding.

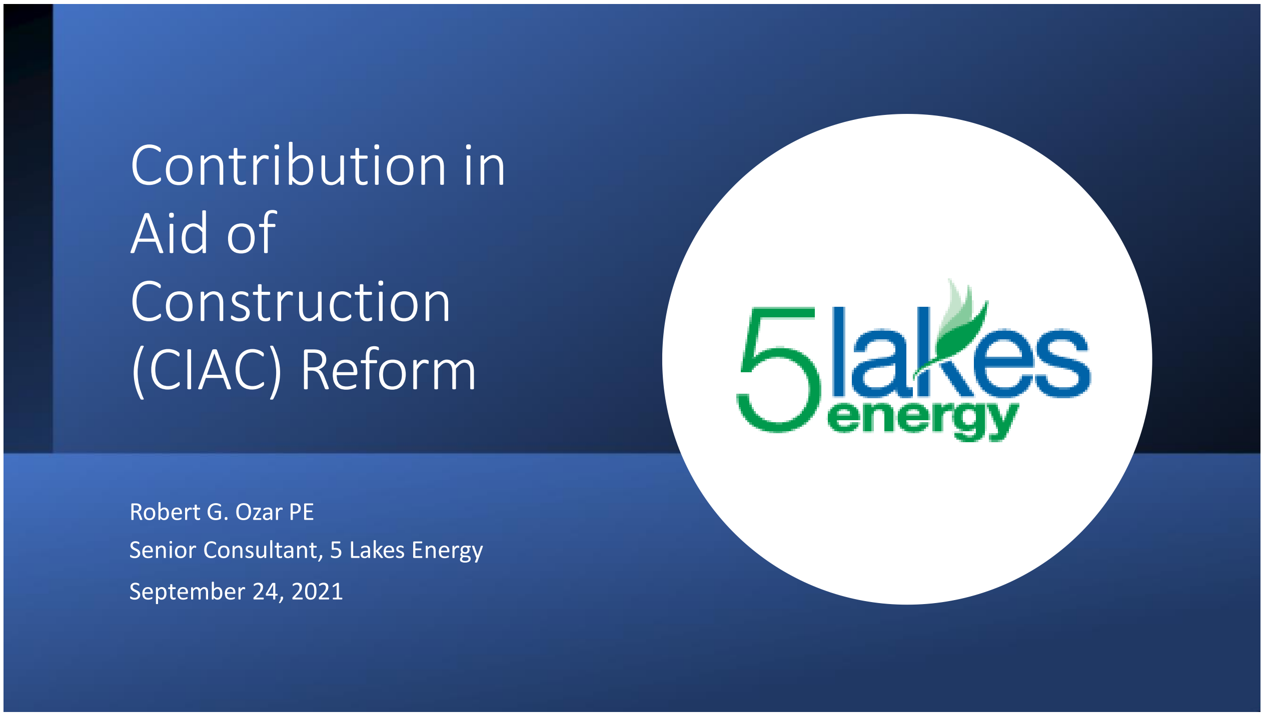
Continue CIAC workgroup meetings to further develop known issues and gather data for further analysis. Stakeholders may use the discussion and data to make proposals in future cases.

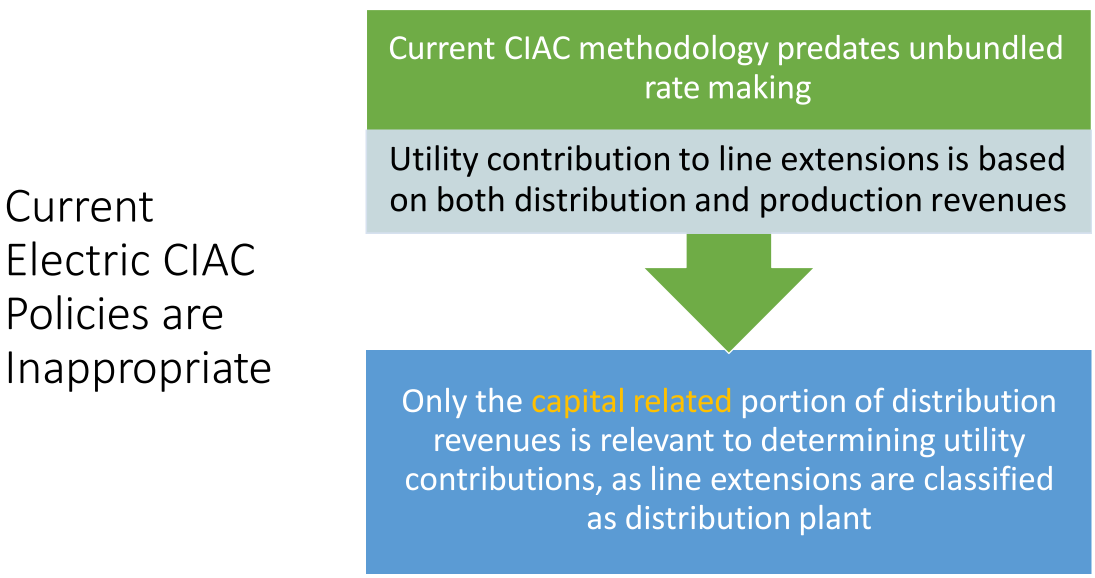
Outside of a contested rate proceeding stakeholders would be able to further discuss CIAC policy and generate novel approaches to creating equitable and fair line extension allowances. The Commission may require utilities to answer audit request from the workgroup members to gather the data needed to support alternative CIAC policy approaches. Future CIAC workgroup meetings could narrow the scope of analysis to residential line extension CIAC policy, for example, or to how CIAC policy impacts economic development.

