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August 27, 2020

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

Re: **MPSC Case No. U-20697**

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the Initial Brief of Michigan Energy Innovation Business Council and Institute for Energy Innovation. Thank you for your assistance in this matter.

Very truly yours,

VARNUM

Laura A. Chappelle

LAC/sej
Enclosures
c. All parties of record.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief	))))))	**Case No. U-20697**

INITIAL BRIEF OF THE
MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL
AND
INSTITUTE FOR ENERGY INNOVATION

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Contents

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I. INTRODUCTION

This Initial Brief is filed on behalf of the Michigan Energy Innovation Business Council ("Michigan EIBC") and the Institute for Energy Innovation ("IEI"), collectively, "Michigan EIBC/IEI," by their attorneys Varnum LLP. Failure to address any issues or positions raised by other parties should not be taken as agreement with those issues or positions.

II. BACKGROUND

On February 27, 2020, Consumers Energy Company ("Consumers" or the "Company") filed an application for authority to increase its rates for the generation and distribution of electricity and for other relief in this proceeding ("Application"). Michigan EIBC/IEI is particularly interested in three aspects of Consumers' Application: (1) a new, proposed Distributed Generation ("DG") tariff; (2) proposed changes to its stand-by rates, in tariff GSG-2, and (3) a new proposal for a three-year PowerMIFleet Pilot Foundational Infrastructure Program ("PowerMIFleet Pilot Program").

III. THE COMMISSION SHOULD REJECT CONSUMERS' PROPOSED DG TARIFF AS IT VIOLATES THE LAW AND COMMISSION PRECEDENT, IS NOT EQUITABLE, AND IS NOT BASED ON ESTABLISHED COST OF SERVICE RATES.

A. DG Tariff Background

Section 6a(14) of 2016 Public Act 341; MCL 460.6a(14) ("Section 6a(14)" and "Act 341," respectively) requires any DG tariff approved by the Commission to be (1) equitable, and (2) based on the utility's actual costs to serve DG customers.

> Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting **equitable cost of service** for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211…

Section 6a(14) (emphasis added). The fundamental requirements in Section 6a(14) that all rates be equitable and cost-based are consistent with other requirements of Michigan law, including Sec. 11(1) of Act 341, which provides that:

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. …

Furthermore, when proposing a rate, Michigan law requires the utility to "place in evidence facts relied upon to support the utility's petition." MCL 460.6a(1). The Commission has explained that this evidence must be "thorough, detailed, and meaningful" and it must be sufficient to "support a finding that that the costs are just and reasonable." Case No. U-16794, Order of June 7, 2012 at 13. Thus, fundamentally, Michigan law requires all rates to be equitable, cost-based and evidence-based.

In this case, Consumers proposes to implement a new DG tariff pursuant to Section 6a(14) and the Commission Order of April 18, 2018 in Case No. U-18383. Consumers' witness Hubert W. Miller III provides Consumers' description and justification of the DG tariff, while implementing language is proposed by Consumers' witness Rachel Barnes in Exhibit A-16 (RLB-2) Schedule F-5, especially Rule C.11 on Sheets C-58.00 through C-64.80. The DG tariff will apply to customers who have an "Eligible Electric Generator" behind the meter that measures Consumers' electrical services to that customer. An Eligible Electric Generator must be limited to producing 100% of the customer's electricity consumption for the previous 12 months and

- for a renewable energy system, does not exceed 150 kW of aggregate generation at a single site,
- for an anaerobic digester, does not exceed 550 kW of aggregate generation at a single site.

8 TR 4482. The proposed DG tariff will replace the existing practice of Net Energy Metering. Consumers proposes to accept applications for participation in Net Energy Metering until 4:59 P.M. Eastern Standard Time on January 2, 2021, subject to certain program capacity limits. Thereafter, a customer seeking to install an Eligible Electric Generator will be able to participate in the DG tariffed program, subject to certain program capacity limits. 2 TR 4483.

According to Section 183 of 2016 PA 342, "A customer participating in a net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of enrollment." As Michigan EIBC/IEI witness Douglas B. Jester noted, "[A]lthough Consumers' proposed tariff language does not explicitly deal with this eventuality, presumably customers who are currently participating in Net Energy Metering will be removed from Net Energy Metering and transferred to the DG tariff ten years after their original enrollment in Net Energy Metering. Since Net Energy Metering became available in 2009, some customers will be immediately affected" *Id*.

Section 173 of 2008 PA 295, as amended by 2016 PA 342, places a flexible program capacity cap to allow for a distributed generation program in excess of certain penetration levels. As Mr. Jester noted, in this case, Consumers does not propose to allow participation in a distributed generation program in excess of those limits, although it could legally do so. 8 TR 4483.

The program capacity flexible caps, provided by Section 173 of 2008 PA 295, as amended by 2016 PA 342, apply to the combined participation by customers who are in the Net Energy Metering program and those who are participating in the DG program described by the DG tariff. Those caps are provided in Section 173(3) of 2008 PA 295 as amended by 2016 PA 342:

> (3) An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding 5 calendar years. The electric utility or alternative electric supplier shall notify the commission if its distributed generation program reaches the 1% limit under this subsection. The 1% limit under this subsection shall be allocated as follows:
>
> (a) No more than 0.5% for customers with an eligible electric generator capable of generating 20 kilowatts or less.
>
> (b) No more than 0.25% for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 150 kilowatts.
>
> (c) No more than 0.25% for customers with a methane digester capable of generating more than 150 kilowatts.

8 TR 4484. For the reasons stated below, Michigan EIBC/IEI submit that Consumers' proposed new DG tariff fails to follow established law and Commission orders, is inequitable and is not cost-based. Consumers' proposed DG tariff, therefore, should either be rejected by the Commission or accepted with the changes requested by Michigan EIBC/IEI.

B. Argument

1. Consumers' Proposed DG Outflow Methodology Should Be Rejected By The Commission As Violative Of Statutory Law And The Commission's Orders.

Per Consumers' witness Miller, the Company proposes to implement a DG tariff similar to that approved in the DTE Electric Company's ("DTE") electric rate case in Case No. U-20162. Generally, the proposed tariff is based on the "inflow/outflow" methodology, where the "inflow" is at the customer's retail electric rate and the "outflow" is at "its embedded production rates (power supply less transmission) for the excess power from DG customers, which will be applied as an offset to the production section of their monthly energy bill." 4 TR 577.

In determining the outflow credit, the Company limited the credit to only the total power supply charges on the customer's bill, based upon its interpretation of Section 177(4) of Public Act 342 of 2016, which provides:

> (4) If the quantity of electricity generated and delivered to the utility distribution system by an eligible electric generator during a billing period exceeds the quantity of electricity supplied from the electric utility or alternative electric supplier during the billing period, the eligible customer shall be credited by their supplier of electric generation service for the excess kilowatt hours generated during the billing period. The credit shall appear on the bill for the following billing period and shall be limited to the total power supply charges on that bill. Any excess kilowatt hours not used to offset electric generation charges in the next billing period will be carried forward to subsequent billing periods. Notwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges. The credit per kilowatt hour for kilowatt hours delivered into the utility's distribution system shall be either of the following:

> (a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory, or for distributed generation customers on a time-based rate schedule, the monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.
>
> (b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

MCL 460.1177(4) ("Section 177(4)"). Company witness Miller testified, in part, that the proposed outflow credit only included power supply (i.e., production) credits because "the language in Section 177(4) [provides] that the compensation credits shall exclude transmission and delivery charges." 4 TR 578.

As an initial matter, the Company's interpretation of Section 177(4), which the Company alleges limits the outflow credit to only the total power supply charges on the bills, thus excluding transmission and delivery charges, has been clearly and definitively rejected by the Commission in its final Order in Case No. U-18383, which set the framework for utility distribution generation tariffs. 8 TR 4444-4445. More specifically, Consumers made this same argument in Case No. U-18383, for which the Commission responded by stating that "[the] Commission disagrees with this interpretation."[1] 8 TR 4445. According to the Commission:

> The second issue raised by DTE Electric and Consumers relates to the limitation of accumulated credits against future bills. In comments, DTE Electric and Consumers made the argument that any DG credit cannot be used to reduce distribution or transmission charges. This is an incorrect interpretation of Section 177(4). The relevant subsection (4) provision states, "[n]otwithstanding any law or regulation, distributed generation customers shall not receive credits for electric utility transmission or distribution charges." This exclusion refers to the formula for calculating compensation, which is expressed in the dual credit pricing options (LMP

[1] MPSC Order, Case No. U-18383, dated April 18, 2018 ("Order U-18383"), p. 13.

> or power supply component excluding transmission charges), that immediately follows the prohibition. Under any reasonable interpretation, the transmission and distribution exclusion cannot refer to the level of accrued credits that can be applied to the customer bill for the following billing period since subsection (4) expressly allows the offset of the total power supply charges (which include transmission charges). Clearly, the transmission and distribution exclusion only applies to the modified net metering formula for calculating credits for the portion of outflow that exceeds inflow. Further, if the credit limitation applied across the board, i.e., to total outflow, then both true net metering and modified net metering would be prohibited by subsection (4) since both billing methods credit power inflows at the full retail rate (which includes transmission and distribution charges). The utilities' interpretation of Section 177(4) sets the statute in conflict with itself and is thus erroneous.[2]

Thus, the Commission has previously found that "Section 177 does not apply to any DG billing method, such as the Inflow/Outflow billing mechanism, that implements a COS [Cost of Service] based tariff under Act 341, Section 6a(14)."[3] As the Commission has already found that Section 177(4) applied to "modified net metering" and not to the distributed generation tariff under Section 6a(14), Consumers' proposed Outflow credit, which is affirmatively based on Section 177(4) and excludes transmission costs from the Outflow credit, should be rejected.

2. The Commission Should Include Transmission Costs In The Outflow Credit For Consumers' DG Tariff.

In addition to relying on Section 177(4) to exclude transmission costs from the Outflow credit, Consumers' witness Miller asserts that "[i]ncluding transmission in the outflow credit would essentially compensate the homeowner with a private solar array for a service they are not providing, thereby increasing the energy bill of their neighbor." 4 TR 578-579. This assertion has been discredited by several expert witnesses in this proceeding.

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[2] *Id.*, p. 14 (emphasis added).
[3] *Id.*, p. 15.

First, witness Miller premises this assumption on a 2019 study, published by Fischer *et al.*, entitled, "*Energy and Buildings*" ("Fischer Report").[4] Referencing the Fischer Report, Consumers' witness Miller testified that:

> Including transmission in the outflow credit would essentially compensate the homeowner with a private solar array for a service they are not providing, thereby increasing the energy bill of their neighbor. Although some advocates have argued that DG customers benefit the grid, I have yet to find any compelling research supporting this claim. Indeed, the literature generally suggests that increasing the penetration of solar on the grid increases the intra-day variations in load and may not notably affect the annual load peak of households.

