STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of Consumers Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023	))))))	Case No. U-21816

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on August 1, 2025.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before August 11, 2025, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before August 18, 2025.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Jonathan F. Thoits

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Jonathan F. Thoits
Administrative Law Judge

August 1, 2025
Lansing, Michigan

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of Consumers Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	))))))	Case No. U-21816

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On November 15, 2024, Consumers Energy ("Consumers" or "Company") filed its application with supporting testimony and exhibits seeking approval of its amended renewable energy plan (REP), and related relief, pursuant to 2008 Public Act 295, as amended by 2016 PA 342 and 2023 PA 235, MCL 460.1001 *et seq.*

Pursuant to due notice, a pre-hearing conference was conducted on January 8, 2025. Consumers and Commission Staff appeared at that proceeding, the Attorney General intervened by right, and intervention was granted to the Michigan Environmental Council (MEC); Cadillac Renewable Energy, Genesee Power Station Limited Partnership, Grayling Generating Station Limited Partnership, T.E.S. Filer City Station Limited Partnership, and National Energy of McBain (collectively the biomass merchant plants or BMPs); Hemlock Semiconductor Operations (HSC); the Michigan Energy

Innovation Business Council and the Institute for Energy Innovation and Advanced Energy United (collectively, MEIU); Association of Businesses Advocating Tariff Equity (ABATE); the Ecology Center, the Environmental Law and Policy Center, Union of Concerned Scientists, and Vote Solar (collectively, the Clean Energy Organizations or CEO); and the Great Lakes Renewable Energy Association (GLREA).[1] On January 16, 2025, the National Resources Defense Council (NRDC) filed a Petition to Intervene Out of Time, which was granted on January 30, 2025. In its petition, the NRDC agreed that it would file joint testimony and briefs with the MEC. On January 21, 2025, a protective order was issued.

Pursuant to a scheduling memo, hearings were held on April 21 and 24, 2025. During the hearings, Consumers presented the testimony of the following employees:

1. Kenneth D. Johnston, Director Regulatory Operations, Electric Supply Regulatory Strategies (Direct and Rebuttal);
2. Marc R. Bleckman, Executive Director of Financial Planning and Analysis (Direct and Rebuttal);
3. Eugene M. Breuring, Principal Sales Forecasting Analyst in Financial Planning & Analysis (Direct);
4. Thomas P. Clark, Executive Director of the Clean Energy Development Department (Direct and Rebuttal);
5. Chibuzo C. Obikwelu, Engineer Technical Analyst in the Electric Supply Regulatory Strategies Section of the Electric Supply Department (Direct and Rebuttal);
6. Zachery S. Cole, Renewables Engineer in the Electric Supply Regulatory Strategies Department (Direct and Rebuttal).

Through these witnesses, Consumers entered exhibits A-1 through A-46.[2]

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[11] 1 Tr 8-9.
[2] Certain testimony and exhibits filed by the parties in this case are deemed confidential and have been filed under seal.

Commission Staff presented the testimony of four employees:

1. Jesse J. Harlow, Manager of the Renewable Energy Section of the Commission's Energy Resources Division (Direct and Rebuttal);
2. Zachary C. Heidemann, Public Utilities Engineer in the Resource Optimization and Certification Section of the Commission's Energy Resources Division (Rebuttal);
3. Kevin S. Krause, Gas Cost Service Specialist in the Rates and Tariff Section of the Commission's Regulated Energy Division (Rebuttal);
4. Nicholas M. Revere, Manager of the Rates and Tariff Section of the Commission's Regulated Energy Division (Rebuttal).

Staff presented Exhibit S-1.

The Attorney General presented the Direct testimony of Michael W. Deupree, Research Consultant with the Acadian Consulting Group and entered Exhibits AG-1.1 through AG-1.12.

ABATE presented the testimony of Jessica A. York, Consultant and Principal with Brubaker & Associates, Inc. (Direct and Rebuttal) and entered Exhibits AB-1 through AB-11.

The BMPs presented the testimony of Richard A. Polich, P.E., Senior Director with GDS Associates, Inc. (Direct and Rebuttal) and entered Exhibits BMP-1 through BMP 11, BMP 11-ii, and BMP-12 through BMP-17.

The CEO presented the testimony of Lee Shaver, Senior Energy Analyst for the Union of Concerned Scientists (Direct and Rebuttal) and entered Exhibits CEO-1 through CEO-5.

GLREA presented the testimony of Robert Rafson, Member of the GLREA Regulatory Affairs Committee and Owner of Chart House Energy, LLC (Direct) and John Richter, Member of the GLREA Board of Directors and Chairman of the Policy Committee (Direct and Rebuttal) and entered Exhibits GLREA-1 through GLREA-3.

MEC-NRDC presented the Direct testimony of Eli K. Gold, Lead Consultant at 4 Lakes Energy and Douglas B. Jester, Managing Partner of 5 Lakes Energy; and entered Exhibits MEC-1 through MEC-18, MEC-19C, MEC-20C, and MEC-21 through MEC-35.

MEIU presented the direct testimony of Matthew McDonnell, Managing Partner of Current Energy Group and entered Exhibits MEIU-1 through MEIU-4.

HSC did not offer any evidence and did not participate in the cross-examination of any witnesses.

The evidentiary record is contained in the testimony and exhibits bound into the record during the April 21 and 24, 2025 hearings. Consumers, Staff, the Attorney General, ABATE, the CEO, BMPs, MEIU, GLREA, and MEC-NRDC filed initial briefs on May 21, 2025.[3] Consumers, the Attorney General, ABATE, the CEO, BMPs, MEIU, GLREA, and MEC-NRDC filed reply briefs on June 10, 2025.

II.

STATUTORY REQUIREMENTS

Part 2 of PA 295 of 2008, the Clean and Renewable Energy and Energy Waste Reduction Act, as amended by Public Act 342 of 2016 and Public Act 235 of 2023 (the Act) requires electric providers to maintain renewable energy plans (REPs) that meet certain renewable energy credit (REC) portfolio standards, or RPSs.

Section 28 of the Act, as amended by Act 235, requires electric providers to achieve an RPS of 15% through 2029, 50% in 2030 through 2034, and 60% in 2035 and each year thereafter.[4] Electric providers are required to meet the RPS with RECs obtained

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[3] The Attorney General filed a public initial brief and a confidential initial brief. All other initial briefs were public.
[4] MCL 460.1028(1).

by: (a) generating electricity from renewable energy systems for sale to retail customers, (b) purchasing or otherwise acquiring renewable energy and capacity, or (c) purchasing or otherwise acquiring RECs without the associated renewable energy or capacity.[5] For Consumers, the RECs acquired pursuant to subsection (c) must be produced from within the Midcontinent Independent System Operator (MISO) territory and not exceed 5% of the Company's RECs used annually to comply with the RPS.[6]

Section 22 of the Act governs the filing and approval of amended REPs. MCL 460.1022(3) states:

> For an electric provider whose rates are regulated by the commission, the commission shall conduct a contested case hearing on the amended renewable energy plan pursuant to the administrative procedures act of 1969, 1969 PA 306, MCL 24.201 to 24.328. After the hearing, the commission shall approve, with any changes consented to by the electric provider, or reject the amended renewable energy plan.

Under MCL 460.1022(5), the Commission shall approve amendments to an amended REP for rate regulated utilities, such as Consumers, if the Commission determines both of the following:

> (a) That the amended renewable energy plan is reasonable and prudent. In making this determination, the commission shall take into consideration projected costs and whether or not projected costs in prior amended renewable energy plans were exceeded.
>
> (b) That the amended renewable energy plan is consistent with the purpose set forth in section 1(2) and meets the renewable energy credit standard. MCL 460.1022(5).

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[5] MCL 460.1028(5).
[6] Id.

III.

ANALYSIS

Several intervenors challenge certain proposals included in the Company's amended REP, while Staff recommends overall approval subject to review of intervenors' testimony, and it requests certain clarifications. The GLREA recommends that the Commission modify or reject the amended REP, while the BMPs recommend rejection unless, "Consumers agrees to revise the proposed amended REP to include biomass generation in the mix of proposed renewable generation additions."[7]

The Attorney General focuses on uncertainty regarding future renewable energy investments, as well as providing recommendations regarding contract approvals, project ownership, the Financial Compensation Mechanism (FCM), and additional forecasting for future REPs.

ABATE raises concerns about the method for collecting the FCM; proposals for amending the transfer price and schedule, and the Company's proposed accelerated build schedule for Voluntary Green Pricing (VGP) programs.

MEC-NRDC addresses Consumers' proposed wind development, issues associated with RECs, certain contracts and contract approvals, and transfer price. The CEO raise concerns about the need to evaluate renewable energy curtailment and the potential impact on the RPS as well as load growth associated with data centers.

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[7] BMP initial brief, 4.

MEIU advocates for the continuation of a 50/50 split between Company-owned and third party-owned wind, solar and battery projects (with power purchase agreements with Company), and makes recommendations regarding competitive bidding procedures.

For the sake of brevity, this PFD will not address the undisputed aspects of the amended REP and recommends that the Commission approve the aspects of the amended REP that have been reviewed but not disputed by Staff or other intervenors. This PFD will address the distinct aspects of the Company's amended REP that are disputed by the parties.

A. Renewable Energy Credit Portfolio Standard

1. Distributed Generation RECs

Mr. Johnston presented the company's projection for distributed generation (DG) outflow and the Company's current DG program, which was used to determine REC compliance.[8]

GLREA witness Rafson testified that the amended REP includes an increasing number of REC purchases. He recommended that the Commission require Consumers to purchase some of these RECS from DG and PURPA projects before purchasing out-of-state RECs, as long as the RECs cost the same or less than the out-of-state RECs.[9] GLREA witness Richter opined that DG RECs could be used to meet non-contracted VGP customer demand.[10]

In rebuttal, Mr. Johnston dismissed Mr. Rafson's recommendation, testifying that the Company already has contracts in place to purchase certain PURPA RECs and Act

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[8] 2 Tr 51; Ex. A-3.
[9] 4 Tr 621.
[10] 2 Tr 588-590.

235 renders DG RECs value-less for RPS compliance. Additionally, he testified that by Commission order, the purchase of DG RECs is to be considered in VGP pricing proceedings and so should not be considered here.[11] The Company adds that limiting the Company's ability to procure RECs from out of state providers could lead to dormant commerce clause concerns.[12]

Staff witness Heidemann testified that Staff investigated this issue in Case No. U-21375 and developed a simplified model using the RPS requirements, as well as the obligation to serve load, to isolate what effect using DG RECs for either VGP or RPS compliance would have on the total number of renewables required to meet the RPS requirement.[13] Staff concluded that, all else being equal, the use of DG RECs either for VGP or RPS compliance reduces the total number of renewables on the system required to meet the RPS and VGP requirement.[14] He stated that "if the DG RECs from generation that are consumed onsite are sold to another entity, even though the energy produced and consumed onsite is offsetting the load a utility would have to serve, it would no longer be covered by renewable generation as the renewable attribute has been sold" and therefore it is arguable that selling the REC would disqualify customers from the DG program under Act 235.[15] He opined that even if a utility had the data to add the load back in, it couldn't be considered because Act 235 has very explicitly directed how the RPS is to be calculated.[16] Mr. Heidemann stated that if the Commission approves the use of DG

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[11] 2 Tr 122; August 22, 2024 order in Case No. U-21374.
[12] Consumers initial brief, p. 8.
[13] 4 Tr 854-855.
[14] 4 Tr 855.
[15] 4 Tr 855-856.
[16] Id.