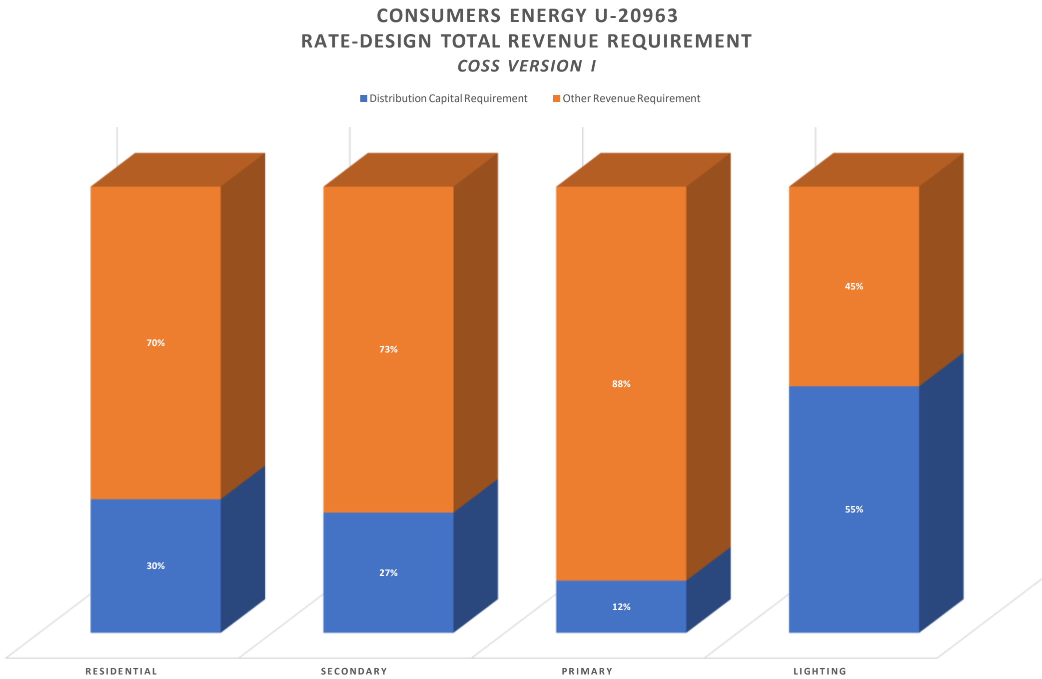
Conclusion

The CIAC Workgroup members worked prodigiously through the fall of 2021 to hold open and honest discussions on CIAC policy reform. These discussions furthered the group's understanding of CIAC policy as well as allowed workgroup members the opportunity to share their unique and diverse perspectives on the issues at hand. Continuing the conversation into 2022 will allow the workgroup to focus deliberations and encourage a robust record on CIAC in future rate case proceedings. The workgroup is pleased to present this report to the Commission for consideration.