4 TR 578-579. Mr. Miller's analysis of the Fischer *et al.* study, however, was discredited by Michigan EIBC/IEI witnesses Dr. Laura S. Sherman and Douglas B. Jester, as well as the Ecology Center, Environmental Law & Policy Center, Great Lakes Renewable Energy Association, Solar Energy Industries Association, and Vote Solar ("collectively, the "Joint Clean Energy Organizations" or "JCEO") witness Karl R. Rábago, all of whom found Mr. Miller's analysis misleading and incorrect. Specifically, Dr. Sherman found that:

> As noted by Witness Miller, Fischer et al. do conclude that the addition of solar PV systems without battery storage and without controls (e.g., appropriate price signals) increase the intra-day variations in load. <u>However, the study does not conclude, as suggested by Witness Miller, that solar PV "may not notably affect the annual load peak of households." In contrast, the authors show that "[adding] PV reduces the net electricity demand of the corresponding building group from 870 MWh/a to -214 MWh/a, with an annual self-consumption of 440 MWh/a, making them net electricity producers."</u> More generally, the referenced study is a neighborhood scale model set in Potsdam, Germany – not a broad analysis of the impacts of solar PV on the grid or a prediction of the need for future transmission upgrades.

8 TR 4448 (emphasis added). Similarly, Mr. Rábago testified that:

[4] Fischer, D., Surmann, A., and Lindberg, K, Impact of emerging technologies on the electricity load profile of residential areas. Energy and Buildings, 2020, vol 208, https://www.researchgate.net/publication/337579834_Impact_of_emerging_technologies_on_the_electricity_load_profile_of_residential_areas, ("Fischer Report").

> Mr. Miller's citation to the study is misleading. The study is based on fairly advanced modeling of a dense cluster of homes—1,550 homes located in a city area of 1 square kilometer, with very high penetrations of several kinds of DERs, forecasted into the future. Contrary to Mr. Miller's description, the study assumes that PV systems are sub-optimally sized, as are customer-sited battery systems. <u>The study finds that "efficiency gains in household devices, with annual energy savings of 28%, together with the introduction of local production from PV [solar], *compensate* for the additional electricity demand."</u> The study further identifies heat pumps and electric vehicles as primary drivers of load variability, not solar, and concludes, quite reasonably, that "[i]n a future facing increased electrification of the energy system, careful design of control strategies is therefore recommended." <u>These findings and the conclusion are almost completely inconsistent with the way Mr. Miller described the research. The study Mr. Miller cites cannot be used to support his conclusion that transmission offset credits should not be part of the outflow credit. Mr. Miller cites no other literature in his testimony to support his assertions</u>.

8 TR 4370-4371 (emphasis added). And finally, Michigan EIBC/IEI witness Jester stated that "This argument fails because Consumers' costs for transmission are, or can be, reduced by the outflow from a customer with distributed generation." 8 TR 4497.

As witness Miller's "findings" of the study by Fischer *et al.* are clearly at odds with the actual contents and findings of the study itself, the Company's reliance on the study to allegedly substantiate its restriction of utilizing transmission offset credits should be given no weight or credibility.

A far more timely, relevant and credible report was discussed at length by Michigan EIBC/IEI witness Dr. Sherman. Specifically, Dr. Sherman provided testimony that described the report she co-authored in 2017 detailing the benefits of solar DG systems ("MI Solar Energy Report").[5] In part, the MI Solar Energy Report analyzed previous meta-analyses,[6] which

[5] Institute for Energy Innovation, Solar Energy in Michigan: The Economic Impact of Distributed Generation on Non-Solar Customers, 2017. https://mieibc.org/wp-content/uploads/2018/04/Econ-Impact-non-solar-summary.pdf ("MI Solar Energy Report").

[6] A meta-analysis is a study that looks at a wide number of other studies and compiles the data into one broad analysis.

together evaluated a total of more than 40 solar PV studies across the country, in addition to nine more recent studies published since 2015. Dr. Sherman stated that "The meta-analyses found that there were many benefits of solar distributed generation systems including: avoided distribution system line losses, avoided investments in transmission and distribution capacity, grid support services, avoided risk of increased fuel prices, grid reliability and resiliency, environmental and health benefits, and societal benefits.[7] [8] [9] [10] [11] [12] [13] Although some of these benefits can be more difficult to monetize, studies conducted across the country have effectively and quantitatively taken them into account. It is clear from these multiple studies that one of the benefits of distributed generation is avoided investments in the transmission system. Despite witness Miller's assertion that '[although] some advocates have argued that DG customers benefit the grid, I have yet to find any compelling research supporting this claim,' there is a long-standing and well-researched body of information clearly proving and detailing the benefits that distributed solar provides to the grid." 8 TR 4449-4450.

Moreover, the Commission expressly found that a future outflow credit could be used to reduce distribution and transmission charges and did not need to be limited to only reducing

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[7] Muro M, Saha D. Rooftop solar: Net metering is a net benefit, Brookings Institution, 2016. https://www.brookings.edu/research/rooftop-solar-net-metering-is-a-net-benefit/.

[8] Weissman G, Fanshaw B., Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society, https://www.seia.org/research-resources/shining-rewards-value-rooftop-solar-power-consumers-and-society

[9] Hansen L, Lacy V, Glick D., A Review of Solar PV Benefit & Cost Studies, Electricity Innovation Lab, Rocky Mountain Institute, 2013.
https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf

[10] Norris BL, Gruenhagen PM, Grace RC et al., Maine Distributed Solar Valuation Study, Maine Public Utilities Commission, 2015.
https://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOSFullRevisedReport_4_15_15.pdf

[11] Crossborder Energy, The Alliance for Solar Choice, Filing in the Matter of the Arizona Corporation Commission's Investigation of Value and Cost of Distributed Generation, Docket No. E-00000J-14-0023, 2016. https://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=18350

[12] Price S, Ming Z, Ong A et al., Nevada Net Energy Metering Impacts Evaluation 2016 Update, 2016. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf

[13] Xcel Energy, VALUE OF SOLAR Calculation, submitted to Minnesota Public Service Commission: Docket No. E002-M-13-867, 2016.

power supply charges. 8 TR 4445. In fact, as JCEO witness William D. Kenworthy testified, the Commission has instituted an outflow credit that reduced transmission charges for two other utilities' DG tariffs. In the order approving the Settlement Agreement in the UPPCo rate case, Case No. U-20276, the Commission approved a DG Program rider that included an outflow credit equal to the full power supply component of the DG customer's rate schedule (thereby including transmission in the outflow credit). In addition, the Commission approved a settlement in the Indiana Michigan Power Company's rate case (U-20359) that included a DG tariff that is structurally very similar to the DG program approved in the UPPCo case. Thus, unlike DTE's DG rider, on which Consumers bases its proposed DG tariff, both of these more recent Commission-approved riders include transmission in the credit for outflow. 8 TR 4154-4155.

In response to Consumers' assertion that an outflow credit based on power supply less transmission fairly compensates DG customers for outflow, Staff witness Kevin Krauss responded that the word "fairly" is unclear in a regulatory context and instead, simply stated that the outflow credit of power supply less transmission is "reasonable." Discovery Response 20697-CE-ST-6. In response to Consumers' attempts to have Staff admit that the outflow credit should not exceed the Company's power supply less transmission charges, Staff witness Krauss countered that "Staff believes that the outflow credit of full power supply established in the settlement agreement in UPPCo's past rate case, U-20276, that was agreed to by all parties, and approved by the Commission in its 5/23/2019 Order is also reasonable." Discovery Response 20697-CE-ST-7.

For all of these reasons, Michigan EIBC/IEI respectfully request that the Commission find that: (1) Consumers errs in basing its outflow credit on Section 177(4); (2) the value of outflow should not be limited to either LMP or the power supply component of the full retail rate excluding transmission; and (3) outflow credits can and should be used to reduce distribution and transmission charges.

3. Consumers Should Allow Customers To Participate In The DG Program Above And Beyond The Current Soft Caps.

Consumers' proposed Rule C11.3.B.7 sets a program cap for DG as follows:

> Program Capacity – maximum program limit of 1% of the Company's average Peak Demand for Full-Service Customers during the previous five calendar years. Within the Program Capacity, 0.5% is reserved for Category 1 Net Metering Customers, 0.25% is reserved for Category 2 Net Metering Customers and 0.25% is reserved for Category 3 Net Metering Customers.

Michigan EIBC/IEI respectfully submit that this proposed rule, which would cap net metering/DG program participation at 1%, should be rejected and the Company should voluntarily agree to remove the caps on distributed generation, as explained in further detail below.

As previously stated, the customer participation level for utility DG programs was established in 2008 PA 295, and was retained in Section 173(3) of PA 342. As JCEO witness Kenworthy testified, while the 1% requirement "is often characterized as a cap on participation in distributed generation, it is important to note that it is in fact a minimum participation level which the utility must allow. There is no limitation in the statute on the utilities' ability to extend participation beyond the minimum." 8 TR 4173.

Similarly, Michigan EIBC/IEI witness Dr. Sherman found that:

> Although an electric utility is allowed in statute to increase the size of its DG program above 1% of its average in-state peak load for the preceding 5 calendar years, there is no requirement that they do so. However, there is no statutory prohibition on a utility either increasing the size of its DG program or simply allowing customers to continue to participate in the DG program once they reach the initial caps. It is important to note that because 25% of the total cap is reserved for methane digesters, only 75% of the total amount is available for solar DG systems. It is also important

> to understand that because the cap is based on a utility's average in-state peak load, a 0.75% solar soft cap equates to a much smaller percentage of the electricity flowing through the distribution grid. Specifically, based on a back-of-the-envelope calculation, if a given utility reached the 0.75% solar cap, it would mean that only approximately 0.16% of the electricity sold by that utility is actually coming from DG solar systems.

8 TR 4453-4454. Consumers has admitted that it will likely reach the limits of Category 1 within months, and Category 2, within approximately 1 year. The table, below, prepared by JCEO, details the responses from the Company to discovery requests by Michigan EIBC/IEI and other parties to this proceeding as of April 14, 2020, when the discovery answer was completed:[14]

Table 2: Distributed Generation Program Minimum Capacity

Row Number	Item	Category 1	Category 2	Category 3
1	Currently Applicable Minimum	36,405 kW	18,203 kW	18,203 kW
2	Current Installed Capacity	25,433 kW	11,152 kW	190 kW
3	Capacity Remaining	10,972 kW	7,051 kW	18,013 kW
4	Average applications per month (through February 2020)	1,045 kW	538 kW	0 kW

Specifically, in response to discovery question EIB-2 (LSS-2), Consumers indicated that due to the uncertain impacts of the ongoing COVID-19 pandemic, it is not entirely clear when the Category 1, 2, and 3 DG caps will be met. However, the Company estimates that the 0.5% capacity in Category 1 could be reached in October 2020 and the 0.5% capacity for Category 2 could be reached by the end of 2021. 8 TR 4452. It is important to note that these estimates were completed more than four months ago. It is very likely that installations for Category 1 and 2 are now even higher.

[14] Table: Direct Testimony of William D. Kenworthy, U-20697, 8 TR 4174, Reference: Rows 1-3 of the table below summarize information from U20697-MEIBC-CE-198, U20697-MEIBC-CE-199 and U20697-MEIBC-CE-200, provided as Exhibits CEO-2 (WDK-2) , CEO-3 (WDK-3), and CEO-4 (WDK-4). Row 4 of the table shows the average rate at which applications have been submitted to the Company over the 11-month period through February of this year.