RECs, Staff recommends that it be only outflow RECs and that it be done at the Company's discretion, as it is in the best position to manage the amount and timing of DG REC purchases.[17]

Staff witness Revere also provided testimony on GLREA's recommendation, stating that MCL 460.1179 provides that DG customers shall own any RECs granted for electricity generated on the customer's site under the DG program and that MCL 460.1005 limits the size of an eligible electric generator under the DG program to 110% of the customer's electricity consumption for the previous 12 months.[18] He opined that generation by a DG customer has two potential endpoints; use by the DG customer behind the meter or outflow, and the law governing the RPS excludes the outflow from the usage the Company is required to cover with clean or renewable energy."[19] He emphasized that a REC represents the renewable attribute of the generation and that once a REC is produced, the renewable aspects of any generation have been separated from that generation, and such generation is no longer renewable if the REC is sold rather than retired to cover the usage associated with that generation.[20]

GLREA counters that prior Commission orders, such as in Case No. U-21172 which ordered that RECs purchased from DG customers can be used for non-contracted VGP customers and Case No. U-21374, which directed the Company to conduct an outreach session on buying RECs from DG customers, suggest that DG RECs can be

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[17] 4 Tr 856-857.
[18] 4 Tr 879.
[19] Id.
[20] Id.

used under the Act and that Staff's concerns about double counting should be dismissed.[21]

GLREA states that while it agrees with Staff that the use of DG RECs should be limited to customer outflow (as it was never their intention to suggest the sale of RECs from customer self-consumption), they see no legal reason why RECs associated with self-consumption could not be used.[22]

GLREA also agrees that a REC is the renewable attribute of energy generated from a renewable source, but posits that when the Company buys the outflow it is not buying the RECs and therefore the outflow is not renewable.[23] GLREA disagrees with the premise that the subtraction of DG outflow from the Company's load, and buying the REC, would constitute a double-count and asserts that the subtraction of DG outflow can reasonably be considered an incentive for regulated electric utilities to support the expansion of their DG programs.[24] GLREA requests the Commission to declare that DG customers can sell the RECs from their outflow, that the Company may use any such RECs that they may purchase, either in their non-contracted VGP offering, in their contracted RECs offering, or for RPS compliance.[25]

In its brief, Staff opines that, "DG should be treated no differently than any other generation resource" and that "[n]o other renewable resource creates RECs that are salable for generation used onsite, whereby the used generation is still considered

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[21] GLREA initial brief, p. 19.
[22] Id at pp. 19-20.
[23] Id at p. 20.
[24] Id at pp.20-21.
[25] Id at p. 21.

renewable after the RECs are sold."[26] Staff posits that based on the mathematics, which is the only relevant factor, allowing the purchase of DG RECs is double counting.[27]

GLREA counters that Act 235 does not prevent the sale of DG RECs and that not allowing DG customers to sell their RECs constitutes a taking of private property in violation of the Fifth and Fourteenth Amendment of the United States Constitution, and Art 1 , Section 17 and Art 10, Section 2 of the Michigan Constitution.[28] GLREA offers that DG RECs can be used to replace any solar projects removed from the Company's REP.[29] GLREA calls Staff's double-counting argument, "indirect", "convoluted," and a "'Rube Goldberg argument.'"[30] GLREA asserts that this case is the appropriate proceeding to address the issue (not the Company's VGP filing) and requests that the Commission declare in this case that DG outflow RECs may be purchased and used for RPS compliance and that the Company include in its VGP filing this fall, standard contract language for the purchase of DG outflow RECs.[31]

This PFD finds that GLREA's position regarding the sale of DG RECs has some merit. However, this PFD agrees with the Company that issues related to the structure or operation of the VGP program, like the treatment of RECs from DG customers, should be addressed in the Company's VGP filing. This PFD notes that in DTE's amended REP Case U-21662, Staff and DTE also suggested that the issue be resolved in the VGP filing

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[26] Staff initial brief, p. 19.
[27] Id at p. 20.
[28] GLREA reply brief, pp.9-18.
[29] Id at p. 17.
[30] Id at p. 18.
[31] Id at p. 20.

and the ALJ agreed.[32] Based on the foregoing, this PFD declines to adopt GLREA's recommendations in this case and recommends that the parties revisit the issue in Consumers' VGP proceeding this fall. Other issues concerning REC purchases are addressed below.

2. Landfill Gas RECs

MEC-NRDC witness Jester testified that Consumes does not have a procedure in place to confirm that its Landfill Gas RECS are from facilities determined by the department of Environment, Great Lakes, and Energy (EGLE) to employ best practices for methane gas collection and control and emissions monitoring, as required by Act 235.[33] He recommended that the Commission require that Landfill Gas RECs recorded in MiRECs, and available for RPS compliance are only recorded when the landfill source has certification from EGLE that it follows best practices.[34]

Mr. Obikwelu testified that Consumers agrees with Mr. Jester that any new landfill gas contracts should include certification of best practices. But he cautioned that invalidating current landfill gas contracts would jeopardize the Company's ability to comply with the RPS as existing landfill gas contracts represent 3% of its RPS target.[35] Consumers recommends that it be provided with the opportunity to collaborate with landfill gas operators and to consider the options available under current contracts before the Commission determines that these RECs cannot be used to meet the RPS.[36]

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[32] See, Case No. U-21662, PFD issued February 25, 2025, pp. 46-52. See also, April 25, 2024 order in Case No. U-21172, pp. 26-28.
[33] 2 Tr 400.
[34] 2 Tr 401, 413.
[35] 2 Tr 251-252.
[36] Consumers initial brief, 9-10.

MEC-NRDC posits that Consumers is "somewhat" overstating its concerns, noting that the Company's reliance on Landfill Gas RECs drops from 3% to 1% and then to a "negligible amount" after 2025.[37] Further MEC asserts that four of seven landfill gas contracts have "change in law" provisions that could facilitate the Company's ability to comply with Act 235's requirements.[38] MEC argues the Commission should instruct Consumers, "that power purchased from facilities that do not meet the new standards may not be eligible for REC accrual, and that costs for such purchases may be considered imprudent and disallowed in future REP reconciliation cases."[39]

Consumers contends that there has been no Commission or other guidance as to the process for making the best practices determination and the Company should be permitted the opportunity to consider options available under current contracts with landfill facilities before costs are disallowed in a reconciliation proceeding.[40]

In reply, MEC-NRDC states that Act 235 does not provide for a grace period and that the Company would have the time available between now and its REP reconciliation cases to "deal with its landfill contract counterparties."[41]

This PFD agrees with MEC-NRDC that Act 235 requires that Landfill Gas RECs be sourced from facilities that employ best practices for methane gas collection and control and emissions monitoring, as determined by EGLE. This PFD finds the Company's request for a grace period unavailing and further notes that the Company should have been on notice since the passage of Act 235 in 2023 that such requirements

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[37] MEC-NRDC initial brief,41.
[38] *Id.*
[39] MEC-NRDC initial brief, 42.
[40] Consumers reply brief, 4.
[41] MEC-NRDC reply brief, 1-2.

were going to be necessary in order for Landfill Gas RECs to be used to meet the RPS. Therefore, this PFD finds that the Commission should instruct Consumers that power purchased from landfill gas facilities that do not have best practices certification by EGLE may not be eligible for REC accrual, and that costs for such purchases may be considered imprudent and disallowed in future REP reconciliation cases

3. Incentive RECs

a. On-peak and Off-peak Incentive RECs

MCL 460.1039(2)(b) grants incentive RECs for non-wind renewable energy resources at "peak demand time as determined by the commission." MEC-NRDC witness Gold testified that the Company calculates the value of these incentive RECs based on a MISO definition of "on-peak hours" of "0600 through 2200 EST, excepting weekends and some holidays" that is from a 16-year-old temporary Commission order.[42] He maintained that "a lot about the grid has changed" and the definition is "outdated."[43] He opined that "because wind and solar are variable, high demand is no longer the principal determinant of the need for incremental capacity" and that "MISO is increasingly focused on resource contributions during "tight hours" when the net availability of resources does not exceed demand by a large margin."[44] Mr. Gold recommended that the Commission base its definition of "peak demand time" on the times when non-wind renewable resources provide capacity value as accredited by MISO. These are currently the hours ending 15,

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[42] 2 Tr 432; Ex. MEC-9; December 4, 2008 temporary order in Case No. U-15800.
[43] 2 Tr 432.
[44] 2 Tr 432-433; Ex. MEC-11.

16, and 17 for Summer, Fall, and Spring, and the hours ending 8, 9, 19, and 20 for Winter.[45]

Mr. Johnston responded that the Company has no choice but to follow the Commission's direction provided in its December 4, 2008 temporary order in Case No. U-15800 (Temporary Order) and has done so in each of its renewable cost reconciliations since 2009.[46]

Mr. Obikwelu testified that any change to the definition of "peak demand time" that the Commission established in the Temporary Order would also have an impact on other electric providers in Michigan and their REC compliance obligations. Therefore, if the Commission determines such a change is warranted, it should be addressed as part of an industry workgroup.[47]

Mr. Harlow opined that the definition was not necessarily outdated and that it would be premature to update it.[48] He testified that Staff agreed with the Company that changing the definition would impact all electric providers and consequently, he recommended that this discussion take place in a standalone workgroup or in a transfer price workgroup.[49]

In briefing, MEC-NRDC opines that "neither Consumers nor Staff presented a compelling reason to keep using the outdated definition of "peak demand time." MEC-NRDC's arguments for a new definition focus on the inconsistency between the definition in the Temporary Order and MISO's current tariff, and it notes that subsection 39(2)(b)

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[45] 2 Tr 433-434.
[46] 2 Tr 106.
[47] 2 Tr 250.
[48] 4 Tr 808.
[49] Id.

uses “peak demand time,” not “on-peak.”[50] MEC-NRDC also relies to a great extent on the PFD and settlement agreement in Case No. U-21662 (DTE Electric’s amended REP proceeding) to support its recommendation to redefine peak demand time to calculate incentive RECs under subsection 39(2)(b).[51] MEC-NRDC argues that if the Commission agrees that the Temporary Order definition needs reconsideration, the Commission should not approve Consumers’ calculation of its incentive RECs[52]

This PFD agrees with MEC-NRDC that “peak demand time” as defined in the Temporary Order for incentive RECs may no longer be suitable, but this PFD declines to adopt MEC-NRDC’s recommendation to disapprove the Company’s calculation of incentive RECs under MCL 460.1039(2)(b). This PFD determines that it would be unreasonable to implement a new definition in this case when this is an industry-wide issue. Accordingly this PFD recommends that the Commission create a workgroup to develop an updated definition of peak demand time to be used in calculating incentive RECs under subsection 39(2)(b).

b. Off-peak Generation for Storage Incentive RECs

MCL 460.1039(2)(c) provides incentive RECs for renewable energy generated during off-peak hours, stored using an energy storage system or pumped storage facility, such as Ludington Pumped Storage (Ludington) and then used during peak hours. The value of the RECs are based on the amount of energy used to charge the storage system or pumped facility.[53]

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[50] MEC-NRDC initial brief, 24-25.
[51] Id at 27-28.
[52] Id at 29.
[53] MCL 460.1039(2)(c).

Mr. Gold objected to the Company's use of MISO's "broad" definition for off-peak hours, which includes all hours 11 PM to 7 AM and all hours on weekends, when calculating incentive RECs under subsection 39(2)(c).[54] He testified that it is also incorrect for the Company to base its calculation on the premise that "if renewable energy is generated during off-peak periods while energy storage is occurring, it shall be presumed that the renewable energy is stored," which is also from the Temporary Order that the Company used to calculate the credits under subsection 39(2)(b).[55] Mr. Gold explained that this is inconsistent with how the power system currently operates and it is unreasonable to assume that all renewable generation is preferentially used for pumping (or charging) for the purpose of calculating incentive RECs.[56] He explained that "[w]hen Ludington Pumped Storage Plant pumps water to charge the system, that power is drawn from the MISO grid and adds to the load that MISO serves. That incremental load will be served by the next resource in the economic dispatch sequence and, as such, is not served by renewables unless renewable generation is so high relative to load at that time that renewable generation is curtailed."[57]

He recommended that the Commission should deem that electricity generated from a renewable energy system during off-peak hours is stored using an energy storage system or hydroelectric pumped storage facility only when renewable resources are marginal in merit-order dispatch and would have been curtailed in the absence of charging a storage resource.[58] Further Mr. Gold recommended that the Commission

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[54] 2 Tr 434.
[55] 2 Tr 434-435.
[56] 2 Tr 435.
[57] Id.
[58] 2 Tr 436.

authorize incentive RECs pursuant to MCL 460.1039(2)(c) only to the extent that stored renewable energy is discharged during peak periods, as determined by the Commission.[59] He stated that if the Commission adopts his recommendations that the amount of the Company's earned incentive RECs would be "materially reduced" and would need to be recalculated.[60]

Mr. Johston disagreed with Mr. Gold's assessment of the source of power used to charge Ludington. He testified that "[r]egardless of whether the marginal resource is renewables, power flows in the path of least resistance and unless the marginal resource is located adjacent to the Ludington Pumped Storage Facility, it is unlikely that it is serving the electric load instead of renewables."[61] He explained that when the Company's Lake Winds Energy Park (Lake Winds), located in Ludington, is generating and the reservoir is being filled, Lake Winds is likely the source of that electric power.[62] He maintained that the actual electric energy that serves the pumping load at Ludington is not tracked and, as such, no determination can be made that it is not being charged by renewable energy sources.[63] Further, he opined, it is not fair to assume that the pumping load at Ludington is only served with marginal market resources since the Company can bid it in its day ahead submittal and it gets the same locational marginal price (LMP) that all other load resources receive.[64]

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[59] 2 Tr 436-437.
[60] 2 Tr 437.
[61] 2 Tr 106.
[62] Id.
[63] 2 Tr 107.
[64] Id.

MEC-NRDC argues that if, as the Company maintains, it is impossible to know how many megawatt hours of renewable energy are being used to charge Ludington during a given time interval, then, there is no substantial evidence to support the Company's current claim for incentive RECs.[65] MEC-NRDC maintains that the Commission should either adopt Mr. Gold's recommendation and only allow Consumers to claim incentive RECs for Ludington when renewable energy is the marginal resource during off-peak hours when Ludington is pumping, or it should direct a process for modifying the method with interested parties' input.[66] MEC-NRDC refers to the PFD and subsequent settlement agreement in DTE Electric's amended REP case, U-21662, which generally recommended the calculation of incentive RECs under subsection 39(2)(c) be considered in a workgroup.[67]

This PFD acknowledges that the current method for calculating incentive RECs under subsection 39(2)(c) is imperfect, as noted by MEC-NRDC (and by the Company), and it is not unreasonable to adopt a new method that more accurately reflects the amount of renewable energy used to serve the pumping load at Ludington. However, this PFD recognizes that Ludington is co-owned by Consumers and DTE Electric and, as such, any resolution of the issue of incentive RECs association with that facility should be applicable to both utilities. Accordingly, and consistent with this PFD's determination on subsection 39(2)(b) and with the settlement agreement in Case No. U-21662, this PFD recommends that this issue be addressed in an industry-wide workgroup.