Appendix


Contribution in Aid of Construction (CIAC) Reform
5 lakes energy
Robert G. Ozar PE
Senior Consultant, 5 Lakes Energy
September 24, 2021


Current Electric CIAC Policies are Inappropriate
Current CIAC methodology predates unbundled rate making
Utility contribution to line extensions is based on both distribution and production revenues
Only the capital related portion of distribution revenues is relevant to determining utility contributions, as line extensions are classified as distribution plant



Calculation of Payback Period for Company Contribution (Under Existing Rules)

- $Payback\ (yrs) = \dfrac{\$\ Contribution\ by\ Company}{Estimated\ Capital\ Related\ Distribution\ Revenue/yr}$

- $Payback\ (yrs) = \dfrac{(Distribution + Powersupply)\left(\frac{\$}{kWh}\right) x C\left(\frac{kWh}{Y}\right) x 3Yrs}{\left[\frac{Capital\ Related\ Distribution\ Revenue}{Distribution\ Revenue}\right] x \left[\frac{Distribution\ Revenue}{Total\ Revenue}\right] x\ (Distribution + Powersupply)\left(\frac{\$}{kWh}\right) x C\left(\frac{kWh}{Yr}\right)}$

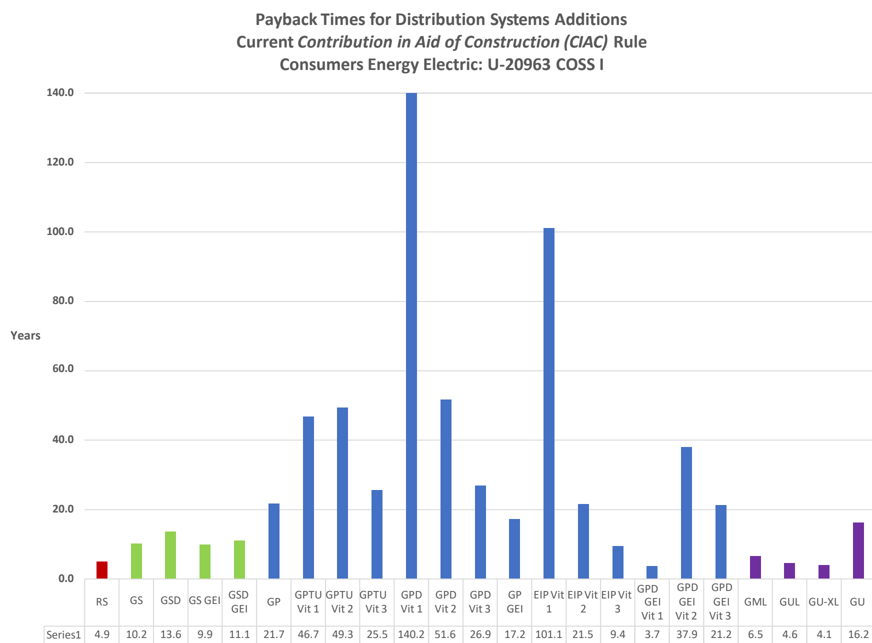
- $Payback\ (yrs) = \dfrac{3\ yrs}{\left[\frac{Capital\ Related\ Distribution\ Revenue}{Distribution\ Revenue}\right] x \left[\frac{Distribution\ Revenue}{Total\ Revenue}\right]}$

**Consumers Energy CIAC: 3xAnnual Revenue*

Payback Times for Distribution System Additions
Based on Consumers Energy Proposed Production and Distribution Re venues U-20963 COSS Version I
And Current *Contribution In Aid of Construction* Formula (3 times An nual Revenue)