Michigan EIBC/IEI witness Dr. Sherman testified as to many of the issues that both customers and solar installers will encounter if the DG cap is not lifted. For customers, Dr. Sherman testified that the end of the DG program not only means the loss of the incentive for customers to self-generate renewable energy in order to support renewable energy goals and to receive just and reasonable compensation for contributing energy and capacity to the grid, but will also create uncertainty for those with either current distributed generation systems and those who may seek to install solar systems in the future.

First, as Dr. Sherman noted, the Company's proposal to compensate customers after the cap is reached for energy only, at the Mid-Continent Independent System Operator's ("MISO") real-time Locational Marginal Price ("LMP") rate, would not amount to a cost-of-service based value for the outflow from solar DG systems. As explained in greater detail by Dr. Sherman and other expert witnesses to this proceeding, "there are many quantifiable, measured and researched benefits of solar DG that would not be equitably accounted for" with an LMP-based energy only rate. 8 TR 4460. Paying solar generating customers only a spot market-based RTO price for energy once the DG caps are reached would undercompensate the customer, and overcompensate the Company, for the value that the distributed generation system is providing.

Second, Dr. Sherman highlighted the fact that there are no protections for DG customers outside of the DG program. Specifically, without access to the DG program, customers are not guaranteed appropriate timelines for application steps and interconnection, appropriate and reasonable fees, access to and knowledge of the appropriate utility personnel, ability to leave the program without a termination fee, or use of standardized interconnection applications. At the direction of the legislature, the Commission created these protections under the net metering/DG program and oversaw the creation of utility procedures for the same program. Without access to the DG program, customers in Michigan will lose all of the critical protections and guarantees currently afforded to them as residents investing their own funds to install renewable energy systems on their own property. 8 TR 4459-4460.

Equally as important, Dr. Sherman discussed the expected detrimental impact to the solar industry in the state if Consumers reaches the DG caps and does not allow customers to access the DG program, by testifying that:

> Prior to the pandemic, there were more than 126,000 advanced energy jobs in Michigan and 5,400 of those were solar jobs.[15] Unfortunately, in March and April of this year, more than 30,000 advanced energy jobs were lost in Michigan.[16] As in other industries, small businesses, including solar installers, have taken the brunt of these job losses.
>
> According to business members of Michigan EIBC, the potential closure of the distributed solar market due to Consumers Energy and other utilities reaching the solar caps poses an existential threat to the industry. It is difficult for companies to consider rehiring workers or expanding in Michigan when the market may literally be closed in 7 months. These concerns are detailed by David Lewenz, National Director of Business Development & Commercial Operations for Power Home Solar in Exhibit EIB-7 (LSS-7). According to Mr. Lewenz,
>
>> Power Home Solar is especially concerned that if the Michigan Public Service Energy will be allowed to deny any customer interconnection application without cause. … If the distributed generation cap is not lifted or raised significantly, and if the Commission allows Consumers to unilaterally deny customer interconnections, Power Home Solar, in all likelihood, will need to decrease operations in Michigan, lay off employees, and focus our operations in other states.

8 TR 4462-4463.

Given that these caps will be met shortly, several parties, including witness Dr. Laura Sherman, recommended that the cap should be increased or removed by the Company in this proceeding. 8 TR 4452. As Dr. Sherman testified, there have been no expressed concerns

[15] Clean Jobs Midwest 2019. https://www.cleanjobsmidwest.com/state/michigan
[16] Clean Jobs America 2020. https://e2.org/reports/clean-jobs-america-2020/

related to reliability of the distribution system related to solar DG systems. 8 TR 4454-4455. Thus, Dr. Sherman testified:

> . . . the original caps were put in place when the net metering program was first established. The legislature clearly enabled, but did not require, the electric utilities to allow additional participants to participate in the DG program above the caps. There is no statutory prohibition on a utility either increasing the size of its DG program or simply allowing customers to continue to participate in the DG program once they reach the initial caps. Practically, this has already happened in UPPCO's territory as the result of a Commission approved Settlement agreement in Case No. 20276.

8 TR 4461.

In addition, MPSC Staff COO Mike Byrne recently testified before the Senate Energy and Technology Committee regarding SB 597(S-1) that given the lack of engineering issues, and with a cost-based DG tariff, a system-wide DG cap in not necessary. Thus, Mr. Byrne stated, in part, that:

> As we previously indicated, Michigan's regulated utilities are beginning their current cap set-asides for category 1 systems (systems under 20 kw) and we expect this trend to continue, albeit at a slower rate, even after inflow/outflow is fully integrated into all regulated utility tariffs.
>
> In our discussions with NREL and the HPUC, it was confirmed that there is no engineering reason to set a system-wide DG cap. Rather, reliability and integration issues arise on a circuit by circuit basis and must be addressed on that level. Additionally, provided that a cost-of-service based tariff is in effect, the economic reasons for a DG program cap are also eliminated. Because there is no engineering reason for a system-wide cap, and because we believe a cost-of-service based tariff is in effect for Michigan's regulated utilities, **<u>we continue to maintain our position that a system-wide DG cap is not necessary</u>**.[17]

[17] Testimony of Mike Byrne, Chief Operating Officer, Michigan Public Service Commission, before the Senate Energy & Technology Committee, July 22, 2020, p. 2 (emphasis added). https://misenate.viebit.com/player.php?hash=Kz6rCPeWYHgu

In this proceeding, Staff witness Cody Matthews similarly recommends that Consumers voluntarily lift what Staff refers to as the "soft cap" for DG customers once that soft cap is met:

> If at any time participation in category 1, category 2, or category 3 of the DG program reaches the soft caps set by PA 295 Sec. 173 (3), Staff recommends that Consumers voluntarily agree to continue to accept applications into the DG program. As shown in Exhibit S-15.0, the Company projects the Category 1 DG program soft cap will be met in October of 2020. As the price of solar panels continues to fall, customer interest in the DG program is expected to continue to increase. The Company's agreement to continue accepting applications beyond the soft caps in PA 295 provides certainty to customers considering whether to install a solar project and removes concern that the program will abruptly close.

8 TR 4816. Staff explains its reasoning for its support for the lifting of the soft cap by noting that, in Staff's opinion, because "Rule C-11.3 is cost-based, and because the legacy net metering tariffs will be closed to new enrollments, limiting aggregate participation to the PA 295 soft caps is no longer necessary." 8 TR 4817. In support of this argument, Staff references UPPCo's Commission-approved 2% soft cap, which is higher than what is included in PA 342. *Id*. Therefore, Staff witness Matthews also recommends that Consumers set a voluntary overall cap of 2%, with individual category caps prorated consistent with Sec. 173(3). 8 TR 4817.

Michigan EIBC/IEI submit that there is voluminous evidentiary support in this record to demonstrate that Consumers should amend its proposed DG tariff and immediately lift or remove the cap on DG participation. Staff has affirmatively stated that a DG tariff that includes the full power supply component of the rate (i.e., one that includes transmission in compensation for outflows) is cost-based and that there are no engineering issues with lifting the cap. In this proceeding, Staff is also supporting increasing the cap, and subsequent Staff legislative testimony argued that the cap should be removed entirely. 8 TR 4817. For all of these reasons, the Commission should find that Consumers should remove or at least increase the soft 1% cap for the DG program, once that soft cap is reached.

4. The Commission Should Adopt A Precise Definition of System And Program Size For Purposes Of The Net Metering And DG Tariff Program Limits, As Well As For The System Size Of Batteries.

Michigan EIBC/IEI witness Douglas Jester testified that the Net Energy Metering/DG program size limit, as provided in Section 173(3) of 2008 PA 295, as amended by 2016 PA 342, is not well defined and is ambiguous. Specifically, Section 173(3) provides, in part, that "An electric utility or alternative electric supplier is not required to allow for a distributed generation program that is greater than 1% . . . " Mr. Jester found that the phrase "a distributed generation program that is greater than" is ambiguous. 8 TR 4500-4501. He noted that since "Consumers Energy is now approaching that limit, as Consumers currently measures it, it is important that the Commission give the limit precise definition. Furthermore, since the limit is subdivided into categories based on customer system size, customer system size also needs to be precisely defined." 8 TR 4501. In part, witness Jester explained that:

> First, system sizes are stated in Section 173(3) of 2008 PA 295 as amended by 2016 PA 342, as follows:
>
> > (a) No more than 0.5% for customers with an eligible electric generator capable of generating 20 kilowatts or less.
> >
> > (b) No more than 0.25% for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 150 kilowatts.
> >
> > (c) No more than 0.25% for customers with a methane digester capable of generating more than 150 kilowatts.
>
> However, for inverter-based systems such as solar photovoltaics, the generation capability of a system can be measured in two places: at the output of direct current from the solar panels to the inverter, which is generally referred to as kWDC, and at the output of alternating current from the inverter to the grid interconnection, which is generally referred to

> as kWAC. As a general practice, inverters are selected such that kWAC can be 20-30% less than kWDC. For purposes of measuring system size against the Net Energy Metering and DG tariff cap, Consumers measures system size in kWDC.[18] MISO measures solar system size in kWAC. To my knowledge, the Commission has not determined how system size is to be measured for purposes of Section 173(3). Since Consumers' "average in-state peak load for the preceding 5 calendar years" is measured in alternating current and any Inflow and Outflow between a customer with distributed generation and Consumers is measured in alternating current, I recommend that the Commission decide that system size and program limits for purposes of Section 173(3) be measured in alternating current.

8 TR 4501-4502. Company witness Keith Troyer agrees with Mr. Jester's recommendation that both the system size and program limits for DG and Net Energy Metering be measured on an AC basis, rather than the Company's current practice of measuring system size on a DC basis, as long as the appropriate information is available. Thus, Mr. Troyer testified on rebuttal that:

> The Company measures the program cap on an AC basis. Therefore, it would be reasonable to measure the system size contributing towards the cap similarly on an AC basis. Historically, the Company has used DC nameplate capacity for determining the system size that contributes towards the cap for net metering customers, therefore it does not have complete, compiled records for the AC system size for all participating customers. The Company estimates that it has AC ratings for 93.5% of the net metering program participants readily available in its records. **Therefore, the Company would agree to measure system size contributing to the cap on an AC basis to the extent that this information is available, but if the AC system size is not readily available for a particular project, the DC system size would be used as a reasonable approximation.**

6 TR 1587-1588 (emphasis added). As the Company has agreed to utilize an AC basis rather than a DC basis, to the extent possible, to measure the DG/Net Energy Metering program cap, the Commission should also adopt this recommendation in its final order in this proceeding.