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[65] MEC-NRDC initial brief, pp.32-33.
[66] Id at p. 33.
[67] Id at p. 34.

4. REC Market Purchases (REC Only Contracts)

Mr. Obikwelu testified that Consumers plans to meet the RPS targets, in part, through RECs purchased from the market (market RECs) as permitted under Section 28(5)(c) of Act 235.[68]

Mr. Gold testified that the Company's purchase of market RECs is expensive and unnecessary. He explained that Consumers plans to purchase 7,013,979 RECs from 2026 through 2035, at a projected cost of $2 per REC, which is over five times higher than the average Company-owned or PPA-purchased RECs at $0.35.[69] He further indicated that the Company's projected cost of $2 per REC is likely too low as a tightening in the REC market is anticipated.[70] He also noted that in its amended REP, DTE Electric assumed a cost of $3 per REC until 2030 and $5 per REC after 2030.[71] Additionally, Mr. Gold explained that, by Consumers' own accounting, the Company does not need to purchase market RECs to comply with the RPS.[72] He opined that including these RECs in Consumers' REP reduces its incentive to ensure it can own or contract for "genuinely additive renewable energy."[73] He recommended that Consumers be prohibited from purchasing or planning to purchase market RECs and that these RECs only be allowed if they are purchased in response to a short-term risk of non-compliance with the RPS.[74] He testified that while he does not support the use of market RECs "at all," if the

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[68] 2 Tr 243; Ex. A-36.
[69] 2 Tr 419; Ex. A-38.
[70] 2 Tr 419.
[71] Id.
[72] 2 Tr 421.
[73] Id.
[74] Id.

Commission does approve their use, that it condition its approval on the RECs being Green-e® certified.[75]

Consumers argues that its plan to purchase market RECs is permitted under MCL 460.1028(5)(c) and that Mr. Gold's cost comparison of market RECs and Company owned RECs is not valid.[76] Mr. Obikwelu explained that the Company plans to use market RECS as a cost-effective way to ensure RPS compliance in light of the risks inherent in the amended REP, such as siting, tariffs, interconnection, sales and price uncertainty, and tax credits.[77] He opined that waiting to purchase these RECs until there is a potential shortfall reduces the Company's flexibility to build a larger REC bank, which helps to ensure that the Company is able to comply with the RPS.[78] He added that it is unnecessary to require Green-e® certification of market RECs since MIRECS is a sophisticated tracking system that uses several measures to protect the integrity of the RECs as well as prevent any double counting.[79]

MEC-NRDC states that while Mr. Gold's calculated $0.35 average for non-market-purchased RECs may be inaccurate, market-purchased RECs "are still far too expensive for the value they provide to rate-payers", which MEC-NRDC maintains, is "essentially zero."[80] MEC-NRDC asserts that there are better ways to mitigate risks, such as procuring more wind generation and using PPAs from in-state and out-of-state resources.[81] MEC-NRDC refers to the PFD in Case No. U-21662 as well as the settlement agreement and

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[75] 2 Tr 420.
[76] Consumers initial brief, 12.
[77] 2 Tr 250; Consumers initial brief, 12.
[78] Id.
[79] Id.
[80] MEC-NRDC initial brief, p. 17-18.
[81] Id at p. 18.

argues that the use of market RECs "would not be reasonable and prudent unless no other avenues for compliance – i.e., generation or purchase of renewable energy and capacity – were available."[82]

This PFD notes that subsection 28(5)(c) of the Act explicitly allows electric providers to meet up to 5% of the RPS requirements through 2035 by purchasing market RECs. If the Legislature intended to place more or different restrictions on the acquisition of these RECs, as MEC-NRDC recommends, it would have done so in the Act. This PFD also notes that as suggested by MEC-NRDC, the Company has the burden of demonstrating in applicable REP reconciliation proceedings that REC-only contracts are reasonable and prudent and necessary to comply with the RPS.[83] Further, MCL 460.1028(6) requires that the Commission review any REC-only contracts. Therefore, there are appropriate mechanisms to ensure that the use of market RECs is warranted and is reasonable and prudent. Accordingly, this PFD declines to adopt MEC-NRDC's recommendations on market RECs.

B. Resource Additions

1. Purchased and Company-Owned Solar Energy Resources

GLREA witness Richter raised concerns about the Company's reliance on transmission-connected solar facilities in the amended REP. He testified that distribution connected facilities can avoid scheduling risks because they do not have to go through the MISO interconnection process and can avoid or reduce transmission and energy line losses.[84] He recommended that the Commission order that in its next solicitation, the

[82] Id at pp. 19-20.
[83] Id at pp. 19-20.
[84] 4 Tr 579.

Company include an option for a distribution-connected pilot, with a list of connection points where the addition of generation would support the distribution grid, and the capacity of generation each interconnection point could support; or in the alternative, direct the Company to create a standard contract for smaller, distribution connected solar facilities (under 5 MW), with pricing based on recent Company solicitations.[85]

Similarly, MEC-NRDC witness Jester testified that there are benefits to distribution connected solar, such as more favorable siting when compared to larger projects and the avoidance of the MISO interconnection queue.[86] However, according to him for a number of reasons, the Company's competitive procurement process does not favor these smaller projects.[87]

Mr. Jester noted that MCL 460.1028(6) provides in part that: "[t]he commission shall not approve a contract based on an unsolicited proposal unless the commission determines that the unsolicited proposal provides opportunities that may not otherwise be available or commercially practical through a competitive bid process."[88] He recommended that this statutory provision be used to require Consumers to make available standing offer contracts for projects under 5 MW that are located in settled areas where land parcel sizes are usually small, on brownfields, and for agrivoltaics projects.[89] He further suggested that the prices for the standing offer contracts should be based on the prices of projects selected in that year's RFP but adjusted for differences in line losses

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[85] 4 Tr 581.
[86] 2 Tr 409-411.
[87] Id.
[88] 2 Tr 412.
[89] Id.

between the project location and the physical load served by the project versus line losses between large projects and the physical load they serve.[90]

Mr. McDonnell similarly recommended a carveout for mid-size solar projects because such projects occupy an often-overlooked sweet spot in the industry.[91] He noted mid-sized solar projects are "large enough to leverage the economies of scale enjoyed by utility-scale systems, so they can be developed at costs that are highly competitive," but, unlike utility-scale systems, can be flexibly located, can provide distributed benefits such as avoided transmission line losses, deferral of distribution infrastructure, and increased system resilience, can interconnect to medium-voltage distribution systems resulting in a more streamlined and less expensive interconnection process, and can take advantage of the expanded federal Investment Tax Credit (ITC) for interconnection costs for solar projects less than 5 MW.[92] In addition, he indicated that project size diversity may lessen RPS compliance risk. Therefore, he proposed an initial approach that includes "a target for mid-size projects to comprise 10% of total incremental solar resource additions over the relevant three-year period."[93]

Mr. Cole responded that while the Company's modeling assumes a levelized cost of energy (LCOE) based on transmission-connected solar facilities, Consumers intends to continue to allow distribution connected facilities in its annual RFPs and will continue to consider them on the same basis as transmission-connected projects and to the extent that distribution-connected facilities can provide timely and economic renewable energy

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[90] Id.
[91] 4 Tr 658.
[92] 4 Tr 658-659.
[93] 4 Tr 659.

resources, they will be considered for selection."[94] He noted that the smallest sized project that historically could participate in the Company's RFP has been 0.15 MW for PURPA qualifying facilities (QFs) and a minimum offer capacity of 1 MW for non-PURPA facilities.[95] He added that the Company has signed multiple PURPA contracts for resources less than 5 MW in each of the last three years.[96]

Mr. Cole also disagreed with the recommendation for a procurement carveout of up to 10% for mid-size solar resources. He contended that, to the extent Mr. McDonnell's reasoning is correct that these projects provide economic benefits, there is no need to create a carveout because these resources are already economically competitive.[97] Regarding Mr. McDonnell's assertion that mid-size projects can be flexibly located and provide distribution system benefits, he contended that this claim would be better assessed in an IRP filing where system-wide detailed modeling is performed.[98] He also noted "the Company allows distribution connected projects to bid into RFPs and utilizes distribution specific assumptions for modeling the economics of distribution projects in RFPs."[99] Regarding the claim this carveout would integrate project size diversity and lower risk of noncompliance with the RPS, Mr. Cole pointed out the cost of this risk avoidance was not considered and that the Company already mitigates risk by including REC purchases as a buffer for potential project delays.[100]

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[94] 2 Tr 359.
[95] Id.
[96] 2 Tr 362.
[97] 2 Tr 363-364.
[98] 2 Tr 364.
[99] Id.
[100] 2 Tr 365.

GLREA counters that Consumers' response that it allows developers to bid smaller systems into a solicitation that also allows much larger transmission-connected systems is not sufficient, because it fails to recognize the cost savings of avoiding transmission system interconnection.[101] According to GLREA, in addition to saving hundreds of thousands of dollars in MISO interconnection fees, distribution connected facilities can provide benefits that are difficult to assign a dollar value to, such as having the control and schedule of the interconnect process directly in the hands of the Company.[102] GLREA asserts that a separate solicitation is required to level the playing field for distribution-connected facilities.[103] GLREA also recommends that the Company provide information on areas where its distribution system could support a solar energy system, and of what maximum size, which is currently lacking.[104] GLREA recommends that a distribution-connected solar facility solicitation be conducted as a pilot, with the principal objective of demonstrating the feasibility of this approach, and gaining information from the bidders on how to improve the process. [105]

MEC-NRDC points out that most of the Company's referenced PURPA contracts are for energy only, while the RFP pricing is based on an LCOE that includes both energy and capacity and therefore PURPA is not an economically viable avenue for the types of small solar projects described by Mr. Jester.[106]

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[101] GLREA initial brief, pp. 14-15.
[102] Id at p. 15.
[103] Id at p. 16.
[104] Id.
[105] Id at pp. 16-17.
[106] MEC-NRDC initial brief, pp.37-38.

With respect to the proposed carveout for mid-size solar projects, Mr. Harlow testified that Staff is concerned about ratepayer subsidization and uncompetitive costs but he was intrigued by Mr. McDonnell's discussion asserting that smaller scale projects can be cost effective due to the avoidance of transmission interconnection costs.[107]

This PFD agrees with GLREA and MEC-NRDC that distribution-connected solar could provide cost savings and other benefits that Consumers is forgoing by having these smaller solar projects bid into the same solicitation as larger transmission-connected projects. Further, the Company did not provide a compelling reason to decline GLREA's or MEC-NRDC's recommendations to facilitate small solar projects. Therefore, this PFD recommends that the Commission order that in its next solicitation, the Company include an option for a distribution-connected pilot, with a list of connection points in which the addition of solar generation would support the distribution grid, and the capacity of generation each interconnection point could support. In the alternative, the Commission could direct the Company to create a standard contract for smaller, distribution-connected solar facilities (under 5 MW), with pricing based on recent Company solicitations.

2. Company-Owned Wind Energy Resources

Mr. Johnston testified that the Company's amended REP requests approval of up to 2,800 MW of Company-owned wind energy resources to support the increasing levels of REC compliance in 2030 and 2035.[108] Further he stated that all of the Company's resource additions have been modeled to be sourced within MISO Zone 7.[109] He added that "to the extent that the Company is able to identify out-of-state renewable energy

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[107] 4 Tr 815.
[108] 2 Tr 43.
[109] 2 Tr 59. MISO Zone 7 is mostly comprised of the Lower Peninsula of Michigan.

resources that are more financially viable than Michigan renewable energy resources due to factors such as construction cost or capacity factor, the Company will consider executing PPAs for those assets; however, the Company does not intend to own out-of-state renewable energy resources."[110]

MEC-NRDC, MEIU, and the Attorney General criticized certain aspects of the Company's wind resource addition plans, while Staff generally found the plans reasonable.