Rate Schedule	Full Service Sales MWh	Distribution Sales MWh	Production Revenue (thousands)	Distribution Revenue (thousands)	Production Revenue per kWh	Distribution Revenue per kWh	Prod. + Dist. Revenue per kWh	% Distribution	Payback Years w/Distribution Revenue	Capital % of Distribution	Payback years w/Distribution Capital Revenue	% Distribution Capital
RS (Overhead Line)	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	3.52	71%	**4.9**	**30%**
RS (Underground Line)	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	7.12	71%	**10.0**	**30%**
GS	3,750,286	3,758,814	349,084	231,547	0.0931	0.0616	0.1547	40%	7.5	74%	**10.2**	**29%**
GSD	2,985,974	3,106,807	266,187	118,096	0.0891	0.0380	0.1272	30%	10.0	74%	**13.6**	**22%**
GS GEI	89,373	103,955	8,130	6,621	0.0910	0.0637	0.1547	41%	7.3	74%	**9.9**	**30%**
GSD GEI	139,134	199,503	11,795	9,749	0.0848	0.0489	0.1336	37%	8.2	74%	**11.1**	**27%**
GP	740,549	781,557	65,712	14,485	0.0887	0.0185	0.1073	17%	17.4	80%	**21.7**	**14%**
GPTU Vit 1	429,373	429,373	31,832	2,778	0.0741	0.0065	0.0806	8%	37.4	80%	**46.7**	**6%**
GPTU Vit 2	920,450	920,450	71,402	5,867	0.0776	0.0064	0.0839	8%	39.5	80%	**49.3**	**6%**
GPTU Vit 3	3,617,577	3,617,577	302,471	52,129	0.0836	0.0144	0.0980	15%	20.4	80%	**25.5**	**12%**
GPD Vit 1	1,028,117	2,088,960	53,574	2,988	0.0521	0.0014	0.0535	3%	112.3	80%	**140.2**	**2%**
GPD Vit 2	1,096,753	2,316,280	79,178	13,082	0.0722	0.0056	0.0778	7%	41.3	80%	**51.6**	**6%**
GPD Vit 3	2,041,798	2,867,360	169,649	38,560	0.0831	0.0134	0.0965	14%	21.5	80%	**26.9**	**11%**
GP GEI	90,489	124,414	8,039	3,083	0.0888	0.0248	0.1136	22%	13.8	80%	**17.2**	**17%**
EIP Vit 1	383,669	383,669	20,787	800	0.0542	0.0021	0.0563	4%	80.9	80%	**101.1**	**3%**
EIP Vit 2	64,327	64,327	3,303	699	0.0513	0.0109	0.0622	17%	17.2	80%	**21.5**	**14%**
EIP Vit 3	9,389	9,389	469	309	0.0499	0.0330	0.0829	40%	7.5	80%	**9.4**	**32%**
GPD GEI Vit 1	-	2,504	(0)	10	0.0000	0.0039	0.0039	100%	3.0	80%	**3.7**	**80%**
GPD GEI Vit 2	17,941	86,329	1,652	871	0.0921	0.0101	0.1021	10%	30.4	80%	**37.9**	**8%**
GPD GEI Vit 3	81,110	223,052	7,269	4,296	0.0896	0.0193	0.1089	18%	17.0	80%	**21.2**	**14%**
GML	13,118	13,118	672	876	0.0512	0.0668	0.1180	57%	5.3	81%	**6.5**	**46%**
GUL	62,386	62,386	3,153	13,632	0.0505	0.2185	0.2691	81%	3.7	81%	**4.6**	**66%**
GU-XL	19,268	19,268	939	9,742	0.0487	0.5056	0.5543	91%	3.3	81%	**4.1**	**74%**
GU	100,655	100,655	7,599	2,243	0.0755	0.0223	0.0978	23%	13.2	81%	**16.2**	**18%**

Sources: Exhibit A-16, Schedule F1, pages 2-3 (Excel Version)



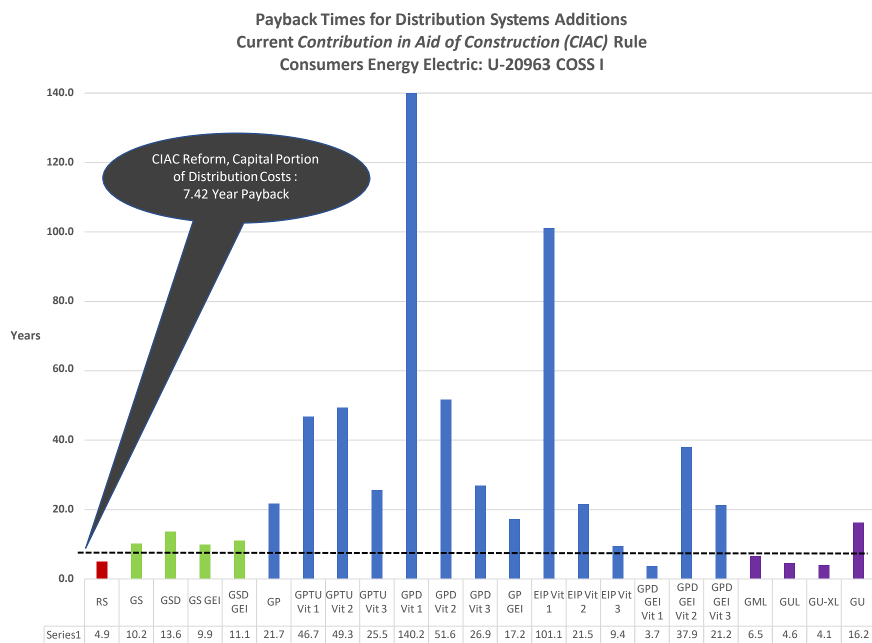
The Same Payback Should be Set for Customers Under all Rate Classes