Witness Jester also testified that the emergence of behind-the-meter battery storage systems in the marketplace has created another source of ambiguity in terms of how its capacity

[18] See Exhibit EIB-2.

to generate electricity should be counted. 8 TR 4502. Specifically, Mr. Jester stated that "Since batteries operate in direct current and flows between a battery and the grid must be done through an inverter, I recommend that battery systems also be sized in alternating current." *Id*. Specifically, Mr. Jester testified that:

> The emergence of behind-the-meter battery storage systems in the marketplace has created another ambiguity. If storage is added to a solar system, how is its capacity to generate electricity to be counted? Since batteries operate in direct current and flows between a battery and the grid must be done through an inverter, I recommend that battery systems also be sized in alternating current. Further, when a battery is integrated with a solar system, it is commonly integrated through the same inverter as the solar system or through circuits that limit the combined Outflow from the solar system and the battery, in alternating current. I therefore recommend that the Commission determine that combined battery and storage system be considered as having the size determined as the alternating current that the system is capable of placing onto the gird.[19]

Mr. Jester thus recommended that the Commission determine that a combined battery and storage system be considered as having the size determined as the AC that the system is capable of placing onto the grid. *Id.*

Company witness Troyer also agrees with witness Jester's recommendations to establish the system size of batteries based on the AC rating, testifying on rebuttal that:

> As Mr. Jester points out there are several configurations for battery storage added to onsite solar generators. If the battery storage and solar generator have electrically separated and dedicated inverters, the aggregate generation would be the sum of the alternating current nameplate ratings at 25°C of the battery storage inverters and the solar generation inverters. However, if the battery storage and solar generation share the same inverters (often referred to as being "DC coupled"), the aggregate

[19] This is similar to the approach recommended by the Interstate Renewable Energy Council in its 2019 Model Interconnection Procedures, available from https://irecusa.org/publications/irec-model-interconnection-procedures-2019/

> generation onsite would be the total of the AC nameplate ratings of the shared inverters.

6 TR 1588. As the Company has agreed to establish the system size of batteries based on the AC rating, Michigan EIBC/IEI submits that the Commission should adopt this recommendation as well.

5. The Commission Should Adopt DG Program Limits Based On The Average System Output Coincident With Consumers' Peak Load.

Michigan EIBC/IEI witness Jester also testified as to the lack of clarity with Section 173(3)'s reference to the "average in-state peak load for the preceding 5 calendar years" for purposes of measuring a 1% soft cap. Per Mr. Jester, this phrase "does not make clear whether the "distributed generation program" is to be measured by the sum of system sizes or by the average output of such systems at the time of the utility's in-state peak load." 8 TR 4502. More specifically, Mr. Jester testified that:

> Since most of the generation in Consumers Net Energy Metering and DG programs is fixed array solar, which produces about 50% of its alternating current size during MISO's peak period, basing the size of "a distributed generation program" on the average output of such systems at the time of the utility's in-state peak load would approximately double the program limits based on system size in kWAC. Since kWAC is about 20-30% smaller than system size in kWDC, a program limit based on average output of participating systems at the time of the utility's in-state peak load would be about 2.5 times larger than one based on summing system sizes measured in kWDC. Average output at the time of Consumers' in-state peak demand could be closely approximated by using MISO's system capacity credit method. **The Commission should consider adopting DG program limits based on average system output coincident with Consumers in-state peak load.**

8 TR 4502 (emphasis added). Company witness Troyer disagrees with witness Jester, stating, in part, that "Mr. Jester is combining certain elements of wholesale market fundamentals with a state statute that makes no reference to market fundamentals associated with the program size."

6 TR 1588. Therefore, witness Troyer states it is not correct to compare the size of the DG systems on the ZRC market fundamentals to a non-market-based program size from statute. *Id*. Yet in rejecting the use of MISO's system capacity credit method to determine the average output at the time of Consumers' in-state peak demand, witness Troyer overlooks that the Company utilizes MISO's capacity credit method – particularly the ZRC calculations – for many other system measurements – most of which are also not specified in statute. Thus, Consumers utilizes ZRC capacity credits for resource adequacy needs for generation plant and renewable energy projects, including the Solar Gardens Voluntary Green Pricing Program (see 6 TR 1945, Table 2; 6 TR 2172), for Planning Reserve Margin Requirements for the Company (see 6 TR 1535), as well as to determine a Capacity Charge (see 6 TR 2173; 6 TR 1536 and 6 TR 1538). To say that the use of the MISO ZRC capacity measurement inappropriately uses "market fundamentals" for a state statute is not only incorrect, but is also inconsistent with the myriad of additional ways that the Company utilizes the ZRC capacity construct for other Company measurements.

For all of these reasons, Michigan EIBC/IEI support witness Jester's recommendation that the Commission find that Section 173(3)'s reference to "average in-state peak load" should utilize MISO's system capacity credit method, and that the DG program limits be based on average system output coincident with Consumers' in-state peak load.

6. The Commission Should Clarify That The Company Will Be Required To Interconnect Customers With Solar PV Systems When The Net Metering/DG Caps Are Met.

As Dr. Sherman testified, there is also great uncertainty for customers moving forward on plans for new solar generation systems as it relates to interconnection of these systems with the Company's distribution network. Specifically, "there is no guarantee given in the tariff sheet that a customer will be provided the right to interconnect a solar PV system once the solar caps are reached." 8 TR 4458-4459. In fact, she stated that there are no protections under Michigan law for small solar DG customers to interconnect outside of the DG program. *Id*.

Consumers does not dispute that there are no Michigan laws requiring interconnection of small solar systems. 6 TR 1585. Federal law, via the Public Utility Regulatory Policies Act of 1978 ("PURPA")[20] provides such a requirement, as Company witness Keith Troyer references. However, under PURPA, those interconnection rights apply only to net metering/DG customers that are certified as qualified facilities ("QF"). 18 C.F.R. Section § 292.303(b). Exhibit EIB-6 (LSS-6). Similarly, despite Company witness Troyer's assertion that the Company is required to interconnect solar generators under the Commission's Interconnection and Net Metering Standards, R 460.620 *et al*., ("Interconnection Standards" or "Rule 620"), those Interconnection Standards only apply to customers seeking interconnection of net metering or DG projects. This is an important requirement that witness Troyer conveniently overlooks.

Specifically, witness Troyer cites no specific statutory or Commission rule for the position that a utility must provide interconnection to a customer <u>outside of a net metering or DG program</u>. While he claims that the Company's interconnection process "applies to all interconnecting facilities," pursuant to R 460.620, and that the "right to interconnect is, and will continue to be, independent of the applicant's desire or ability to participate in any particular program or contract,"[21] a plain reading of R 460.620 ("Rule 20") shows otherwise.

The Commission's Interconnection Standards were originally promulgated in 2009 in response to 2008 Public Act 295's ("PA 295") requirements for Net Energy Metering. 2016 PA 342, amended PA 295 including MCL 460.1173(1) ("Section 173"), and provides that: "The

[20] Public Utility Regulatory Policies Act of 1978 ("PURPA"), 16 U.S.C. § 824a-3.
[21] 6 TR 1586.

commission shall establish a distributed generation program by order issued not later than 90 days after the effective date of the 2016 act that amended this section. The commission may promulgate rules the commission considers necessary to implement this program."[22]

The current Interconnection Standards in effect only apply to a "net metering" "program" or "project." Thus, the "Applicant" for the interconnection request "means the legally responsible person applying to an electric utility to interconnect a <u>project</u> with the electric utility's distribution system or a person applying for <u>a net metering program</u>. An applicant shall be a customer of an electric utility and may be a customer of an alternative electric supplier. R 460.601a(c) (emphasis added). This is the "Applicant" that is referenced in Rule 20(1). A "Project" means "electric generating equipment and associated facilities that are not owned or operated by an electric utility," Rule 460.601b(i), or otherwise defined as specified "projects" pursuant to Rule 460.601a (f)-(j). There is nothing in the Interconnection Standards as a whole, nor anything specific in Rule 20, that specifies or gives any indication that the Interconnection Standards apply to any "applicant" seeking an interconnection outside of a net metering "project" or "program." Therefore, while witness Troyer expresses his opinion that an interconnection will still be required for any customer seeking to interconnect solar generation outside of a net metering or DG program, he fails to cite any specific regulatory provision that would mandate such a requirement. Quite simply, there is none.

Once the Net Energy Metering/DG cap is met, Consumers states that it will *not* be allowing customers to interconnect net metering or distributed generation for the purpose of participating in a Net Energy Metering or DG program. Given that there are no statutory laws or rules requiring interconnections outside of a Net Energy Metering or DG program, Dr. Sherman

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[22] The Commission Staff has been leading stakeholder workgroup sessions since December 2018, to promulgate new interconnection standards to comply, in part, with Section 173.

has raised a serious loophole that will create great uncertainty in future customer-owned solar PV systems. The lack of Commission orders or rules that require interconnection outside of an established program cannot, and should not, be viewed as "unfounded" by the Company, and certainly should not be "rejected" by the Commission, per the Company's requests.

Given that the Company has attempted to give assurances that it will interconnect any customer with a solar PV system outside of the Net Energy Metering/DG program, the Company should have no opposition to the Commission affirmatively recognizing this requirement, for the benefit of self-generating customers, in its final order in this proceeding.

7. Proposed Rule C11.1 Must Either Be Rejected By The Commission As Non-Compliant With PURPA, Or Significantly Amended To Ensure Compliance.

Company witness Hubert W. Miller testified that the Company proposes that once it meets a 1% cap for the DG program, an eligible generation customer will not be able to enroll in the DG program, but can choose one of two contractual options to receive compensation for excess power the customer puts back on the grid: (1) the PURPA Standard Offer contract rate, via the Company's Rule C18, Distributed Generation Program, or Net Metering Program, or (2) through an energy only contract at the wholesale market price of energy (MISO's LMP), described in proposed Rule C11.1, *Self-Generation*. 4 TR 580. Rule C11.1 would be available to customers who meet the Federal Energy Regulatory Commission's ("FERC") criteria for a QF, but elect not to participate in the Company's Standard Offer under Rule C18.

As Rule C11.1 is the only method by which a PURPA qualified facility can sell energy "as available" to Consumers, it must comply with PURPA and its associated rules. Rule C11.1 would violate PURPA in that it denies that Consumers has an obligation to purchase energy "as available" from a QF, as well as a requirement that a QF enter into a written contract with the Company, either a standard offer contract, or an energy-only contract. To comply with PURPA, the Commission should either reject Rule C11.1, or require that Consumers modify the language contained therein in order to reflect Consumers' obligation to purchase energy from a QF "as available."

In particular, on July 16, 2020, the FERC issued Order No. 872,[23] ("Order No. 872") adopting major revisions to its regulations implementing the avoided cost rate setting and other requirements of PURPA. Of importance for purposes of Consumers' proposed Rule C11.1, while FERC made changes in the types of "rates" that a state commission can implement for purposes of energy and capacity avoided costs, FERC maintained the basic structure of 18 CFR 304(d) that provides that purchases can be either "as available" or pursuant to a legally enforceable obligation ("LEO"). The latter is often referred to as contractual, or fixed energy or capacity rates, which do not vary over the term of the contract or LEO. These types of fixed contracts are most attractive to larger QF developers that generally produce electricity to sell into the market and rely on a fixed revenue stream for financing. Rates for capacity are generally fixed at the time of contract or LEO. 18 CFR 304(d)(2).

However, other QFs, like cogeneration facilities or small DG systems, might only sell into the market when they have excess energy and will take the prevailing price at the time of sale. This rate is referred to as an "as available" energy rate and is variable. 18 CFR 304(d)(1). In part, FERC made changes to the "as available" QF energy rates paid by electric utilities located in Regional Transmission Organization and Independent System Operator ("RTO/ISO") markets. These rates may now be based on the market's LMP, or similar energy price derived by the market, in effect at the time the energy is delivered. In such cases, there

[23] *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 172 FERC ¶ 61,041 (July 16, 2020).

would be a rebuttable presumption rather than a per se rule that LMPs in RTO/ISOs can reflect a purchasing electric utility's avoided energy costs. FERC Order 872, P. 201.