Mr. Gold asserted that Consumers backloads its major acquisition of new projects into two years: 1,500 MW in 2032 and 800 MW in 2035.[111] He contended that "[i]n the history of wind energy development in Michigan, there has never been a year with more than 600 MW of new wind energy brought on the grid."[112] Therefore, he found Consumers' build plan, "unrealistic."[113] He also noted that because of the increased RPS and the new clean energy standard (CES), there will be increased competition for renewable energy development and the longer the Company "waits to begin deployment of major wind projects, the more likely it is the best wind resources in Michigan will have been developed by other utilities."[114] He indicated that the Commission can reduce this risk by recommending that Consumers spread its wind build out between now and 2035.[115]

Mr. Gold objected to Consumers' plan to own all 2,800 MW of the new wind resources, explaining that the Company's predetermination that it will not use PPAs for

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[110] 2 Tr 59-60.
[111] 2 Tr 422.
[112] Id.
[113] Id.
[114] 2 Tr 422-423.
[115] 2 Tr 423, 430.

its wind additions reduces the options available and deprives ratepayers of the benefits of open market competition for the best possible projects.[116] He asserted that the passage of Act 235, as well as Act 233, have produced a clear demand signal for new renewable energy development and have changed would-be developers' perspective on the viability of new wind generation in Michigan.[117] He explained this was evidenced by the bidding of several wind projects into DTE's most recent RFP.[118]

Mr. Gold also took issue with Consumers' foreclosure of out-of-state wind energy purchases. He testified that wind resources are very unevenly distributed geographically, and the availability of low-cost, easily developable wind resources in MISO Zone 7 is low compared with the rest of MISO's North region and the overall need for wind generation to meet Michigan clean and renewable energy goals. He presented modeling data derived from the National Renewable Energy Laboratory's (NREL) reV model that he testified shows a "vast amount of lower cost developable wind resource outside of MISO Zone 7 and Michigan."[119] He acknowledged that there are cost risks to contracting for out-of-state generation, but he asserted that Consumers can manage the risks by evaluating its RFPs on the difference between LCOE and the expected basis differences of both energy and capacity in the resource location vs Consumers' service territory.[120] He explained that while Consumers will need to account for the nuance of contracting for out-of-state

[116] 2 Tr 423-424.
[117] 2 Tr 424-425.
[118] 2 Tr 425.
[119] 2 Tr 426; Ex. MEC-8
[120] 2 Tr 428-430.

generation, the Commission should order Consumers to actively solicit PPAs for wind generation inside and outside of MISO Zone 7.[121]

MEIU witness McDonnell also expressed concerns about the Company's planned wind resource additions. Echoing Mr. Gold, he testified that the pace of wind deployment in the amened REP should be accelerated to "alleviate the potential challenge of deploying resources of that magnitude on such a compressed timeline, while also likely ensuring that these additions will benefit from available tax credits."[122]

He also testified that the Company's plan to own all the new wind resources is out of step with state market trends and past Commission practice and ignores an opportunity to take advantage of cost-competitive PPAs.[123] By not considering opportunities for third-party ownership, he asserted that the Company exposes ratepayers to more risk and increased costs.[124] He indicated that 100% Company ownership also means the Company bears 100% of the costs and associated risks, such as project development and construction risks, including equipment costs, site-specific challenges, and supply chain disruptions, the costs and associated risks of which will be passed on to ratepayers.[125] By contrast, he described PPAs as generally "structured in a manner that mitigates overall risk exposure for ratepayers."[126]

He cautioned that if the Commission approves the Company's sole ownership approach it would "signal a significant policy shift compared to the ownership structure

[121] 2 Tr 430.
[122] 4 Tr 640.
[123] 4 Tr 650.
[124] 4 Tr 640.
[125] 4 Tr 647-648.
[126] 4 Tr 648.

for prior resource procurements, chilling future third-party interest in the State and directing the wind energy market towards a level of utility ownership it has not experienced to date."[127] He contended that the Company's statements that it would be open to competitive contracts does not sufficiently address his concerns and that "without an explicit ownership split and stated goal for third-party-owned resources" third parties are not likely to develop bids for Consumers' solicitations.[128] Mr. McDonnell recommended that the Commission condition approval of the company's wind resource additions upon the extension of a 50/50 split between Company and third-party ownership of the proposed additions and that the Company should be further directed to follow the same competitive bidding processes that it currently does for its IRP resource additions, including the use of an Independent Administrator (IA).[129]

Attorney General witness Deupree testified that, as part of the Company's 2021 IRP Settlement, "the Company agreed that future competitive solicitations would follow existing agreements restricting Company ownership to only 50 percent of future assets."[130] He opined that parties often request limitations on utility ownership of renewable energy resources because PPAs often result in lower costs for customers, as evidenced by the Commission's 2017 Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards, which found the weighted average cost of PPAs to be lower than the cost of company-owned

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[127] 4 Tr 650-651.
[128] 4 Tr 650-651.
[129] 4 Tr 652-653.
[130] 2 Tr 459; June 23, 2022 order in Case No U-21090, p. 9.

projects.[131] Like MEIU, Mr. Deupree recommended that the Commission "reiterate the Company's existing commitment that only 50 percent of renewable energy resources selected through future competitive solicitations be Company-owned" to limit utility involvement in the development of renewable energy facilities in Michigan and thus benefit ratepayers by ensuring healthy competition.[132]

In rebuttal, Mr. Clark explained that "[a]cceleration of the acquisition of wind generation resources is dependent on cost competitive and viable projects being available that are in relatively late stages of development," and projects that meet those criteria are currently scarce.[133] He acknowledged that the recent statutory changes have encouraged new wind development in Michigan. However, he noted new projects will take several years to develop such that they would likely not begin operations until the early 2030s, which is why the Company reflected a large increase in wind acquisition in those years.[134] He maintained that the Company will continue to pursue price-competitive wind projects, which may result in wind resources being acquired sooner.[135]

Mr. Johnston testified that Consumers modeled all wind resource additions as owned, but it is not wedded to this position.[136] However, he stated that the Company does not agree with implementing a 50/50 split between Company-owned wind and PPAs because it believes that it should source new wind energy resources based on economic

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[131] 2 Tr 460; Commission's February 15, 2017 Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of The Energy Standards, p. 19.
[132] 2 Tr 461.
[133] 2 Tr 233.
[134] Id.
[135] Id.
[136] 2 Tr 85.

value and lowest cost.[137] He added that the Company did not model any PPA-based wind resources because a recent solicitation garnered zero bids.[138] Mr. Johnston also emphasized that in addition to considering the lowest cost renewable energy resource, the Company believes that there can be inherent advantages to Company-owned assets, such as the terminal value (the ability to obtain additional value from owned assets beyond the term of a PPA), the ability to re-power, and economies of scale.[139] Mr. Johnston noted that in Case No. U-21374 the Commission rejected MEIU's proposal to require achievement of a certain ratio for the Company's VGP program, as this may "result in inferior projects being selected just to satisfy a predetermined ratio."[140]

Mr. Cole agreed with Mr. McDonnell's recommendation that all RFPs include an Independent Administrator (IA).[141] As to the Company's existing commitment to a 50/50 ownership split as referenced by MEIU and the Attorney General, Mr. Johnston responded that the Company agreed to restrict its solar resources to a 50/50 ownership split, but not its wind (or VGP) resources.[142]

Staff witness Harlow agreed that "the Company's assumption of 100% Company-owned wind is flawed."[143] However, he testified that while Staff has supported a 50/50 requirement in the past, and it believes that the Commission should continue to encourage Consumers to include the option for PPAs in its solicitations going forward, Staff does not believe that it is prudent to require the Company to maintain a 50/50

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[137] 2 Tr 86.
[138] Id.
[139] 2 Tr 87.
[140] 2 Tr 84-85; August 22, 2024 order in Case No. U-21374, p. 11.
[141] 2 Tr 363.
[142] 2 Tr 82-83.
[143] 4 Tr 809.

portfolio.[144] He explained that in light of the significant cost of meeting Act 235's requirements, Staff's opinion is that the Company should be choosing the most economical and feasible resources that meet its requirements, regardless of whether they are third-party or Company-owned.[145] He explained that projects should be chosen primarily on economic merit, but should also consider other components, such as ability to meet timelines, risk associated with the project, financial stability of contractor, etc., as these all can ultimately result in additional costs for rate payers.[146] Nonetheless, he maintained that Staff believes PPAs will be necessary for Consumers to meet its RPS targets and it is imperative that the Company include third-party PPAs in all future RFPs.[147] He opined that allowing third-parties to bid into and compete in RFPs and the Company's continued adherence to the competitive procurement guidelines, as established in Case No U-20852, should ensure a cost-effective renewable procurement strategy going forward.[148]

In its brief, MEC-NRDC responds to Consumers' contention that Michigan wind development will not begin operation until the early 2030s, countering that there is plentiful existing wind in other states that Consumers should pursue.[149]

The Attorney General elaborates on Consumers' agreement to strive for a 50/50 ownership split of its wind assets. She argues that the 2021 IRP Settlement in Case No. U-21090, wherein the Company agreed to a 50/50 ownership split included all types of

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[144] Id.
[145] 4 Tr 809-810.
[146] 4 Tr 810.
[147] Id.
[148] Id.
[149] MEC-NRDC initial brief, p. 14.

renewable generation, including wind, and the Company has failed to meet its burden of proof to show a commercially reasonable effort to achieve such a split.[150]

MEIU elaborates on Mr. McDonnel's testimony and argues that "Consumers should be required to do more than make lukewarm indications that it intends to consider third-party-owned resources alongside its own on an equal basis."[151] MEIU agrees that the amended REP includes "substantial costs," but argues that these costs do not justify turning away from the ownership splits that have been a consistent feature of Consumers' and DTE Electric Company's procurements for years.[152] Further, MEIU contends that the costs of third-party-owned assets generally bring costs down both directly and indirectly by putting downward pressure on utility self-builds including for utility-owned projects.[153]

As for Staff's proposal that the Company continue to include third-party ownership models in all solicitations going forward, MEIU asserts that it does nothing to protect against potential utility monopolistic behavior and its effects.[154]

This PFD agrees with MEC-NRDC and MEIU that Consumers' plan to wait until 2032 and 2035 to add 2,300 MW of wind resources may be imprudent. The Company's response that new wind facilities in Michigan will likely not be operational until these years ignores the current availability of out-of-state wind resources, as pointed out by MEC-NRDC. This PFD appreciates Consumers' statements that it will continue to pursue price-competitive wind projects, in state or out-of-state, but this is not sufficient to ensure the Company's plan for wind deployment is reasonable and prudent and that it will result in

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[150] AG initial brief, pp. 30-33.
[151] MEIU initial brief, pp.4-13.
[152] MEIU reply brief, p. 2.
[153] Id.
[154] MEIU reply brief, pp. 2-3.

RPS compliance. Therefore, this PFD recommends that the Commission predicate its approval of the amended REP on Consumers agreement to accelerate and more evenly distribute its planned new wind development including by actively soliciting PPAs for wind generation outside MISO Zone 7. Further the Company should evaluate its RFPs on the difference between LCOE and the expected basis differences of both energy and capacity in the resource location vs Consumers' service territory and choose the most economical and valid projects that meet its requirements, as recommended by MEC-NRDC.

As to the ownership of the Company's planned wind assets, this PFD notes that, as originally enacted in 2008, Act 295 mandated a 50% PPA requirement for Consumers (and DTE Electric) However, this requirement was repealed by Act 342 of 2016.[155] This PFD finds that this statutory change means that renewables can be owned, in any proportion, by either the Company or by third-parties and that the primary inquiry is what is most reasonable, prudent, and economical for customers, on a case by case basis, properly informed by an RFP. This PFD acknowledges that the Company's commitment to pursue 50% PPAs in the 2021 IRP included wind but finds that the commitment preceded Act 235 and therefore it may no longer be reasonable considering the increased RPS targets that Consumers must meet.

This PFD further acknowledges the validity of the Intervenors' arguments that the Company's 100% ownership plan may preclude the benefits that healthy competition can bring to enable the most cost-effective projects and, as stated above, agrees with Staff that this 100% Company-ownership goal is unreasonable. However, this PFD finds

[155] MCL 460.1033 was repealed by PA 342 of 2016.

persuasive Staff's arguments that an explicit 50/50 ownership split is likewise imprudent and that allowing third-parties to bid into and compete in RFPs coupled with the Company's continued adherence to the competitive procurement guidelines, as established in Case No U-20852, should ensure cost-effective renewable procurement going forward.

Therefore, this PFD declines to require a specific ownership split of any proportion. Instead, consistent with the analysis above, this PFD recommends that Consumers be required to actively solicit third party PPAs in all its future RFPs, including those from outside Michigan, and to select the most feasible and economical projects for customers regardless of ownership. This PFD adopts MEIU's recommendation, with which the Company agreed, that the Commission direct the Company to follow the same competitive bidding processes that it currently does for its IRP resource additions, including the use of an Independent Administrator.

3. Ex Parte Approval and 140% LCOE Multiplier

Mr. Johnston provided the basis of the company's cost assumptions for wind and solar: the modeling of which resulted in an LCOE of $55.44/MWh for wind and an LCOE of $70.31/MWh for solar with a commercial operation date (COD) of January 1, 2028.[156] Mr. Johnston testified that Consumers is requesting that the Commission allow it to receive ex parte approval for future projects for solar and wind renewable energy resources that have an LCOE of up to 140% of the Company's cost assumptions. This would mean that wind projects with an LCOE of up to $77.62 and solar projects with an

[156] 2 Tr 60.

LCOE of up to $98.44/MWh would receive ex parte approval. He explained that the 140% multiplier will reflect multiple risks associated with project development such as:

> . . . developers not passing along tax credits, developers pricing in the risk of tax credits being repealed, MISO interconnection queue delay risk, the Company's experience in its competitive solicitations that few MW (out of the 500 MW targets) are priced at or below the target LCOE, federal tariffs on solar panels and bids reflecting those risks, increasing/inflating construction labor costs, and increasing/inflating cost of land acquisition.[157]

According to Mr. Johnston, these risks have resulted in fewer solar MWs at a competitive price. He testified that a review of solar bids offered that would achieve the Company's targeted capacity (500 MW per year), reveals that the marginal bid is approximately $97/MWh (or approximately 140%).[158]

Several intervenors objected to the Company's proposed 140% of LCOE threshold for ex parte approvals, while Staff found it reasonable.