- The correct **uniform** payback-period is the reciprocal of the *economic carrying cost* of total electric distribution capital investments:

- $Payback = \dfrac{1}{Economic\ Carrying\ Cost} = \dfrac{1}{\left[\dfrac{Lifecycle\ Average\ Revenue\ Requirement}{Undepreciated\ Balance\ of\ Investment}\right]}$

- $Payback \approx \dfrac{Electric\ Distribution\ Ratebase}{Capital\ Portion\ of\ Distribution\ Revenue\ Requirement}$

- $Payback = \dfrac{\$8{,}145{,}807{,}000}{\$1{,}505{,}709{,}000/yr} = \boxed{7.42\ yrs}$ (CE U-20963 COSS version I)



Uniform Payback Under CIAC Reform

Consumers Energy example (based on its U-20963 COSS Version I):

Free allowance = 7.42 times the capital-related portion of electric distribution rate design revenue ($/kWh), for the appropriate rate class), times the end-user's estimated kWh sales.

Would replace current standard of 3 times estimated total annual revenue.

The Capital-Related Portion of Electric Distribution Rate Design Revenue

Rate Schedule	Full Service Sales MWh	Distribution Sales MWh	Production Revenue (thousands)	Distribution Revenue (thousands)	Production Revenue per kWh	Distribution Revenue per kWh	Prod. + Dist. Revenue per kWh	% Distribution	Capital % of Distribution	Capital Portion Distribution Rev. $/kWh
RS	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	71%	**$ 0.0548**
GS	3,750,286	3,758,814	349,084	231,547	0.0931	0.0616	0.1547	40%	74%	**$ 0.0455**
GSD	2,985,974	3,106,807	266,187	118,096	0.0891	0.0380	0.1272	30%	74%	**$ 0.0281**
GS GEI	89,373	103,955	8,130	6,621	0.0910	0.0637	0.1547	41%	74%	**$ 0.0471**
GSD GEI	139,134	199,503	11,795	9,749	0.0848	0.0489	0.1336	37%	74%	**$ 0.0361**
GP	740,549	781,557	65,712	14,485	0.0887	0.0185	0.1073	17%	80%	**$ 0.0148**
GPTU Vit 1	429,373	429,373	31,832	2,778	0.0741	0.0065	0.0806	8%	80%	**$ 0.0052**
GPTU Vit 2	920,450	920,450	71,402	5,867	0.0776	0.0064	0.0839	8%	80%	**$ 0.0051**
GPTU Vit 3	3,617,577	3,617,577	302,471	52,129	0.0836	0.0144	0.0980	15%	80%	**$ 0.0115**
GPD Vit 1	1,028,117	2,088,960	53,574	2,988	0.0521	0.0014	0.0535	3%	80%	**$ 0.0011**
GPD Vit 2	1,096,753	2,316,280	79,178	13,082	0.0722	0.0056	0.0778	7%	80%	**$ 0.0045**
GPD Vit 3	2,041,798	2,867,360	169,649	38,560	0.0831	0.0134	0.0965	14%	80%	**$ 0.0108**
GP GEI	90,489	124,414	8,039	3,083	0.0888	0.0248	0.1136	22%	80%	**$ 0.0198**
EIP Vit 1	383,669	383,669	20,787	800	0.0542	0.0021	0.0563	4%	80%	**$ 0.0017**
EIP Vit 2	64,327	64,327	3,303	699	0.0513	0.0109	0.0622	17%	80%	**$ 0.0087**
EIP Vit 3	9,389	9,389	469	309	0.0499	0.0330	0.0829	40%	80%	**$ 0.0264**
GPD GEI Vit 1	-	2,504	(0)	10	0.0000	0.0039	0.0039	100%	80%	**$ 0.0031**
GPD GEI Vit 2	17,941	86,329	1,652	871	0.0921	0.0101	0.1021	10%	80%	**$ 0.0081**
GPD GEI Vit 3	81,110	223,052	7,269	4,296	0.0896	0.0193	0.1089	18%	80%	**$ 0.0154**
GML	13,118	13,118	672	876	0.0512	0.0668	0.1180	57%	81%	**$ 0.0542**
GUL	62,386	62,386	3,153	13,632	0.0505	0.2185	0.2691	81%	81%	**$ 0.1773**
GU-XL	19,268	19,268	939	9,742	0.0487	0.5056	0.5543	91%	81%	**$ 0.4102**
GU	100,655	100,655	7,599	2,243	0.0755	0.0223	0.0978	23%	81%	**$ 0.0181**

Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I

CIAC Reform – Utility Contribution - Based on End User's Estimated Annual (kWh)

7.42 times the capital-related portion of electric distribution rate design revenue ($/kWh)

Rate Schedule	Credit $/kwh
RS	0.40710
GS	0.33805
GSD	0.20860
GS GEI	0.34951
GSD GEI	0.26817
GP	0.11019
GPTU Vit 1	0.03847
GPTU Vit 2	0.03790
GPTU Vit 3	0.08567
GPD Vit 1	0.00850
GPD Vit 2	0.03358
GPD Vit 3	0.07995
GP GEI	0.14731
EIP Vit 1	0.01240
EIP Vit 2	0.06460
EIP Vit 3	0.19592
GPD GEI Vit 1	0.02319
GPD GEI Vit 2	0.05996
GPD GEI Vit 3	0.11450
GML	0.40225
GUL	1.31620
GU-XL	3.04535
GU	0.13424

Applied to estimated annual usage (kWh)

Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I

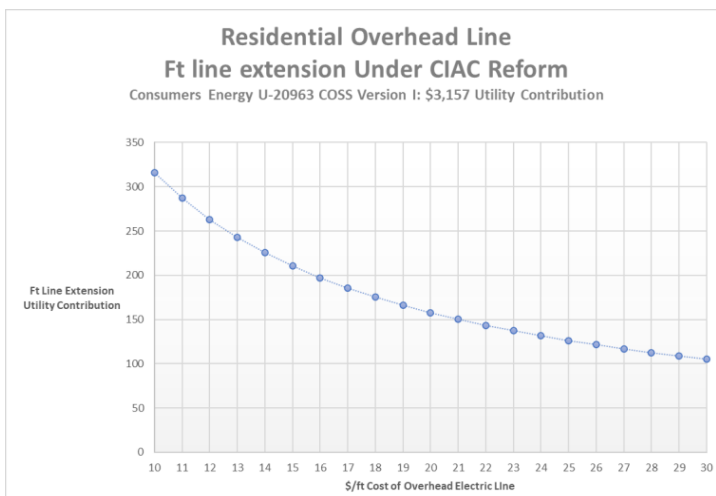
Residential CIAC Overhead Electric Line

Consumers Energy current CIAC rule allows for 1st 600 ft to be covered at the utility expense.

Under CIAC reform, length of "free" extension would depend on cost/ft.

	Current Framework Total Revenue	Distribution Revenue	CIAC REFORM Capital Portion Revenue
Residential kWh/yr	7,754	7,754	7,754
Rate $/kWh	0.1827	0.0770	0.0548
Revenue $/yr	1417	597	425
Payback Period	3		7.42
$ Company Contribution	**$ 4,250**		**$ 3,157**

35% TOO HIGH



Conclusions & Recommendations

1) Payback associated with utility contribution-in-aid-of-construction should be **uniform** across all rate classes.
2) The uniform payback (*x Yrs.)* should be based on the **reciprocal of the economic carrying cost of electric distribution capital investment**.
3) The **capital portion** of distribution revenue requirements (%) should be calculated for each customer class (residential, secondary, primary, lighting).
4) The capital portion of the rate-design distribution-revenue ($/kWh) is calculated as product of (3) and the rate design distribution revenue ($/kWh) for full service + ROA sales.
5) Free allowance ($/ kWh of estimated annual usage, for each rate class) is calculated as the product of (4) and the uniform payback period (*2).*
6) The per kWh allowance for each rate class (5) should be reflected in a **schedule**, updated in each general rate proceeding. The per kWh allowance is applied to the end-user's estimated annual usage (kWh)
7) With respect residential **overhead line-extensions**, the maximum # of feet allowed at the utility's expense should be fixed in each rate case, based upon the per kWh residential allowance reflected in (6) times the class average sales per customer (from the COSS) divided by the current cost per foot also set in each rate case.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Ex Parte Approval of Certain Amendments to Rate GPD.	Case No. U-21859

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony and Exhibits of Caroline Palmer on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (MEC-5 through MEC-23)** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

TROPOSPHERE LEGAL, PLC
Counsel for MNSC

Date: June 12, 2025

By: Natasha L. Fowles Digitally signed by Natasha Fowles Date: 2025.06.12 18:12:17 -04'00' ______________________

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