FERC's new PURPA rules maintained the requirement that for QFs with a design capacity of 100 kW or less, standard rates for purchases from these QFs "shall be put into effect." 18 CFR 304(c)(1). § 292.304 (d) was revised as follows:

> (1) Each qualifying facility shall have the option either:
>
> (i) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the electric utility's avoided cost for energy calculated at the time of delivery; or
>
> (ii) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, except as provided in subsection (d)(2) below, be based on either:
>
> (A) The avoided costs calculated at the time of delivery; or
>
> (B) The avoided costs calculated at the time the obligation is incurred.
>
> (iii) The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery.
>
> (2) Notwithstanding paragraph (d)(1)(ii)(B), a state regulatory authority or nonregulated electric utility may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery.

Thus, under FERC's new PURPA rules, standardized "rates" on an "as available" basis must still be in effect for QFs 100 kW or less. Consumers offers two fixed, or contractual rates – either through its Standard Offer PURPA contract, or its proposed new Rule C11.1. However, neither Rule C18, nor proposed Rule C11.1, provides QFs with the option of selling excess to the Company on an "as available" basis, without the need of being locked into a contract. As Michigan EIBC/IEI witness Douglas Jester found:

> Standard Offer purchases under Rule C18 may satisfy 18 C.F.R. § 292.304(d)(2) but does not provide a qualifying facility the opportunity to provide energy "as available" as required by 18 C.F.R. § 292.304(d)(1). On its face, the proposed Rule C11.1 denies that Consumers has an obligation to purchase energy "as available" from a qualifying facility in that "[t]he Company has the right to refuse to contract for the purchase of energy." And "[s]ales of energy to the Company under this provision shall require a written contract with a minimum term of one year." Thus, at a minimum, the Commission must require Consumers to modify the language of proposed Rule C11.1 to reflect that Consumers is obligated to purchase energy on an "as available" basis from any qualifying facility.
>
> A requirement to enter a written contract of any duration is also inconsistent with the requirement to provide "standard rates" for qualifying facilities with a design capacity less than 100 kW. If rates are indeed standard, there is nothing to be provided by contract and the requirement for a contract simply adds transactional friction, costs, and delay to what FERC clearly intended to be a simple process.

8 TR 4491.

Commission Staff similarly expressed concerns with Consumers' proposed C11.1 Rule, testifying that:

> Because the DG program will be closed, customers choosing to install solar must sign a contract with the Company, which has much different pricing and contract language than the net metering and DG program contracts have. For example, the standard offer contract includes an early termination security provision that is not included in the DG program. Additionally, the standard offer contract process is administratively inefficient for the Company, participating customer, and the Commission when compared to simply applying for service under the DG program. All standard offer contracts must be approved by the Commission.

8 TR 4815.

Michigan EIBC/IEI agrees with witness Jester that Consumers' proposed Rule C11.1 violates FERC's PURPA requirements that require Consumers to purchase energy from QFs "as available." The fact that Consumers requires a contract for the energy-only sales, and that the Company may "refuse to contract for the purchase of energy," is a clear violation of PURPA. Moreover, as JCEO witness Kenworthy notes, Rule C18, the Commission-approved Standard Offer tariff for Consumers, which allows QFs at or below 150 kW to receive a power purchase agreement based on the Company's full avoided cost, was "intended to be applicable to the interactions between the Company and developers of large facilities." 8 TR 4178. It did not take into account small distributed generation customers.

Therefore, Rule C11.1 must be rejected by the Commission, or Consumers should be ordered to change the proposed rule to comply with FERC's Order 872. In this regard, Michigan EIBC/IEI supports witness Jester's recommendations that the Commission require Consumers to modify the language of proposed Rule C11.1 to reflect that Consumers is obligated to purchase energy on an "as available" basis from any qualifying facility, and that Consumers eliminate the requirement of a written contract for "as available" PURPA sales. 8 TR 4491. Michigan EIBC/IEI also agrees with JCEO witness Kenworthy's recommendation that the energy purchase *rate* in Rule C11.1 "should be the same rate as the Company's PURPA Standard Offer set in *Rule C18 – Standard Offer – Purchased Power*. However, this proposed new rate would not be needed at all if the Company offers the DG Program to customers beyond the 1% cap." 8 TR 4178.

IV. THE COMMISSION SHOULD REQUIRE CONSUMERS TO MAKE CERTAIN ADJUSTMENTS TO ITS STANDBY RATE TO ENSURE THAT THE RATE IS REASONABLE AND COST-BASED.

Consumers seeks a change in the current allocation of distribution costs as they relate to its General Service Self Generation Rate GSG-2 ("Standby" or "GSG-2"). Specifically, Consumers' witness Josnelly C. Aponte testified that "the current allocation of distribution costs based on historic class peak does not appropriately reflect the investments in the distribution assets that are ready to serve stand by customers. Therefore, the Company is proposing to utilize the contracted demand of GSG-2 customers, adjusted by a coincidence factor, in place of the average historic class peak, which is described in Exhibit A-21 (JCA-7), Standby Study by the Brattle Group ("Brattle Group"), page 8. For the Test Year COSS – Version 2, the Company used the coincidence factor of 45%, which was calculated using 2018 historic data, considering that the peak of total customer demand for this group of customers increased more than 900% from 2016 to 2018." 5 TR 820-821. Michigan EIBC/IEI opposes Consumers' proposed changes of the current methodology for the allocation of distribution costs. Instead, Michigan EIBC/IEI support specified changes to the GSG-2 rate as presented by witness Douglas Jester and as enumerated below.

A. Production Cost Allocation To GSG-2 Standby Customers Should Be Based On The Same Cost of Service Calculation As Provided For An LTILRR Customer, But With A 4CP Demand Allocator.

While Consumers does not propose a change in the GSG-2 tariff as it relates to production costs, as witness Jester explains, the Company utilizes a different calculation of the costs of standby service for its proposed Long Term Industrial Load Retention Rate ("LTILRR") as opposed to the tariff for GSG-2. As Mr. Jester detailed, the tariff for GSG-2 is presented by Consumers in

Exhibit A-16 (RLB-2), which shows that only the per-unit rates in the tariff for delivery services are proposed to be changed. As summarized in that tariff:

> **"**For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition, capacity charges will be assessed monthly, calculated using the highest 15-minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month."[24]

As explained by witness Jester, this new cost of service design (i.e., "Version 2") allocates <u>greater costs to demand</u>, and less to energy than does current practice. These adjustments thus provide a further deviation from a market-based rate. Thus, Mr. Jester testified that:

> The essence of Miller's testimony is that in developing rate design revenue as compared to cost of service study revenue responsibility, he transferred certain capacity revenue responsibilities from rate schedule GSG-2 to other classes, transferred certain energy revenue responsibilities from other rate schedules, and that the net change in production revenue responsibility was small so that Consumers did not propose to change the tariff in this case. He made those transfers to "reflect the difference between the market cost of production capacity collected from large standby customers taking service under rate GSG-2 and the embedded cost of capacity allocated to them in the COSS." He further states that "[t]wo similar adjustments … are made for both production energy and transmission costs." This analysis was in the context of Consumers' proposal to use Version 2 cost of service study to set revenue responsibility in this case. Version 2 allocates greater costs to demand and less to energy than does current practice. These adjustments illustrate that Version 1 of the cost of service study is closer to market rates than Version 2.

Comparatively, however, Mr. Jester shows how the LTILRR cost of service design seeks to essentially mimic and rely upon the MISO market design in order to produce a much favorable

[24] Exhibit A-16 (RLB-2), pages 113 through 115.

rate. This calculation, in Mr. Jester's opinion, is the "correct calculation of the costs of standby service." Company witness Michael P. Kelly describes the basis on which Consumers and Hemlock Semiconductor Operations LLC ("HSC") established the cost of backup service for HSC's use of the designated Zeeland plant as its power supply source pursuant to the LTILRR:

> **"Q. What adjustments are needed to account** 1 **for MISO resource requirements?**
>
> A. Because the Annual Forecasted Capacity election is based upon the demand at the customer's meter, the LTILR rate accounts for the adjustments the Company makes to ensure MISO resource requirements are met for planning purposes. To arrive at a rate and capacity that includes these resource requirements, the net demonstrated generating capability ("NDC") of the designated resource is first adjusted by the designated resource's equivalent forced outage rate ("EFORd") to get to an equivalent Zonal Resource Credit ("ZRC"). The ZRC is then adjusted by the MISO Planning Reserve Margin Requirement ("PRMR") to come to an equivalent PRMR Capacity. This figure is then adjusted to account for line losses to develop a Loss Adjusted Capacity. Finally, the Loss Adjusted Capacity is updated to account for the customer's coincidence with the MISO peak to ensure MISO resource requirements are accounted for in setting the LTILR Capacity Charge.
>
> Formulas for determining capacity in setting the Capacity Charge are as follows:
>
> 1. ZRC = NDC * (1-EFORd)
> 2. PRMR Capacity = ZRC / (1-PRMR)
> 3. Loss Adj. Capacity = PRMR Capacity * (1–Customer Losses)
> 4. Resource Requirement Capacity = Loss Adj. Capacity / Customer Coincidence "

6 TR 2172-2173. Mr. Jester explained that "the principle behind this method is that within MISO, all capacity resources back up all capacity resources. In the case of HSC, having selected that its designated power source will be the Zeeland plant, the Zeeland plant is backed up by the planning reserve margin of MISO's resource adequacy construct. In the case of a customer with self-generation under the GSG-2 tariff, the standby contract amount is the capacity of the customer's designated generator that is backed up by the planning reserve margin." 8 TR 4506-

4507. Therefore, in Mr. Jester's opinion the correct inclusion of standby service in the cost of service study for GSG-2 standby customers should be obtained by using the Resource Requirement Capacity (formula 4) above, that Consumers uses for it LTILRR standby customer. *Id*.

Witness Jester cautions, however, that because the cost of service study uses 4CP demand to allocate capacity costs, the Customer Coincidence should be calculated using standby customer 4CP rather than the customer's peak load. Thus, he states that:

> It is important that the rate design continue to use either a monthly charge pro-rationed by the number of peak-days of usage or a daily charge on demand to collect the required capacity revenue, because that rate design incents reliable operations of behind-the-meter generation. However, rather than using the "the highest contracted capacity purchased by the Company in that month" to set the rate that applies to that pro-rationed monthly demand, the rate should be established to obtain the required revenue determined in the cost of service study as described by witness Kelly.

8 TR 4507.

Consumers' witness Aponte disagrees that the Zeeland Combined Cycle Gas Turbine is the power supply source for the customer under the LTILRR, and further states that "Act 348 provides eligible large industrial customers with the ability to receive an electricity rate which is based on the cost of a designated power supply resource. The Company's proposed rate to provide this option is the LTILRR. This means that the Company used a designated power supply resource as the cost basis. It does not mean that the designated power supply resource meets the capacity and energy needs of the customer under the LTILRR. This is different from a customer with self-generation whose energy and capacity needs are in part or fully met by its self-generation." 5 TR 856-857. But in seeking the rejection of Mr. Jester's suggested production cost rate, witness Aponte does not explain why GSD-2 customers, in general, should be allocated far greater production demand-based costs than the more favorable market-based costs it assigns to the LTILR customer. She also does not respond to Mr. Jester's recommendation that any cost of service study for GSG-2 customers use 4CP demand to allocate capacity costs, rather than the customer's peak load.