Mr. Deupree noted that the proposal could increase the costs associated with the amended REP by $373 million and asserted that Consumers "proposes to shift development risks from developers onto ratepayers," who will not receive any additional benefits from shouldering these risks.[159] In addition, Mr. Deupree testified that the Company's baseline LCOE estimates may already be too high. He pointed out that an analysis performed by the United States Energy Information Administration (EIA) in support of its Annual Energy Outlook (AEO) 2023 estimated an LCOE for MISO Region 5 of $27.41/MWh for new onshore wind generation and $26.87/MWh for solar photovoltaic generation, assuming a 2028 COD and 30-year cost recovery period and using 2022

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[157] 2 Tr 61.
[158] Id.
[159] 2 Tr 447, 457-458; Ex. AG-1.1.

dollars.[160] He testified that "[e]ven when examining EIA estimates assuming the removal of tax credits under the Inflation Reduction act, the LCOE for these technologies is significantly less than that estimated by the Company."[161]

MEC-NRDC witness Jester testified that the Company did not provide the analysis that determined the marginal bid was approximately $97/MWh or any rate impact or other analysis to show that acceptance of its proposal will not increase rates or charges.[162] He also pointed out that the LCOE for solar in the amended REP is already significantly higher than in the Company's last IRP, although he acknowledged the prior LCOE reflected a different COD.[163] Mr. Jester recommended that the Commission deny Consumers' request for ex parte approval of projects priced up to 140% of the LCOE and noted this would not prevent Consumers from seeking approval of projects priced higher than 100% of the LCOE but simply require approval to be sought in a contested case.[164]

Mr. Richter testified that the Company's proposal indicates that the modeled wind and solar LCOEs are not an accurate projection of the Company's anticipated future costs and "the cost of the REP build plan could increase dramatically," especially since the permission for ex parte approval, if granted, presumably continues through 2045.[165] Mr. Righter disputed that developers would not pass along tax credits, noting this is not a concern if the bidding reflects real competition as a developer that failed to factor in tax credits would not have a competitive bid.[166] He indicated that tax credits being repealed,

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[160] 2 Tr 458-459.
[161] 2 Tr 459.
[162] 2 Tr 406-407.
[163] 2 Tr 407.
[164] Id.
[165] 4 Tr 559.
[166] 4 Tr 560.

MISO queue delays, and rising costs have always been risks and that these risks could be addressed through contract terms and conditions.[167] He noted that rising costs are already addressed by the 2% per year price escalator.[168] He testified that there is no evidence that developers are including any of these risks in pricing and the Company's assertions are purely speculative.[169]

Mr. Richter disputed that the Company's experience with recent solicitations justifies the 140% multiplier, noting that Consumers' fourth annual IRP solicitation in 2022 received 38 proposals totaling approximately 1,665 MW and its third annual solicitation in 2021 received 28 proposals totaling approximately 1,500 MW.[170] Like Mr. Jester, he noted that the Company did not provide any data to support its claim that the marginal bid was $97/MWh.[171] While he acknowledged that rejection of the 140% multiplier would require higher-priced bids to be addressed in a contested case, which would take longer, he asserted that this may result in a more competitive and scrutinized bidding process.[172] On the other hand, he opined that if the Commission approves ex parte approval up to 140% LCOE, there is a risk developers will bid higher to garner more profits, which could substantially increase costs.[173] For these reasons, Mr. Richter proposed the Commission reject the Company's proposal or approve a smaller multiplier of 110.4% for solar and no multiplier for wind based on LevelTen's renewable energy price tracking.[174] If the

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[167] 4 Tr 560-562.
[168] 4 Tr 562.
[169] Id.
[170] 4 Tr 563.
[171] 4 Tr 564.
[172] Id.
[173] Id.
[174] 4 Tr 565-566.

Commission approves ex parte approval of projects with an LCOE above these amounts, he requested the Commission limit the duration of its approval and require this issue to be revisited in the Company's next REP case.[175]

GLREA witness Rafson testified that Consumers proposes only build-transfer for solar, which is a higher cost option than third-party PPAs, and takes this proposal "to an extreme with the request to allow up to 140% of an already high transfer price."[176] He claimed the Company is proposing a solar LCOE of more than double the national average.[177] He argued that a 40% increase in contract costs should not simply be approved but should be subject to a thorough review using the contested case process and "phantom risks" should not be addressed until they actually occur.[178]

MEIU did not completely oppose the Company's proposal but requested that the Commission condition its approval "on the use of a fair and transparent bidding framework."[179] Mr. McDonnell testified that he generally supports "steps that could alleviate the administrative burden on the Commission, its Staff, the Company, and any third-party bidder under a potential PPA to facilitate timely approval of procurements" and acknowledged that an ex parte contract approval process "may assist in that objective."[180] However, he expressed concern that the Company's procurement process "lacks sufficient elements and safeguards that would ensure a competitive and fair process."[181] He argued that "reduced scrutiny at the approval stage should only be justified by more

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[175] 4 Tr 566.
[176] 4 Tr 618.
[177] 4 Tr 619-620.
[178] 4 Tr 620.
[179] 4 Tr 637-638.
[180] 4 Tr 655.
[181] Id.

robust processes in the earlier stages of procurement."[182] Therefore, to ensure a fair and transparent bidding framework, he recommended that the Commission grant the Company's request for an ex parte approval process if the following conditions are included:

- The use of a competitive bidding process overseen by an IA;
- A mandated 50/50 ownership split between the Company and third parties;
- A mid-size (1-5 MW) procurement carveout to comprise up to 10% of total new solar resources; and
- A process to periodically revisit the Company's LCOE targets for wind and solar energy resources.[183]

Mr. McDonnell described the use of an IA as important because the IA "(1) oversees the procurement process, (2) conducts the evaluation and scoring of proposals, and (3) communicates its results to the utility in an anonymous manner for a utility to choose the comprehensively best partner for resource procurement."[184] Mr. McDonnell emphasized that even if an IA-administered competitive procurement process is not used, it is critical that the Company be required "to make all commercially reasonable attempts to maintain a 50/50 ownership split for new renewable resource procurements."[185] Mr. McDonnell explained that without this requirement, the Company's preference for Company-owned resources, an "unrestricted ex parte contract approval process may result in the procurement of more expensive, solely Company-owned resources."[186] He opined that "the combination of a 50/50 ownership split with an ex parte contract approval

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[182] Id.
[183] 4 Tr 656.
[184] 4 Tr 657.
[185] 4 Tr 657-658.
[186] 4 Tr 656-657.

process is mutually beneficial because third-party-owned assets have the potential to lower energy costs, while ex parte approval of contracts should allow for such assets to be contracted for and interconnected in a more expeditious fashion."[187]

Finally, Mr. McDonnell testified that the LCOE targets should be revisited as changes in the LCOE applicable to a resource type may impact whether a project is economically viable.[188] He noted that the Company's wind and solar LCOEs are higher than the LCOEs that would be determined using the overnight capital costs as estimated by the NREL in its 2024 Annual Technology Baseline (ATB).[189] He maintained that even if the Company's wind and solar LCOE assumptions are correct, "their divergence from national LCOE scenarios suggests that such targets should be revisited on a regular cadence to ensure that ratepayers are not unduly exposed to a resource portfolio procured under inflated cost assumptions."[190] He also noted that that the renewable energy development landscape is dynamic and fast changing. For these reasons, he recommended that the LCOE targets be updated every two years or at the filing of each subsequent REP.[191]

Mr. Johnston responded to Mr. Deupree by clarifying that the Company is not trying to avoid due diligence or execute every new contract at 140% of the baseline LCOE but is seeking to expedite and provide flexibility with respect to the regulatory approval process.[192] He maintained that, "the Company is fully aware of the potential affordability

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[187] 4 Tr 657-658.
[188] 4 Tr 660.
[189] Id.
[190] 4 Tr 660-661.
[191] 4 Tr 661-662.
[192] 2 Tr 100.

impact of its amended RE Plan on its customers and believes that its amended RE Plan helps to balance those potential impacts by not imposing a revenue recovery mechanism."[193] He also disagreed that the Company's baseline LCOE estimates are too high, noting that an IA oversees the Company's solicitations and the Company has not received any proposals close to the LCOEs discussed by Mr. Deupree.[194] He noted that Mr. Deupree's opinion was based on EIA Region 5, which covers not only Michigan, but Illinois, Indiana, Minnesota, Ohio, and Wisconsin, all of which may have different siting availability, underlying construction costs, and interconnection requirements.[195]

Mr. Johnston refuted Mr. Jester's and Mr. Richter's claims that the Company did not provide evidence to support the 140% LCOE threshold. He stated that supporting materials were provided during discovery and he presented exhibits containing supporting materials, including workpapers that calculated removal of the tax credits would result in an increase in the LCOE of 37% for solar and 48% for wind and an analysis that ranked the results of the Company's 2023 IRP solicitation based on the solicitation criteria, which revealed that the marginal project required to achieve the Company's 500 MW target came in at a threshold multiplier of 139%.[196] Mr. Johnston emphasized that rejection of the proposed threshold would require contested case approval of renewable energy projects, which would cause a delay in project approval and implementation that would unnecessarily hamper the Company's ability to comply with the RPS.[197]

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[193] 2 Tr 101.
[194] Id.
[195] Id.
[196] 2 Tr 98; Ex.A-44; Ex.A-45; Conf. Ex. A-46.
[197] 2 Tr 99.

He pointed out that MEC-NRDC's position conflicts with its other recommendations, such as revising the transfer price calculation to allow for an increase in the amount of cost transferred through the PSCR and accelerating the buildout of wind energy (which rejection of the 140% threshold would decelerate), disallowing REC-only contracts, and modifying the incentive REC criteria with respect to peak time.[198]

As to GLREA witness Richter's assertion that the Company does not believe its LCOE calculations for wind and solar are accurate, Mr. Johnston stated that it's models "were well founded and reflect current reality, that tax credits are still available, and tariffs have not significantly impacted the cost of renewable energy equipment."[199] Mr. Johnston agreed with Mr. Richter's recommendation that ex parte approval should only extend until the next amended REP, noting that "Mr. Richter makes sound observations regarding the necessity of the multiplier and the likely response by developers to the multiplier within competitive solicitations," and that the Company does not intend to execute all future renewable energy resource projects at the 140% LCOE threshold.[200]

Mr. Johnston responded to GLREA witness Rafson by stating the Company is not solely considering build-transfer solar, is continuing to target a 50% ownership split for its solar resources as established in Consumers' 2021 IRP, and will select the most economically beneficial projects for its customers.[201] Mr. Johnston disagreed that the Company's LCOEs are too high and its 140% threshold extreme, again stressing that the Company's LCOE is based on recent solicitations and reflects potential risks for which it

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[198] 2 Tr 99-100.
[199] 2 Tr 105.
[200] 2 Tr 105-106.
[201] 2 Tr 103-104.

is prudent to plan and that the 140% threshold is to allow the flexibility necessary for the Company to comply with the increased RPS.[202] He asserted that it would be both unreasonable and imprudent to fail to plan for various risks, especially if the outcome is the Company's failure to achieve REC compliance.[203]

In response to MEIU's recommended conditions on ex parte approval, Mr. Cole noted that Consumers "currently utilizes IAs as part of its competitive procurement processes and has no intention of altering this practice."[204] Mr. Cole also agreed that its wind and solar LCOE targets should be regularly updated and indicated that the Company would update these targets in each of its subsequent REP amendments.[205]

However, for the reasons discussed by Mr. Johnston as described in the Company-Owned Wind Energy Resources section above, Mr. Cole did not support requiring a mandated 50/50 ownership split between the Company and third parties.[206]

In rebuttal, Staff disagreed with the intervenors and supported the Company's proposal for ex parte approval up to 140% of the LCOE as proposed by the Company. Mr. Harlow pointed out that "[t]he Commission has provided ex parte review and approval of both PPA and Company-owned renewable energy contracts since the first REPs were approved in 2009."[207] He explained that ex parte approval allows expedited contract approval of less than 90 days as opposed to over a year, which reduces regulatory risk for renewable developers by ensuring that projects will not be tied up in litigation for

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[202] 2 Tr 103.
[203] 2 Tr 104.
[204] 2 Tr 363.
[205] 2 Tr 365.
[206] 2 Tr 363.
[207] 4 Tr 811.

extended periods of time thus costing "time and ultimately money (such as interest on loans, lease payments, and litigation expenses)."[208] Without ex parte approval, he expressed concern that developers would include a risk premium in future bids or not bid at all and noted that a longer approval process would similarly increase the cost of Company-owned projects because of interest on regulatory balances, lease payments, and inflation.[209]

Mr. Harlow was not concerned that the 140% of LCOE upper limit is too generous an allowance. He clarified that the 140% does not represent the actual costs projected or a contingency allowance for cost overruns and that "[a]ctual costs are reviewed and scrutinized through contract review request applications filed by the Company with the Commission, in which Staff audits the RFP process, proposals submitted in response to the RFP, and Company scoring methodologies before making a recommendation on that contract to the Commission."[210] Rather the 140% is in place for planning purposes to enable expedited ex parte contract review even if cost increases occur due to revocation of federal tax credits (which alone could cause an approximately 30% increase in costs), implementation of tariffs (which is not entirely unlikely), or other reasons.[211] He concluded that not building in a reasonable price range could impact the Company's ability to meet the RPS and result in contested case proceedings being required for contract approval. However, Mr. Harlow did recommend that future REPs tie the upper cost limit to the upper cost limit included in the most recently approved IRP and vice versa.[212]

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[208] Id.
[209] 4 Tr 812.
[210] 4 Tr 812-813.
[211] 4 Tr 813.
[212] 4 Tr 813-814.