For all of these reasons, Michigan EIBC/IEI support witness Jester's recommendation that production cost allocation to GSG-2 standby customers should be based on the same cost of service and calculation as provided for an LTILRR customer, but with a 4CP demand allocator.

B. Consumers' Proposal To Allocate Distribution Costs To Standby Customers Based On Contracted Demand Should Be Rejected.

Consumers proposes a change to the allocation of distribution costs to standby customers – from one based upon an average historic class peak, to one based upon contracted demand. 5 TR 820. This recommendation derives from the standby study that Consumers commissioned the Brattle Group to perform as part of its settlement agreement in its last electric rate case, Case No. U-20134 ("Standby Study"). Brattle Group Standby Study, Exhibit A-21 (JCA-7). Specifically, the settlement agreement in Case No. U-20134 provided, in part, that:

> Consumers Energy agrees that, in its next general rate case, the Company will provide a study analyzing the issue of the cost to serve customers who take standby service. The study will focus on behind-the meter generation capacity that exceeds 550 kw. The study will review both the actual demands that standby customers place on the system as well as the cost of the investments that are in place to provide standby service."[25]

As witness Jester notes, this provision of the Settlement Agreement was partly in response to his testimony and the positions taken by Michigan EIBC in that case. 8 TR 4507. Michigan EIBC/IEI submit that Consumers' proposed change in the distribution costs to standby customers should be rejected, due to the fact that the underlying Brattle Group Standby Study was not

[25] Case No. U-20134 Settlement Agreement approved in Order of January 9, 2019 ("Settlement Agreement").

responsive to the agreed-upon settlement to conduct a standby rate study, as well as the fact that it does not properly reflect the distribution cost of service for standby customers.

As an initial matter, as Mr. Jester found, the Brattle Group Standby Study did not fully comply with the review that Consumers agreed to conduct for standby service. Namely, while it did include an examination of "the actual demands that standby customers place on the system," it did not carefully examine the "cost of the investments that are in place to provide standby service." 8 TR 4509. Witness Jester listed several ways in which the study failed to provide this level of examination, including the fact that the Brattle Group does not present any analysis of what particular distribution system investments have been made by Consumers in order to meet the distribution capacity requirements of standby customers.

Instead, as Mr. Jester found, the authors argue generically that "When a Standby customer is added to the system, Consumers planners determine whether a network upgrade is required to accommodate the new customer based on the customer's contracted demand." However, Mr. Jester correctly notes that "This analysis should be true as a matter of good engineering practice." 8 TR 4508-4509. Mr. Jester found that the Brattle Group also neglects the potential requirements of a customer Contribution in Aid of Construction ("CIAC") for line extensions as provided in Rule C6 of Consumers electric tariff when discussing customer responsibility for system upgrades. *Id.*

Perhaps the greatest flaw in the Brattle Group's Standby Study, per Mr. Jester, is the manner in which the Brattle Group computes and then assigns demand to standby customers. Thus, Mr. Jester testified that:

> The Brattle Group then discuss that "[a] key engineering consideration in determining Standby costs is whether: the Consumers distribution system is planned to *simultaneously* provide the contracted demand of *all* Standby

> customers, *holding constant all other classes demand*, or Consumers takes into account the likely demand diversity among the Standby customers when planning its system."[26] It is on this basis that Brattle Group and Consumers Energy conclude that the correct method to allocate costs to standby customers is to consider demand diversity applied to contract demands. That is, that the total additions to Consumers distribution system are to consider that total contract demand is to be served and that diversity amongst standby customers mitigates that capacity requirement. <u>However, they compute demand diversity with respect to actual demands and then apply that to contract demands to assign demand to standby customers for purposes of the cost of service study.[27]</u> Consumers applies a coincidence factor of about 35% to a contract demand total of 161,370 kW to assign cost of service demand of 56,494 kw rather than using the observed average annual class peak demand of 17,253 or applying a coincidence factor of actual class peaks to total class contract demand, which would have led to a coincidence factor of about 10.6%. If this coincidence factor is applied to the 2017 contract demand of 211,403 kW, it would have led to a cost of service demand of 22,602 kW.

8 TR 4509-4510 (emphasis added). The method of computation and then assignment of demand is where witness Jester believes that "Brattle Group and Consumers depart from reality." 8 TR 4510. Thus, Mr. Jester explains that:

> No doubt, standby customer interconnection planning is based on contract demand of each individual standby customer. However, standby customers are not co-located with one another. Rather, these few customers are located in scattered locations within Consumers distribution system and they share distribution facilities principally with non-standby customers (and not principally with each other). <u>Thus, the relevant diversity of demand for standby customers is not with other standby customers but with other customers at the same voltage levels as the standby customers</u>. Although the data to assess coincidence with other customers at the same voltage level is not easily determined in this case, Exhibit A-21 (JCA-7) does provide the data to evaluate 4CP actual demand (not with respect to contract demand) coincidence with Consumers total system.60 For the months of June through September 2018, the Standby customer class peak coincident with Consumers monthly system peak was 27,722 kW (for a 1 monthly average of 6930 kW) while customer non-coincident monthly peaks totaled 149,960 kW, which is a system coincidence factor of about 18.5% with respect to actual customer demands.

[26] U-20797, Exhibit A-21 (JCA-7), p. 13.
[27] *Id.*, page 8 and Direct testimony of Josnelly C. Aponte, page 21 lines 19-22

8 TR 5510-5511 (emphasis added). Witness Jester notes that for "standby customers interspersed with customers in other rate schedules, it is particularly inappropriate that splitting standby customers from the rest of the class(es) to which they would belong leads to a higher cost allocation to standby customers than would be their share of cost allocation based on being combined with those other class(es)." *Id.*

Staff also expresses concerns with Consumers' attempts to separate GSG-2 standby customers into their own class. Staff witness Nicholas M. Revere thus testified that:

> Currently standby customers are treated as members of the same class as other Primary customers for the purpose of distribution rate design. The Company has not shown that the coincidence of standby customers differs significantly from those other customers such that they should no longer be considered as taking distribution service in a similar enough manner to other customers in the class to merit their own class. The Company fails to note that the same study shows that, under the current method, the Company could be considered to be over-collecting distribution revenue from GSG-2 customers3. In Staff's opinion, based on the foregoing, the evidence does not merit consideration of GSG-2 customers as a separate class for distribution purposes, so a potential "under-collection" is within the acceptable variation within the class.

7 TR 2916.

Finally, to further illustrate the extent and nature of the type of study that Consumers and the Brattle Group should have conducted regarding the "cost of the investments that are in place to provide standby service," witness Jester points to Exhibit EIB-9 (DBJ-2). Consumers provided a response to that discovery request that asked for information about the specific distribution system investments associated with each of the standby rate customers analyzed in the Brattle Group study:

	20697-MEIBC-CE-854
	Attachment 1
Identifier	Dedicated Distribution Facilities
1	0.7 miles of 46 kV line, Metering, Telemetry/Communcation, Protective Relaying
2	Metering, Telemetry/Communication
3	None
4	Crossarm w/ fuses, Overhead PT/CT metering cluster, Underground primary cable to customer switch
5	Metering, Telemetry/Communcation
6	Metering, Telemetry/Communcation
7	0.59 miles of 46 kV line, Metering, Telemetry/Communication
8	2.12 miles of 46 kV line, 46 kV line exit and breaker, Metering, Telemetry/Communication.
9	Metering
10	0.24 miles of 46 kV line, dedicated substation including 12/16/20 MVA 46/13.8 kV LTC transformer, 46 kV switch and fuses, 13.8 kV switches, fuses and station power. Metering equipment.
11	Metering
12	4 miles of 138 kV underground circuits, dedicated 138 kV riser station including switches, dedicated substation including two 50/67/83 MVA 138:13.8kV LTC transformers, 138 kV switches and circuit switchers, 13.8 kV breakers, switches, station power, metering, relays, power quality monitors.
13	Metering
14	0.05 miles of 46 kV line, Metering, Telemetry/Communcation, Protective Relaying
15	0.7 miles of 46 kV line, dedicated substation including 12/16/20 MVA 46:24.9 kV transformer, 46 kV switch and fuses, 24.9 kV switches, voltage regulators and station power transformers, metering and power quality monitors.

Witness Jester notes that while these data do not provide investment costs, they do illustrate that for some standby customers, there is a significant amount of dedicated infrastructure and for others there is nothing more than metering. 8 TR 4511. Therefore, Mr. Jester concluded that "While these data do not complete a study of the 'cost of the investments that are in place to provide standby service,' they do suggest that an answer to that question requires specific examination of each customer. Moreover, some significant portion of these dedicated facilities should have been paid for by the customers at time of interconnection and may not be in Consumers' embedded costs." *Id.*

Based on the foregoing, Michigan EIBC/IEI support witness Jester's recommendation that Consumers' proposal to allocate distribution costs to standby customers based on contracted demand be rejected. Furthermore, due to the fact that Consumers and the Brattle Group did not fully comply with the agreed-upon parameters for the standby study, the Commission should require Consumers to complete the study of standby customer distribution costs ordered in U-20134 by assessing Consumers embedded distribution system costs dedicated to, or caused by, particular standby customers, in order to determine what distribution system costs should be allocated based on contract demand and on actual demand. 8 TR 4516.

1. Distribution Cost Allocation To Standby Customers Should Be Based On The Coincidence Factor Of Actual Customer Demands With Consumers' System Peak, As Measured At The Time Of 4CP.

In order to provide an approximation of the diversity of standby customer demand with the demand of all other distribution customers, witness Jester recommends that the Commission order that the allocation of distribution system costs for standby customers in this case be based on the coincidence factor of actual customer demands with Consumers system peak as measured at the time of 4CP. 8 TR 4511. In Mr. Jester's opinion, "This provides an approximation of the diversity of standby customer demand with the demand of all other distribution customers, which is the way that upgrades, if any, to shared facilities should have been engineered for standby customer distribution paths." *Id.* Michigan EIBC/IEI supports this recommendation as well.

V. CONSUMERS ENERGY'S PROPOSED ELECTRIC VEHICLE CHARGING PROGRAM REQUESTS, WITH TARGETED ENHANCEMENTS, SHOULD BE APPROVED.

A. Consumers' PowerMIFleet Pilot Program Should Be Accepted By The Commission With Targeted Enhancements.

Michigan EIBC/IEI recommends that the Commission approve Consumers' proposed 3-year pilot program entitled, "PowerMIFleet" ("PowerMIFleet" or the "Program"), with the following recommendations contained herein.

As Consumers' witness Sarah R. Nielsen testified, the PowerMIFleet will target various types of fleets, including light, medium and heavy-duty vehicles. The Program will enable Consumers and other stakeholders to better understand the charging needs of fleet owners and operators and the consequent issues in grid integration, including distribution system infrastructure, charging infrastructure installation and management of charging throughput and scheduling. Michigan EIBC/IEI witness Douglas Jester has had extensive experience over the past 10 years participating in workgroup meetings with Consumers Energy and other interested parties regarding electric vehicle charging infrastructure and rate design. He has review and analyzed Consumers' initial charging infrastructure pilot program, PowerMIDrive, and on behalf of Michigan EIBC, suggested targeted enhancements to that pilot program to ensure its success. Similarly, witness Jester supports approval of the PowerMIFleet pilot project, especially if Consumers accepts his recommendations for improvement of the Project. 8 TR 4481.

Overall, witness Jester found that Consumers' witness Sarah R. Nielsen presented a strong case for engaging in an electric vehicle charging pilot by demonstrating that:

- There are existing and announced electric vehicles suitable for use in the major types of fleets.

- There is articulated interest in electrification by certain fleet owners, including in Michigan and Consumers' service territory.

- There are benefits to be gained for society, for fleet owners, and for Consumers' other customers through fleet electrification.

- Knowledge of electric vehicle operation and charging infrastructure are key market barriers for fleet owner adoption of electric vehicles.

- Initial investment costs for charging infrastructure are a significant barrier for fleet owners, especially given their uncertainty about whether they are making the right investments.

8 TR 4474-4475. Furthermore, witness Jester testified, in part, that the PowerMIFleet Program was "well-structure to achieve its objectives," for the most part, due to the fact that:

> It is built on Consumers' experience in the PowerMiDrive pilot project, and includes Technical Development in support of the program, Education and Outreach to fleet owners and other fleet charging stakeholders, support for fleet charging infrastructure within the scope of the pilot project, and specific trails of workplace demand response and bi-directional power flow between school busses and the grid.

Id. After a full examination of the PowerMIFleet Program, witness Jester recommended key areas that should receive the Commission's approval, and suggested other areas that could benefit from improvement, as explained in more detail below.

1. The Commission Should Support The Company's Request For Deferred Accounting Authority For the PowerMIFleet Pilot Program.

Company witness Daniel L. Harry testified that, if approved, the PowerMIFleet Program would result in a deferred asset until the EV Program costs are fully collected, and thus the Company requests approval to recognize a regulatory asset to record these deferred amounts. 6 TR 1869. Specifically, the Company requests that the Commission: (i) authorize the recognition of a regulatory asset to recognize deferred EV Program costs; (ii) authorize the amortization of deferred EV Program costs over five years beginning the year after the costs are incurred; (iii) following a review of incurred costs in rate cases, include recovery of the resulting amortization expense in rates; and (iv) include the deferred net unamortized balance of EV Program costs in rate base." 6 TR 1870.

Michigan EIBC/IEI supports approval of the proposed deferred accounting authority. The manner Consumers has proposed for deferred accounting authority is certainly preferable over Consumers' alternative recovery approach, which would include utilizing projected test year program costs in rates for recovery. 6 TR 1870.

As witness Jester stated, deferred accounting authority is the "best way to provide cost recovery while dealing with the uncertainty about the pace of expenditures in the program. Including projected costs in current rates creates a real risk of revenue exceeding actual cost, and setting a conservative level of spending so as to avoid that risk will discourage Consumers from executing the project in excess of the authorized level of cost recovery." 8 TR 4481.

For all of these reasons, Consumers' requested deferred regulatory approach, including the specific requested accounting approvals, should be adopted by the Commission.

2. The Commission Should Allow Consumers Flexibility In Setting Rebates.

As Company witness Nielsen explains, the PowerMIFleet Program is proposed as rebate offerings under a "make-ready" model, similar to PowerMIDrive, rather than by Company ownership. In this manner, rebates for Level 2 and DCFC charging can be applied to costs associated with supply infrastructure, such as panel and wiring, as well as the charger equipment itself. 8 TR 2305. Rebate and make-ready terms include: 1) an existing Consumers Energy electric customer, 2) a choice from a Company-approved list of EV chargers which meet the minimum standards required to carry out data collection and demand response, 3) share charging data with the Company, and 4) enable the capacity for the Company to conduct DR testing and/or programs during the three-year pilot Program; individual event testing would be an opt-out option for users. *Id.*

Consumers' witness Nielsen agrees with witness Jester that rebate flexibility, as with PowerMIDrive, should be part of the program to encourage participation by underrepresented sectors. In particular, Ms. Nielsen stated that "the flexibility to go beyond the three-year timeline originally proposed while staying within the final approved budget, could also help achieve program inclusion goals." 6 TR 2332.

Michigan EIBC/IEI agree with witness Jester's support of the Company's request to structure the Program pursuant to a rebate and make-ready model, noting that the Commission should allow Consumers flexibility to adjust rebates and other aspects of the Program (i.e., charging level requirements and limited ownership opportunities) so as to achieve the necessary experiences, within the Program's overall budget. 8 TR 4477.

3. The Commission Should Require Consumers To Make An Effort To Expand Vehicle Options For the Program.

Consumers identifies a number of potential fleet applications as likely to be addressed in PowerMIFleet. Michigan EIBC/IEI witness Douglas Jester testified that because fleets are diverse and are likely to present a variety of different issues and challenges, Consumers should commit to an affirmative effort to include certain types of fleets in the program. In Mr. Jester's opinion, based on the types of vehicles that are or are projected to be available and the differences in fleet use patterns, one, if not more, of each of the following fleet types should be included in the Program: municipal transit buses; passenger vans; school buses; pooled (shared) automobiles or light-duty vehicles; assigned (single-driver) automobiles or light-duty vehicles with a shared "base"; local delivery trucks; municipal public-works vehicles (e.g., refuse trucks, street sweepers, pickups, etc.); and drayage trucks (i.e. off-road equipment). 8 TR 4476-4477.

Mr. Jester also testified that in addition to the above-stated categories, it is notable that Lyft, a major networked mobility provider, has recently announced that it will achieve 100%

electric vehicles on its platform by 2030,[28] which Mr. Jester believes will likely have unique fleet charging requirements given that it is a dispersed fleet that depends for revenue on being ready to respond immediately to customer trip requests. 8 TR 4477.

Witness Jester also recommended that if medium-duty and heavy-duty freight vehicles become timely available, Consumers should seek an opportunity to engage with such a fleet. However, he predicts that the needs of such a fleet will require a network of chargers like the DC Fast Charging network for passenger vehicles that is being developed through PowerMIDrive and will therefore need to be addressed through a future pilot project (i.e., "PowerMIFreight"). 8 TR 4477-4478.

Company witness Nielsen agrees, in part, with Mr. Jester's recommendations, noting that "The goal of the PowerMIFleet Program is to include a wide variety of participants but market participation in each sector as suggested cannot be guaranteed, especially given current economic conditions due to the COVID-19 pandemic." 6 TR 2332.

Michigan EIBC/IEI supports witness Jester's recommendation to include additional fleet types in the PowerMIFleet Program. This was not a suggested mandate, but rather suggested as a means to ensure that Consumers commits to keeping an open mind should any of these fleets become available for inclusion in the Program. For all of these reasons, Michigan EIBC/IEI supports witness Jester's recommendations for future inclusion of additional fleet options.

4. The Commission Should Require Consumers To Identify And Adopt Certain Relevant Open Standards And Protocols For Electric Vehicle And Fleet Charging And Report On That Effort To The Commission As Part Of Its Learning Process.

[28] Lyft: Leading The Transition to Zero Emissions, June 17, 2020: https://www.lyft.com/blog/posts/leading-the-transition-to-zero-emissions

Michigan EIBC/IEI witness Jester testified to the importance of the PowerMIFleet Program including adoption and adherence to relevant industry open standards and protocols. In part, Mr. Jester stated that:

> Markets, especially for technical products and services, depend on open standards to achieve interoperability, economies of scale, and transactional efficiency. <u>Consumers should make an explicit effort to identify and adopt the relevant open standards and protocols and should report on that effort to the Commission as part of its learning process</u>. As examples, demand response should likely use the OpenADR standard,[29] charging system management will be facilitated by use of the Open Charge Point Protocol,[30]and integration with fleet management systems will be facilitated by adherence to open interoperability standards using extensible markup language.[31] Notwithstanding any reluctance the Commission may have about selecting and requiring any particular standards, <u>the Commission can and should require Consumers to give serious consideration to such standards</u> both to encourage development of an efficient marketplace and to avoid stranding assets that do not adhere to standards.

8 TR 4479 (emphasis added).

Consumers' witness Nielsen supports requesting information related to open standard protocols as part of the Request for Qualification process for pre-approved chargers, noting that some EV Supply Equipment ("EVSE") for specific fleet use cases might not permit it. 6 TR 2234. However, Ms. Nielson asserts that the Company does not recommend that open standards be mandated by the Commission at this time, and does not support inclusion of defined mandatory information in the annual report at this time, noting that "flexibility to determine, at the end of the one-year mark of the pilot program, what information is meaningful for the report," similar to the annual report for the PowerMIDrive Program. *Id.*

Michigan EIBC/IEI appreciate the Company's need for flexibility in reporting. However, again, contrary to witness Nielsen's reference, Mr. Jester was not recommending that the

[29] *See* https://www.openadr.org/ ("EVConnect").
[30] See https://www.openchargealliance.org/protocols/ocpp-16/
[31] *See* https://www.w3.org/auto/events/data-ws-2019/report.html

Commission issue a "mandate" for open standard protocols, but rather should "make an explicit effort to identify and adopt the relevant open standards and protocols," "report on that effort" and "give serious consideration" to the inclusion of such standards. In this nascent industry, open standards and protocols are needed, in part, to ensure that customers are not locked into one particular provider. As explained in EVConnect, referenced by witness Jester, if a network is truly open, the customer should be able to switch network providers without replacing their charging stations when their contract is up.[32] This is similar to the "universal network" that cell phone providers must provide. In this regard, Mr. Jester cautioned Consumers "that the fleet charging market is different than the personal charging market and requires different infrastructure solutions. Thus, while consumers should not ignore its partners from PowerMiDrive when developing PowerMiFleet, it also should be open to engaging new and different partners for PowerMiFleet." 8 TR 4481.

For all of these reasons, Michigan EIBC/IEI recommend that the Commission express a strong preference for open standards in its forthcoming order, including encouraging the Company to utilize EV equipment compliant with widely accepted open standards, such as OCPP, whenever feasible.

5. The Commission Should Require Consumers To Adjust The DC Fast Charging Rebate Criteria Such That The Minimum Charging Rate For Fleet Charging Be Set At 50 kW And That The Rebate Be Proportional To The Charging Rate At About $300 Per kW.

As originally filed in the case, the Company proposed to provide rebates for DC Fast Charging ("DCFC") based on a minimum charging rate of 125 kW and a rebate of $35,000 per 125 kW charging rate. 6 TR 2308. Michigan EIBC/IEI witness Jester testified that he has long been "a proponent" of high DCFC charging capacity in public charging infrastructure, noting the

[32] EVConnect, *supra*, https://www.evconnect.com/wp-content/uploads/2018/10/EV-Connect-and-OCPP-2018.pdf

inconvenience that charging time adds to travel time for road trips. 8 TR 4480. However, Mr. Jester stated that "for fleets, operational considerations may be addressed quite satisfactorily with lower charging rates that are still in the DC Fast Charging realm." *Id.* He therefore recommended that the minimum charging rate for fleet charging be set at 50 kW and that the rebate be proportional to the charging rate at about $300 per kW. Mr. Jester cautioned that this recommendation should not be read "as a strict rule for rebates," and should be considered together with his testimony that the Commission should provide some discretion to Consumers to adjust rebates as needed to achieve the pilot's learning objectives. *Id.*

On rebuttal, Company witness Nielsen agrees with Mr. Jester that DCFC rebates can be scaled to better meet the individualized requirements of different fleet vehicle applications and grid impacts. 6 TR 2334. At the present time, the Company is now considering a structure wherein a private DCFC rebate would start at $14,000 for 50 kW DCFC and scale up at $280/kW up to a $35,000 maximum for 125 kW or greater DCFC. A publicly accessible DCFC rebate would start at $28,000 for 50 kW DCFC and scale up at $560/kW up to a $70,000 maximum for 125 kW DCFC. *Id*. Ms. Nielsen states that "Such a change would also reduce grid impacts by allowing smaller DCFC kW applications into PowerMIFleet instead of the 125 kW minimum originally proposed." *Id*.