Regarding the conditions on ex parte approval recommended by MEIU, Mr. Harlow disagreed that, absent these conditions, the Company would forgo its current strategy of annual RFPs that include the option for third-party PPAs, and construct only Company-owned renewable assets.[213]

In rebuttal, GLREA witness Richter testified that, to his knowledge, the Commission has not granted permission for ex parte approval of contracts so materially more expensive than the target LCOE and maintained that Consumer's request is unprecedented and unjustified.[214] He reiterated that the actual solicitation numbers did not support that Company's claim that it received fewer solar MWs than the intended 500 MW per annual solicitation and remarked that Staff failed to address this inconsistency.[215] Mr. Richter also asserted that Consumers' discovery responses reflect that the Company considers a competitive price to be one that may be approved without the inconvenience of a contested case regardless of the affordability of the contract, which undermines Consumers' justification for ex parte approval.[216] In addition, he reiterated his direct testimony that the Company's proposal is unsupported by evidence and the duration of the permission sought by the Company is not clear.[217]

In its brief, GLREA points out that after rebuttal testimony was filed, the U. S. House of Representatives Ways and Means Committee unveiled a bill that would quickly phase out the federal tax credits for solar and wind facilities.[218] Consequently, GLREA

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[213] 4 Tr 811-812.
[214] 4 Tr 594-595.
[215] 4 Tr 595-596; Ex. GLREA-3, p. 3.
[216] 4 Tr 596-597; Ex. GLREA-3, pp. 3-5.
[217] 4 Tr 598.
[218] GLREA initial brief, pp. 6-7.

recommends that the Commission direct the Company to modify their solicitation process to address this risk, by asking bidders to supply a quote with two prices: the "standard price" on bids would assume the tax credits continue and an additional "contingency price" would be applicable if the federal tax credits were repealed.[219] GLREA suggests that contracts with a "contingency price" up to 140% of the Company's target LCOE could receive ex parte approval.[220] GLREA emphasizes that the Commission should not wait for developers to request a change to the RFP language on conforming bids, as Company witness Cole suggested.[221] GLREA recommends 110.4% LCOE for solar facilities as a "standard price" ex parte approval threshold, but states that if Commission does not wish to modify the solicitation process to include a federal tax credit repeal "contingency price", then they suggest that the Commission approve the four process modifications recommended by MEIU.[222]

In her brief, the Attorney General argues that the Company has failed to demonstrate that a140% LCOE is a necessary cost adder or that passing on administrative costs to ratepayers is reasonable or prudent. She notes that under MCL 460.6a(3), a request for ex parte relief requires that the outcome of the request "will not result in an increase in the cost of services to [utility] customers and yet the Company admitted that it did not model the financial impact of the 140% multiplier.[223] The Attorney General takes issue with Company witness Johnston's rebuttal challenging the reasonableness of the LCOEs cited by Attorney General witness Deupree. She argues

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219 Id at p. 7.
220 Id.
221 Id.
222 Id at pp. 8-9.
223 AG initial brief, pp. 24-25.

that EIA's AEO is a public forecast that the Commission has recognized as appropriate in the past as estimates of future natural gas prices within IRP modeling.[224]

In its brief, MEC-NRDC also refers to MCL 460.6a and cites Case No. U-15161 and Case No. U-21189 as holding that any utility request that may increase rates or charges cannot be approved without notice and an opportunity for hearing.[225] MEC-NRDC claims that cross examination showed that the projects that Consumers has recently been submitting for approval are all far under the 140% threshold, and in line with the estimate from the IRP:

- Spring Creek Solar, a 140 MW project presented in this case from the 2022 IRP solicitation: LCOE of $56.55 per MWh.
- Muskegon Solar, a 250 MW project presented in this case from the 2022 IRP solicitation: LCOE of $51.51 per MWh.
- Freshwater Solar, a 300 MW project approved in Case No. U-21090 from the 2022 IRP solicitation: LCOE of $63.29 per MWh.
- Heartwood Solar PPA amendment, a utility-scale (over 50 MW) project approved in Case No. U-20165: LCOE of $52.67 per MWh.
- Jackson County Solar PPA amendment, a utility scale project approved in Case No. U-20165: LCOE of $58.32 per MWh.
- Karn solar, an 85 MW project pending in Case No. U-21374: LCOE of $59 per MWh.
- Sunfish 2, a 309 MW project approved in Case No. U-21409: LCOE of $52.69 per MWh.[226]

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[224] Id at pp. 26-27.
[225] MEC-NRDC initial brief, pp. 44-45.
[226] Id at pp. 47-48.

MEC-NRDC also contends that the Company's evidence that the marginal bid in the last solicitation was 139% above their target price, was based on a small 5 MW system, which is completely atypical of bids.[227] Further, MEC-NRDC states that the Company admitted in cross that historically, contested cases for contract approval did not result in extensive delays, as settlements were commonly reached.[228] As for MEIU's recommendations, MEC-NRDC opines that they are "plainly intended to serve the commercial interest of MEIU's member companies – who wish to sell PPAs and projects to Consumers."[229]

In reply, MEIU says MEC-NRDC's "ad hominem attack on MEIU witness McDonnell's recommendations" is "misplaced, unwarranted and inaccurate" and that "[i]n the presence of a competitive marketplace, a 140% LCOE ex parte threshold cap provides no cost- or revenue-related benefit to MEIU's member companies other than administrative efficiencies following a winning—and competitive—bid.[230]

This PFD find's Staff's reasoning and recommendations pertaining to the Company's proposed 140% of LCOE threshold for ex parte approvals to be reasonable. This PFD does not discount the concerns raised by the intervenors that the 140% threshold is too high but finds that Consumers supported its 140% LCOE multiplier as being necessary to mitigate the regulatory risks surrounding new renewable projects and enable it to meet Act 235's RPS targets. As explained by Staff and Consumers, and generally noted by GLREA, the current energy landscape, particularly as to inflation and

[227] Id at p. 49.
[228] Id at pp. 49-50.
[229] Id at p. 52.
[230] MEIU reply brief, p. 7.

the availability of federal tax credits for wind and solar, is creating uncertainty and risk for developers. This PFD finds persuasive Staff's explanation that the actual costs of these projects will still be reviewed and scrutinized by the Commission.

While this PFD recognizes the Attorney General's and MEC-NRDC's references to MCL 460.6(a)(3), this PFD nevertheless notes that the statute specifically provides that "[a]n alteration or amendment in rates or rate schedules applied for by a public utility that will not result in an increase in the cost of service to its customers may be authorized and approved without notice or hearing" and finds that approving the 140% LCOE is not contrary to the statute.

This PFD concurs with MEIU's recommendations that ex parte approval be contingent upon the Company's use of an IA in its RFPs and that the wind and solar LCOE targets should be regularly updated, as the Company has agreed with both of these conditions. However, as discussed above, as long as the Company is actively soliciting third party PPAs in its RFPs, a strict 50/50 ownership split is unwarranted.

Based on the foregoing, this PFD recommends that the Commission approve the Company's request for ex parte approval of wind and solar contracts up to 140% LCOE, conditioned on the use of an IA and conditioned on the Company updating its LCOE targets, or cost assumptions, every two years in the filing of each REP.

4. Transmission Studies

GLREA witness Rafson recommended that Consumers should be directed to work with MISO to determine if transmission lines will support the proposed generation assets

in the amended REP, and the results should inform capacity and location on existing lines as well as the need for any transmission upgrades.[231]

In rebuttal, Company witness Clark testified that Mr. Rafson's recommendation is unnecessary as the MISO Generator Interconnection Process (GIP) determines the upgrades needed to support each proposed generation asset.[232] He added that the GIP culminates in an executed Generator Interconnection Agreement (GIA) which outlines the requirements and obligations for the proposed generation asset to interconnect to the transmission grid, including the any needed upgrades.[233]

This PFD agrees with Consumers that the Company already works with MISO through the GIP to ensure that proposed generation can be supported or whether upgrades are needed. Therefore, this PFD declines to adopt GLREA's recommendation.

5. Renewable Resource Acceleration

GLREA witness Richter testified that there are a number of risks associated with Consumers build plan for new renewables that could be addressed in various ways including front-loading its REP with more capacity earlier than scheduled. According to him, "[t]his will slightly increase the cost (due to the time-value of money), but will allow for some schedule slippage."[234] Mr. Richter elaborated that if planned resource additions are scheduled to meet statutory compliance deadlines, any delay in a project could result in Consumers being out of compliance with the RPS. By starting projects well ahead of time, there is some "slack" in the event of schedule slippage.[235]

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[231] 4 Tr 614.
[232] 2 Tr 230
[233] Id.
[234] 4 Tr 577.
[235] 4 Tr 578.

Mr. Richter opined that it does not appear that Consumers has front loaded its renewables build plan, noting that the plan appears based on the settlement agreement in the Company's IRP, which forecasts the addition of 500 MW of solar per year from 2027 through 2040. According to him, "[a] front-loaded build plan would acquire more capacity in earlier years and less in later years."[236] As such, Mr. Richter recommended that the Commission direct Consumers to build or acquire projects in excess of 500 MW per year, if the pricing is reasonable and the project will be in service before the next increase in the RPS.[237]

In rebuttal, Mr. Johnston explained that it is a possible strategy to accelerate the build out of renewables to ensure RPS compliance. However, pointing to Confidential Exhibit A-46, he noted that the front loading recommended by Mr. Richter may be difficult without the 140% LCOE threshold discussed above.[238] Mr. Johnston further explained that in any event, "[the Company] is not limiting the consideration of renewable energy projects to 500 MW. The only limitation is an ability to acquire sufficient projects which are economic."[239]

In its brief, MEC-NRDC echo the need for acceleration in the acquisition of new renewables, particularly in connection with wind resources.[240] In its brief, GLREA states:

> We are reassured by the Company's response, and note that a project's schedule becomes less important by front-loading the plan with more capacity. We recommend that the Commission's order in the instant case specifically signal the Commission's willingness to approve contracts for

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[236] *Id.*
[237] 4 Tr 590.
[238] 2 Tr 107.
[239] 4 Tr 108.
[240] MEC-NRDC initial brief, 8-10.

more than the Company's planned 500 MW per year, if they are cost-competitive.[241]

This PFD finds that the Company indeed appears to be willing and able to exceed the 500 MW per year projection for resource acquisition, provided the projects are economical. As such, the PFD does not find it necessary for the Commission to order Consumers to adjust its current practice.

C. Sales Forecast

Mr. Breuring presented the Company's electric retail sales forecast for 2024 through 2045, which includes bundled sales to residential, commercial, industrial, streetlighting, and inter-departmental classes, and which excludes wholesale, intersystem, and choice sales.[242] As shown in Exhibit A-6, the Company forecasted 3,792,124 MWh in sales to Industrial Large Economic Development (LED) customers in 2028, which increases to 8,667,407 MWh in 2045. Mr. Johnston attributed this significant increase in LED sales to accelerated growth in data centers needed to support artificial intelligence.[243] Mr. Obikwelu used Mr. Breuring's sales forecast to project REC targets for 2023 through 2045, as set forth in Exhibit A-33.

Noting the significant increase in sales due to projected data center growth, Mr. Deupree recommended that any additional load forecasted after 2028 for Industrial LED customers should be removed from the REP and not be used to calculate REC compliance.[244] According to him, Consumers' near-term (2024-2028) forecast for increased LED sales is reasonably reliable because it is based on signed contracts with

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[241] GLREA initial brief, 11.
[242] 2 Tr 203-204; Ex. A-6.
[243] 2 Tr 46-47.
[244] 2 Tr 471.

customers.[245] However, for the post-2028 projection, Mr. Deupree opined that given the lack of support for the outyear forecast, "it is premature at the current time to include these loads when the Company cannot clarify how much of its additional load growth is associated with publicly announced projects versus private inquiries that are subject to change or outright cancellation."[246] Mr. Deupree added that Act 295 requires the Company to update its REP every two years, so additional LED load can be included in these future filings.

In rebuttal, Mr. Johnston testified that Consumers prepared its forecast based on the best information available at the time of filing, and to reduce the long-term sales forecast, as Mr. Deupree suggests, would be "negligent."[247] Mr. Johnston stated:

> Act 235 established a significant step change in the REC compliance target in 2030 and a failure to plan for that accordingly will likely result in failure to comply. The Company will file another amended RE Plan within two years of a final order in this proceeding and it can certainly adjust its delivery forecast downward at that time. Further, the Company will be filing its next IRP in June 2026 and will assess its REC compliance requirement at that time as well.[248]

Mr. Johnston further explained that Consumers is far more concerned with REC compliance than it is with the potential overbuild of renewable resources and that the Company's IRP glidepath for additional solar and wind provides for significant flexibility if projected sales additions do not occur.[249]

CEO witness Shaver observed that Exhibit A-6 forecasts Consumers' overall load growth, primarily driven by Industrial LED increases, of approximately 4% from 2024 to

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[245] 2 Tr 470-471; Exhibit AG-1.12.
[246] 2 Tr 471.
[247] 2 Tr 93.
[248] *Id.*
[249] 2 Tr 93-94.