Michigan EIBC/IEI fully supports both witness Jester's and witness Nielsen's proposed, lower charging rate, starting at 50 kW DCFC, as well as the initial rebates as articulated by witness Nielson on rebuttal.

6. The Commission Should Encourage Consumers To Focus On "Managing Charging" Rather Than "Demand Response" In Its Concierge Service And Other Work With Fleet Charging.

Responding to the Company's proposal to include work on demand response in the Program, Michigan EIBC/IEI witness Jester cautioned that "peak demand is not the only cost driver, nor is response at times of 'called' peaks the only time that responsive demand will be useful." 8 TR 4480. He therefore recommended that, as part of the proposed concierge service, the Company reframe this part of the Program as "managed charging," with a view to minimizing the total cost of charging consistent with the fleet's operational needs. *Id*.

While the Company disagrees with witness Jester's reframing of the program as "managed charging," it "does agree that managed charging for non-workplace applications is a goal of the pilot." 6 TR 2335. The Company states that it proposes to test EVs as a demand response asset in a workplace setting in order to understand the potential and cost of these assets for demand response. *Id.* However, the Company states that "creating cost-effective managed charging scenarios for customers engaged in the pilot aids both the customer and the grid, as well as society via emission reductions from increased EV adoption." *Id*. In that regard, the Company agrees that managed charging is an objective of the proposed concierge service program component. Thus, witness Nielsen stated on rebuttal that, "The Company's expectation is that the concierge consultants will help create cost-effective managed charging scenarios for programmatic participants." 6 TR 2336.

While Michigan EIBC/IEI supports witness Jester's recommendation to reframe the demand response part of the program as "managed charging," it is noteworthy that the Company agrees that managed charging for customers engaged in the Program is a goal, that customers benefit from the creation of cost-effective managed charging scenarios, and that managed charging will be an objective of the proposed concierge service program component.

7. The Commission Should Require That An Analysis Of Electrification Of Consumers' Fleet Be Included In its Next Rate Case.

Michigan EIBC/IEI witness Jester expressed surprise and dismay that the Company, which is the 220th largest private fleet owner in the country, did not initially include its own fleet in the PowerMIFleet Program. He stated that "Consumers Energy should not include its own fleet in the infrastructure spending or rebates to be provided by PowerMIFleet, but should take advantage of the learning opportunity and apply its proposed concierge service to its own fleet and develop an electrification plan for that fleet." Mr. Jester recommended that the Commission require that the Company provide an analysis of electrification of Consumers' fleet in its next rate case. 8 TR 4478.

On rebuttal, Consumers agrees with most all of witness Jester's suggestions. Specifically, Company witness Nielsen testified that:

> The Company does not object:
>
> (i) with analyzing the Consumers Energy fleet as part of the concierge experience, as it would be valuable for both the Company's internal fleet electrification goals (announcement coming this fall) and for the experiential learning to help better serve customers in the future; or
>
> (ii) that this addition would be a good use of any expanded education budget, as some parties have proposed, or transfer of cost savings from other programmatic areas into the education budget.
>
> The Company, however does not support the timing suggestion for inclusion in the next rate case, as that process may need more time given the size and variety of the Company's fleet. Further, the Company wants to devote most of its time and energy, especially during the initial launch, in further developing and implementing the PowerMIFleet Program so that it is done well and experiences the positive outcomes that the PowerMIDrive Program has experienced.

6 TR 2333. Michigan EIBC/IEI are pleased to see that the Company supports Mr. Jester's recommendations. However, we continue to support the recommendation for an update of the

Company fleet program in Consumers' next electric rate case. Consumers should be required to commit to this reasonable time period for an update of whatever the Company's learnings are as of that date, instead of the Company's preference to decide when it will provide an update.

8. The Commission Should Require Further Review, Documentation And Annual Reporting Of The Program.

Michigan EIBC/IEI witness Jester made several recommendations regarding the need for at least an annual report of the PowerMIFleet Program, stakeholder and Commission Staff review of the project plans prior to initiation, the ability to have meetings with interested stakeholders, including Commission Staff, in order to obtain feedback about adjustments to the Program, and more detailed (potentially anonymized) case reports from the concierge service as part of the Program's evaluation. 8 TR 4475.

Regarding the concierge service, Mr. Jester noted that "as part of the Education and Outreach portion of the project [it] is likely the most valuable learning opportunity in the entire proposal, as it affords Consumers the opportunity to engage in depth with fleet owners, understand their concerns and issues, and discover the factors that ultimately influence their decisions to begin electrification at this time or not." *Id*. However, Mr. Jester noted that Consumers indicates that it will be "making such observations," but stops short of committing to report on them to the Commission and stakeholders. *Id.*

Other parties, including Staff, also call for more reporting, specified reporting areas for the Program, and periodic meetings amongst stakeholder to discuss Program learnings. In part, the Ecology Center and ELPC witness Samantha Houston recommends "robust public reporting of the data and lessons learned from the Program," including specified data on the types and distribution of fleets participating in the infrastructure program, as well as other aspects of the Program. 8 TR 4141-4142. MEC witness Max Baumhefner recommends that the Company make a commitment to: 1) engage in robust evaluation of the success of the component programs (Rebates, Demand Response, Bi-directional Power Flow, and Education & Outreach) throughout the length of the pilot program; 2) engage in that evaluation for each program at least every year, if not twice a year or, in some cases, quarterly; 3) share the lessons learned with stakeholders and the public, and 4) conduct a regular stakeholder meeting for PowerMIFleet quarterly and separate from the existing EV stakeholder outreach. 8 TR 3956. Witness Baumhefner states that "The proposed programs are ambitious, and the data gathered and conclusions drawn will be useful for defining best practices to come, and the Company should be providing this data and their analysis for the benefit of their customers, and the citizens of Michigan. quarterly stakeholder meetings, separate from the existing EV stakeholder outreach." *Id*. And Staff witnesses Withenshaw and Mullkoff each recommend continued and consistent work with Staff and stakeholders, as well as additional reporting of the Program. Specifically, Staff witness Withenshaw suggests that the Company work with stakeholders throughout the Program, as it has since the inception of PowerMIDrive, and encouraged quarterly and annual updates to provide opportunities for the Company to share lessons learned. She also requested a formal report after the first 12 months of the implementation of the Program, consistent with the PowerMIDrive report. Witness Sarah A. Mullkoof recommends, in part, quarterly dialog per the pilot timeline, and that if the pilot is expected to continue for more than one year, then Staff recommends an interim impact evaluation be conducted after the first year of the pilot. 8 TR 4833-4834.

For its part, in response to all of these interested parties, Consumers only commits to a "kickoff meeting" with stakeholders before the PowerMIFleet Program begins and an annual stakeholder meeting to gather feedback before filing the annual PowerMIFleet report. The

Company opposes quarterly updates with all parties to this case and any other formal meetings with stakeholders. The Company states its EV team is willing to informally update Staff on a quarterly or semi-annual basis. 6 TR 2331-2332; 2343; 2345; 2349.

Michigan EIBC/IEI submit that these interested parties, including Staff, are unanimous in requesting more information and the opportunity to engage in dialog with the Company other than the Company's initial "kick-off" meeting and via an annual report. While the Company agrees to meet with Staff on a quarterly basis, the refusal to meet with other interested party experts during the operation of this important pilot program should not be accepted. At the very least, as Staff testified, "incorporating stakeholder input" is one of the many "best practices" that Staff has identified for pilot projects through its Mi Power Grid initiative, the Energy Programs and Technology Pilots workgroup. 8 TR 4835. For all of these reasons, Michigan EIBC/IEI respectfully requests that the Commission adopt the recommendations made by witness Jester on the reporting and inclusion of case reports from the concierge service as part of the Program's evaluation.

B. The Commission Should Approve The Recovery And Amortization Of 2019 Costs Of The PowerMIDrive Pilot Project As Proposed By Consumers.

As witness Jester testified, he is thoroughly familiar with Consumers' initial electric vehicle infrastructure proposal, the PowerMIDrive pilot project, as he testified both in the initial Commission case where the pilot was proposed (Case No. U-17990) and ultimately in the case in which it was approved (Case No. U-20134). On behalf of Michigan EIBC, Mr. Jester testified in support, but with recommendations, for the PowerMIDrive pilot project. Overall, Mr. Jester's principal concern with the PowerMIDrive pilot project has been to ensure that this pilot and a similar one operated by DTE, and its related activities of the Michigan Energy Office, are effective in providing an initial DC Fast Charging network in the Lower Peninsula of Michigan.

Thus, Mr. Jester surmises, learnings "are need from these pilot projects regarding both market barriers to and grid integration of electric vehicle charging." 8 TR 4473.

Company witness Sarah R. Nielsen detailed the PowerMIDrive spend for 2019, noting that the projected spend for 2019 is approximately $627,000, and as of month-end October 2019, actual spend totaled $514,862.68. 6 TR 2323. Exhibit A-91 (SRN-2). Witness Nielsen also states that, as required by the Commission, a formal report reflecting actual costs for the pilot program's first year will be submitted to the Commission in the summer of 2020. *Id.*

Witness Jester supports Consumers' requested PowerMIDrive expenditures through 2019, as well as proposed amortization of the pilot. Noting that Consumers has performed this pilot project generally well, Mr. Jester testified that "In general, the DC Fast Charging network is progressing faster than I had anticipated. Residential response to time-of-use rates have been strong, but residential customer participation in time-of-use rates and demand response has advanced more slowly than hoped, for reasons (largely communications system integration) that Consumers has responded to. The multifamily residential market still needs some additional attention in order to understand how to best make infrastructure available to that segment of the public." *Id.*

Michigan EIBC/IEI supports witness Jester's recommendation that the Commission approve the requested PowerMIDrive expenditures and amortization of the pilot program.

VI. CONCLUSIONS AND PRAYER FOR RELIEF

WHEREFORE, for the Michigan Energy Innovation Business Council and the Institute for Energy Innovation hereby respectfully requests that the Commission consider the comments contained in its filed testimony, exhibits and this brief, and adopt its findings and recommendations contained herein.

Respectfully submitted,
Varnum LLP
Attorney for the Michigan Energy Innovation Business Council and Institute for Energy Innovation

August 27, 2020

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief. _______________________________________	))))))	**Case No. U-20697**

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF INGHAM)

Sarah E. Jackinchuk, the undersigned, being first duly sworn, deposes and says that she is a Legal Assistant at Varnum LLP and that on the 27th day of August, 2020 she served copy of the Initial Brief of Michigan Energy Innovation Business Council and Institute for Energy Innovation upon those individuals listed on the Service List via email.

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