2031.[250] He characterized this as a relatively high-growth scenario compared to forecasts from NREL and MISO.[251] Mr. Shaver opined that the largest risk the Company faces is that load growth will outpace renewable energy development, especially in the later years of the REP. As such, "it is critical to develop robust and early planning which addresses a range of scenarios."[252]

Given the uncertainty of future load growth, and the risks inherent in either over or under development of renewable resources in the future, Mr. Shaver recommended that in its next IRP, Consumers develop a range of load growth scenarios, based on the Company's own data as well as publicly available information from various sources.[253] He also commented that while Mr. Deupree "may be correct in questioning the current evidence for specific loads beyond 2028 . . . [i]f Consumers only plans for this future load growth based on the two year cycle of the REP process, there is significant risk that as load materializes the Company will not be able to meet its RPS obligations."[254]

In rebuttal, Mr. Johnston agreed that a range of load growth scenarios should be modeled in the Company's next IRP, but disagreed that this is the proper forum for establishing IRP modeling requirements.[255] According to him, "[t]hose proposals can be addressed in various activities pursuant to Case No. U-21570 and/or through the Company's planned IRP stakeholder outreach."[256]

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[250] 4 Tr 699-700.
[251] 4 Tr 701.
[252] 4 Tr 701.
[253] 4 Tr 703-704, 711.
[254] 4 Tr 713.
[255] 2 Tr 96.
[256] 2 Tr 97.

In briefing, Consumers relies on the testimony of its witnesses, reiterating that although examination of various load growth scenarios should be part of the IRP, this case is not the proper venue for considering IRP modeling requirements.[257]

In her brief, the Attorney General maintains that the Company's long-term load forecast was insufficiently supported. Nevertheless, she withdrew her recommendation to remove post-2028 RECs from the REP and instead adopts the recommendation of CEO witness Shaver that Consumers evaluate a range of growth scenarios in the Company's next IRP.[258] However, the Attorney General disagreed with the Company's position that IRP modeling requirements should not be addressed in this proceeding, arguing that:

> Given the significance of the new industrial load forecasted by the Company and its apparent inability to explain its longer-term projections in this matter, the Commission should require the Company to file a more robust analysis as part of its 2026 IRP plan application.[259]

In their reply brief, the CEO similarly assert that:

> The Commission should reject the Company's unsupported contention that it lacks authority to order IRP requirements in this proceeding. The Company provides no legal support for this position. The Company cites no caselaw or statute that limits the Commission's authority. There is no reason that the Planning Parameters docket must be the exclusive means to order analyses to take place in the IRP. Relatedly, if the Commission chooses to do so, it may implement the CEO's recommendations within the planning parameters docket for all Michigan utilities. The CEO also note that Consumers' concerns around the CEO's recommendations applying only to the Company are obviated by the Commission's adoption of a settlement agreement in the DTE REP case, U-21662, which includes terms on load forecasts and curtailment. See Case No. U-21662, Order Approving Settlement (May 15, 2025).[260]

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[257] Consumers initial brief, 24-26.
[258] AG initial brief, 43.
[259] AG initial brief, 44.
[260] CEO reply, 2-3.

As an initial matter, this PFD agrees with the CEO that the Commission has the authority to direct the Company to model various load forecasts as part of this REP proceeding. However, contrary to the CEO's claim, Consumers never asserted that the Commission did not have such authority, only that it would be more reasonable to address modeling requirements in another forum, namely the Company's next IRP.

The Company's position is in general agreement with the CEO regarding the need for various load growth scenarios, and this PFD agrees with Consumers that the sales forecast presented here is reasonable; it complies with the requirements of Act 295, and the forecast can be adjusted over time in IRP and biennial REP filings. Further, this PFD concurs with the Company that various load growth scenarios applicable to all regulated utilities should be established as part of IRP filing requirements that are being updated in Case No. U-21570.

D. Transfer Price

The Company proposes continuing the current Transfer Price and deferred accounting for Company-owned assets in the REP through December 2045.[261] The Company also proposes simplified transfer price schedules to replace those approved Case No. U-15805 and Case No. U-16581.[262]

Mr. Cole summarized the renewable energy resources recoverable through the transfer price mechanism included in the REP as:

> This plan includes a total of 8,104 MW of solar projects which would be recoverable via the transfer price mechanism. Of that, 504 MW are solar projects already in the RE plan and 690 MW are due to the moving of IRP assets into the RE plan. The remaining 6,910 MW are unnamed proxy solar

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[261] 2 Tr 325.
[262] Id.

> projects, which includes 1,060 MW of unnamed proxy solar VGP projects. The additional 1,060 MW of proxy solar VGP projects combined with the existing 398 MW of named solar VGP projects and the 120 MW of named VGP wind projects brings the total VGP size to 1,578 MW. Additionally, this plan includes a total of 2,800 MW of unnamed proxy wind projects and 1,200 MW existing wind projects recoverable via the transfer price mechanism. Finally, this plan includes 20 MW of existing resources that are not wind or solar technologies which are recoverable via the transfer price mechanism.[263]

Mr. Cole testified that the Company included a portion of the costs incurred in implementing its REP in the Company's 2025 PSCR Plan proceeding pursuant to MCL 460.1047(2)(b)(iv) and that these costs are expected to be recovered through the transfer price, or transfer cost.[264] He explained that the transfer cost is "the total cost that the Company will transfer to power supply costs in accordance with MCL 460.1047(2)(b)(iv) associated with renewable generation obtained in accordance with MCL 460.1047."[265] Mr. Cole noted that the transfer price was defined by the Commission in the Temporary Order issued in Case No. U-15800.[266] He presented detailed information about the Company's anticipated renewable energy generation through 2045, which would be included in the Company's transfer price.[267] Consumers' forecasted Transfer Price for the period 2024 through 2045 is estimated to be $72.67/MWh.[268]

Mr. Cole testified that the Company is not proposing any changes to the transfer price that is currently in place, stating that:

> While the Company's modeling assumes that no costs from the Renewable Energy Program renewable energy resources will be transferred to the PSCR via the transfer price mechanism, the modeling does indicate that the

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[263] 2 Tr 328-329.
[264] 2 Tr 332.
[265] Id.
[266] 2 Tr 335-336; December 4, 2008 order in Case No. U-15800, pp. 25-26.
[267] 2 Tr 332-335; Ex. A-24 through A-28.
[268] 2 Tr 337.

> original transfer price mechanism that was re-established in Case No. U-20483 needs to continue to remain in place to maintain a regulatory liability balance. Through the renewable energy cost reconciliation filings, the Company has previously committed to returning to limiting transfer price to the levelized cost of energy ("LCOE") for Company-owned facilities when the risk of dipping into a regulatory asset position is low. As a result of Michigan's Act 235, the Company is proposing to return to limiting transfer price to the LCOE for Company-owned facilities starting in 2034 and continuing for the remainder of the plan period. The modeling in this proceeding is based upon a return to that transfer price methodology beginning in 2034. The Company will continue to report on the status of the regulatory account balance in its annual renewable energy cost reconciliation proceedings.[269]

Mr. Cole explained that transfer price was originally established in the Act in 2008 PA 295 and that "transfer price schedules should be representative of what a Michigan electric provider would pay had it obtained the energy and capacity (the non-renewable market price component) through a long-term power purchase agreement for traditional fossil fuel electric generation."[270]

According to Mr. Cole, Consumers is proposing new, simplified, transfer price schedules to reduce the administrative burden, and reduce potential errors, associated with the existing transfer price schedules for 12 renewable facilities.[271] The Company is also proposing to assign the Lake Winds Energy Park, and Lake Winds Energy Park Repowered projects to its own unique Transfer Price schedule.[272] Mr. Cole explained that the existing Transfer Price schedules from Case No. U-15805 and Case No. U-16581 include a monthly on-peak rate, monthly off-peak rate, and monthly capacity rate, but Staff 's recently proposed Transfer Price schedules that do not include a capacity rate

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[269] Id.
[270] Id.
[271] 2 Tr 338-339.
[272] 2 Tr 339.

and include only a yearly total $/MWh rate.[273] According to Mr. Cole, the Company's proposal is simpler, would reduce administrative burdens and potential errors, and would align with Staff's proposed schedules.[274]

Mr. Cole testified that the new transfer prices are based on the existing Transfer Price schedules applicable to the units and that it is similar to a weighted average of the on-peak/off-peak and capacity transfer rates based on the resource pool's generation profile/capacity accreditation.[275] He explained further that the new schedules were created with the primary goal of reducing the impact to the total cost transferred to PSCR via the transfer price and that the newly proposed schedules result in an estimated net total decrease of only $20 when compared to the existing schedules, which is insignificant.[276] He acknowledged, however, that there are variables that may change how closely the new schedules follow the existing schedules, the biggest factor of which is the on-peak/off-peak generation split.[277] He explained that the new schedules were created using a three-year historical average of generation during on-peak and off-peak hours, and a divergence of the total transfer cost could occur if a unit significantly strays from its historical on-peak/off-peak energy production (including outages).[278] Mr. Cole asserted that the Company created these new transfer price schedules because it could not simply assign these units to Staff's latest transfer price schedule since it is important to use

[273] Id.
[274] Id.
[275] 2 Tr 339-340.
[276] 2 Tr 340-341; Ex. A-31.
[277] 2 Tr 341.
[278] Id.

transfer price schedules that are created in a relatively similar timeframe to when the facilities are brought online.[279]

MEC-NRDC recommends that the Commission disapprove Consumers' proposed schedule of transfer prices, direct that Consumers' transfer price schedule be addressed in the Company's renewable energy reconciliation case and provide guidance that the new schedule must include the costs of carbon capture and storage if it continues to be based on a proxy natural gas-fired generating plant.[280]

MEC-NRDC witness Jester explained that the Michigan clean energy standards added by Act 235 require a clean energy system that is fueled by natural gas to be at least 90% effective in capturing and permanently storing carbon dioxide[281] and that the new Environmental Protection Agency (EPA) greenhouse gas emissions rule[282] requires "new combined cycle gas plants with annual capacity factors greater than 40 percent [to] be equipped and operated with 90% effective carbon capture, effective January 1, 2032."[283] Therefore, according to Mr. Jester, "the transfer price based on a combined cycle gas plant must account for the costs of carbon capture and storage."[284] Mr. Jester recommended that the Commission adopt an incremental addition to the Company's proposed transfer prices in this case that is equal to the cost of compliance estimated by the EPA in 2019 dollars, adjusted for inflation.[285] As Staff's transfer price method is based

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[279] 2 Tr 341-342.
[280] MEC-NRDC initial brief, p. 54.
[281] MCL 460.1003(i)(*ii*).
[282] Environmental Protection Agency, *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule*, 89 FR 39798 (May 9, 2024).
[283] 2 Tr 402-403.
[284] 2 Tr 403.
[285] 2 Tr 404.

on a 400 MW capacity combined cycle plant (NGCC), he proposed using the EPA's $19/MWh estimate for a 700 MW F-Class turbine and increasing this amount by 19.3% to account for inflation from 2019 to the present based on the United States Bureau of Economic Analysis Personal Consumption Expenditures Price Index. This results in an incremental addition for the estimated cost of carbon capture and storage of $22.66/MWh.[286] Mr. Jester noted that his proposed increase in the transfer price will substantially reduce the incremental cost of compliance, which will in turn lead to lower regulatory asset or higher regulatory liability balances.[287]

GLREA witness Rafson testified that it is not reasonable to retain a methodology that might have encouraged renewable energy development when it was created in 2008, but is no longer reasonable since renewable energy generation is now the lowest cost generation technology.[288] He maintained that the transfer price assigned to a generation asset should only cover its actual construction costs, while for PPAs, the Company should pay for the cost of energy negotiated plus the cost/value of the RECs or more simply competitively bid for renewable energy assets with RECs included.[289] He recommended an alternative method stating that "the REP and IRP in the past has been used to develop a plan and in the short term to propose shovel ready projects to build with the Commission overseeing the bidding process and to consider recovery of construction costs in the rate cases."[290]

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[286] Id.
[287] 2 Tr 405.
[288] 4 Tr 617.
[289] 2 Tr 617-618.
[290] 2 Tr 618.

ABATE witness York expressed concerns that if the transfer price schedules are changed to eliminate the capacity component, it is unclear how the Company would maintain the appropriate classification of costs for the assets to which the new Transfer Price schedules would be applicable, when those costs are reflected in the PSCR in a base rate case.[291] She opined that given that the costs of renewable resources are largely fixed costs and those resources contribute toward meeting the Company's capacity needs, it would be entirely inappropriate to cease classifying a portion of these costs as demand-related when they are reflected in the PSCR in a base rate case.[292] If the current method of determining the split between energy and demand portions of the transfer price is changed, she proposed that the proportion of demand-related costs be maintained.[293] She also expressed concerns that the new transfer price schedules would impact the amount of renewable costs projected to be transferred to the PSCR.[294]

ABATE opposes MEC-NRCD's proposal to adopt a transfer price based on an NGCC with carbon capture and storage, arguing that transfer prices are required by statute to be established in reconciliation proceedings, the proposal will dramatically increase costs, and it is unreasonable and premature.[295] ABATE states that if the transfer price methodology is to be revisited it should be done carefully with the essential transparency the Commission sought to ensure when first ordering Staff to consider this issue.[296]

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[291] 4 Tr 727.
[292] Id.
[293] Id.
[294] 4 Tr 728.
[295] ABATE initial brief, pp.3-14.
[296] Id at p. 14.

Mr. Cole also disagreed with MEC-NRDC's proposal to modify the transfer price, stating that including carbon-capture in the transfer price would translate into transferring the costs associated with clean energy (rather than non-renewable energy) to the PSCR and while this might make sense in light of Act 235, it does not align with the current Staff methodology for transfer price schedules.[297] Mr. Cole stated that changes in the transfer price should be accomplished in a workgroup, the same way they were initially developed.[298] Consumers also notes GLREA's disagreement with the Company's decision to continue using the Commission's transfer price methodology, but states that any changes be accomplished via a workgroup with the participation of all utilities.[299]

Staff witness Harlow supported the Company's plan to retain the transfer price mechanism to maintain a regulatory liability balance and return to limiting the transfer price to the LCOE for Company-owned facilities starting in 2034, with the caveat that it be used to calculate the incremental cost of compliance for planning and that ultimately, transfer prices for cost recovery are adjusted and approved in annual reconciliations.[300]

Mr. Harlow also testified in support of Consumers' modified transfer price schedule and opined that it is "a much simpler and transparent transfer price schedule than the Company's existing transfer price schedule that is applied to Lake Winds Energy Park."[301]

As for MEC-NRDC's recommendation that the transfer price methodology must be based on an NGCC with carbon capture and storage, Mr. Harlow agreed that Staff's transfer price methodology could be reviewed or reevaluated at this time if the

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[297] 2 Tr 361-362.
[298] 2 Tr 362.
[299] Consumers initial brief, p. 31.
[300] 4 Tr 795.
[301] 2 Tr 797.

Commission were to think it is appropriate, but he disagreed that Staff's current method is flawed or that it should be updated outside of a process that properly notices all parties affected by the transfer price, such as all rate-regulated utilities.[302] He opined that the use of a NGCC, even in light of PA 235's clean energy standards, is not necessarily incorrect.[303] He explained that Staff's transfer price methodology is representative of what a Michigan electric provider would pay if it were to obtain energy and capacity from the market through long term PPAs and that it is assumed that the PPA prices would converge towards the market pricing set by an NGCC.[304] He added that while there is a locational component to MISO market pricing, the energy and capacity market is not clearly defined by state borders or state policies and it would be hard to absolutely define what impact Michigan's clean energy laws will have on future energy and capacity prices through all of MISO and if future PPAs will converge towards the price of a NGCC with carbon sequestration or remain close to that of a traditional NGCC. [305] He concluded that due to the uncertainty around the future of natural gas generation and what impact these changes may have on market pricing, it is premature to make changes to the transfer price proxy plant, as proposed by MEC-NRDC.[306] He also remarked that MEC-NRDC's proposal would have no impact on the method for cost recovery of renewable energy for PPAs as Section 47 requires the lesser of a PPA or the transfer price be recovered via the PSCR mechanism, while the recommendation would result in a significant increase in the amount recovered through the PSCR for Company-owned facilities and greatly

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[302] 4 Tr 804.
[303] Id.
[304] Id.
[305] 4 Tr 804-805.
[306] 4 Tr 805-806.

reduce the balance associated with the ICC (regulatory asset/liability).[307] And he stated, since the Company is not currently requesting a surcharge for the incremental cost of compliance, there is no need to contemplate an increase in the costs recovered through the PSCR at this time.[308]

He concurred with Mr. Jester that adoption of his transfer price method would result in a curtailed or eliminated regulatory asset in the near term and emphasized that it may be premature to adjust the transfer price at this time as it would indeed create an unnecessary extra accounting process in the future.[309] Mr. Harlow asserted that there are other methods that might be used to establish a transfer price proxy, such as the LCOE of solar, but the current method is still valid.[310] If the Commission thinks it is appropriate to reevaluate the Staff transfer price methodology, he recommended that it be done in a workgroup.[311]

Staff witness Revere disagreed with ABATE's proposal that, if the current method of determining the split between energy and demand portions of the transfer price is changed, the proportion of demand-related costs be maintained. He explained that maintaining the current proportional split would be more appropriate.[312] He also disagreed partially with GLREA's assertion that the transfer price be based on the cost of building renewable generation, as such generation is now the lowest-cost option. He explained:

> [T]he transfer price was intended to separate the additional cost of renewable over traditional generation and treat the cost that would be associated with the generation were it not renewable the same way as

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[307] 4 Tr 806.
[308] 4 Tr 806.
[309] 4 Tr 806-807.
[310] 4 Tr 807.
[311] 4 Tr 807-808.
[312] 4 Tr 880.

> traditional generation costs. With regard to PPAs, to the extent that the transfer price is higher than the cost of renewables, customers do not pay more for the renewables than they cost through the transfer price. Instead, the amount of cost included in the PSCR through the transfer price is the actual cost if lower than the transfer price. For Company-owned generation, the Company is currently (and temporarily) allowed to include through the transfer price the higher of the transfer price or the levelized cost of the facility. However, this does not result in higher costs being borne by customers as any "overpayment" through the transfer price is recorded to the regulatory liability under the REP and accrues to the benefit of customers, rendering the impact on them neutral over time.[313]

He recommended that the Commission reject GLREA's proposals.[314]

In briefing, Staff remarks that it understands that there is a pending transfer price conference agreed to the settlement in Case No. 21662 and that by the time of the reconciliation case pertinent to this matter, the transfer price issue may be decided.[315]

In briefing, MEC-NRDC counters Staff's contentions that it would be premature to modify the transfer price or that the current proxy of a traditional NGCC is still appropriate.[316] Among other things, MEC-NRCD argues that Staff has been on record for 13 years stating that the transfer price should be based on what a Michigan electric provider would pay in a long-term PPA, and in Case No. U-21662 Mr. Harlow testified that is unlikely that a Michigan electric provider would enter into a long-term PPA for a gas plant without carbon capture and storage (CCS), so there is no evidentiary basis on which to continue basing the transfer price on a proxy gas plant without CCS.[317]

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[313] 4 Tr 881-882.
[314] 4 Tr 882.
[315] Staff initial brief, pp. 5-6.
[316] MEC-NRDC initial brief pp. 62-67; MEC-NRDC reply brief, pp.8-10.
[317] MEC-NRDC initial brief p. 64.

MEC-NRDC states that for the Commission to approve Consumers' transfer price schedules, there must be substantial evidence to support it.[318] MEC-NRDC maintains that there is no evidence in this record that a gas plant without CCS remains a reasonable market proxy for setting the transfer price and the Commission cannot approve a transfer price schedule that is not based on substantial evidence on the rationale that changing the transfer price methodology will not affect surcharges this year.[319] MEC-NRDC closely reviews ABATE's arguments against revising the transfer price, and opines that they are useless and lack merit.[320]

Similarly to Staff, MEC-NRDC notes that the Commission has directed Staff to convene a symposium on transfer prices as part of the U-21662 settlement and that workgroup has met, and Staff will be issuing a report later this summer.[321] MEC-NRDC argues that the Commission should not approve Consumers' transfer price schedule in the meantime as there is no substantial evidence to support it and transfer prices are approved in the reconciliation case – not the plan.[322]

ABATE responds, stating among other things, that there is "no evidentiary basis on which to assume the transfer price should be based on a proxy gas plant at all, CCS-equipped or otherwise" and there are "a number of different resources which may serve as reasonable proxies for the transfer price, not to mention the myriad factors for determining the transfer price set out in MCL 460.1047(2)(b)(iv)," such that exploring the

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[318] Id at pp. 66-67 citing *In re Application of Indiana Michigan Power Co* 307 Mich App 272, 296 (2014) and *ABATE v MPSC (In re Detroit Edison Co)*, 296 Mich App 101, 115 (2012).
[319] Id at p. 67.
[320] MEC-NRDC initial brief, pp. 68-72; MEC-NRDC reply brief, pp. 10-14.
[321] MEC-NRDC reply brief, p. 10.
[322] Id.

options should be done in the symposium established in Case No. U-21662.[323] ABATE asserts that MEC-NRDC's request is based on speculation, there is inadequate evidence to support it, and it should be left to the symposium ordered in Case No. U-21662.[324]

This PFD finds that the current transfer price method likely needs to be modified, as recommended by MEC-NRDC and by GLREA. MEC-NRDC's arguments that the transfer price calculation must replace the traditional NGCC proxy with an NGCC with CCS proxy are well taken considering Act 235's requirements for a clean energy portfolio of 80% by 2035 and 100% by 2040 and EPA's rule requiring new gas plants to operate with 90% effective CCS by 2032. However, as noted by Staff, all potential proxies should be explored, such as the use of a solar facility, which MEC-NRDC found reasonable. As several of the parties noted, a workgroup including all rate-regulated utilities and interested parties would be the best vehicle to determine this contentious issue and accordingly the Commission ordered a symposium on transfer prices in Case No. U-21662.

This PFD disagrees with MEC-NRDC that the Commission should reject Consumers' transfer price schedule in the meantime because MEC-NRDC contends there is no substantial evidence to support it and transfer prices are approved in the reconciliation case. Staff's support of Consumers proposals is persuasive and the Company's indication that the use of the new schedules causes an insignificant impact on the total cost transferred to PSCR via the transfer price is also supportive of the new schedules. This PFD finds that there is sufficient evidence on the record in this case to

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[323] ABATE reply brief, pp.3-11.
[324] Id at p. 11.

approve the Company's request until the appropriate proxy for the transfer price can be determined via the symposium. This PFD declines to adopt MEC-NRDC witness Jester's specific recommendation to adopt an incremental addition to the Company's proposed transfer prices that is equal to the cost of compliance as estimated by the EPA as this issue should also be addressed in the symposium. The PFD therefore does not consider Mr. Jester's subsequent recommendation to direct the Company to provide for an earlier disbursement to customers of the projected regulatory liability in its next REP. This PFD agrees with ABATE that any changes to the transfer price method be done thoughtfully and carefully with transparency. But this PFD disagrees with ABATE's proposal that if the current method of determining the split between energy and demand portions of the transfer price is changed, that the proportion of demand-related costs be maintained, agreeing with Staff that maintaining the current proportional split would be more appropriate.

Based on the foregoing, this PFD recommends that the Commission continue the current transfer price methodology and regulatory liability balance for Company-owned assets in the REP through December 2045 and approve Consumers' simplified transfer price schedules to replace those approved Case No. U-15805 and Case No. U-16581.[325] This PFD also recommends that the Commission direct that the symposium ordered in Case No. U-21662 be continued to ensure it addresses and determines the appropriate proxy for the transfer price going forward and whether any modifications to the transfer

[325] Id.

price causes changes to the regulatory asset/liability that necessitates changes to the disbursement schedule of the projected final regulatory liability.

E. Incremental Cost of Compliance

Included in the Company's amended REP is the projected incremental cost of compliance (ICC) with the renewable energy standards for a 20-year period, as set forth in Exhibit A-4 and discussed by Mr. Bleckman. Mr. Bleckman explained that the calculation of the ICC for this case used the same method as was used in the Company's 2023 REP amendment, Case No. U-21374, with the addition of the financial compensation mechanism (FCM) authorized under MCL 460.1047(2)(a)(v)(C).[326]

Mr. Bleckman described how costs are calculated in line 2 of Exhibit A-4, noting that costs include all projected financing and capital costs (including a return on equity (ROE)), depreciation expense, general taxes, and O&M expenses associated with the Company's investment in new renewable energy systems.[327] Mr. Bleckman noted that projected capital expenditures, PPA expense, and O&M expense in this REP are based on costs for previously approved projects that are in commercial operation.[328] In line 9 of Exhibit A-4, Mr. Bleckman included offsets for federal tax credits, which the Company expects to receive over the plan period.[329]

Mr. Rafson testified that no federal tax credits or incentives should be assumed for projects that reach commercial operation beyond 2032, explaining that:

> The [federal tax] incentives at most will continue through the [infrastructure recovery act] IRA incentive period which tails off to zero starting in 2032. Thus, no more than 7 years of federal tax incentives should be considered.

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[326] 2 Tr 176.
[327] 2 Tr 176.
[328] 2 Tr 178-179, 182-183.
[329] 2 Tr 184.

> It is our opinion that the company's assumed tax credits in the REP of approximately $8.9 billion are both extremely high and fail to show the impact of the REP on customers. The calculations like the LCOE is low by the amount of the tax credits assumed. If these incentives are not received the result would likely greatly increase the cost recovery and result in much higher customer rates.[330]

In rebuttal, Mr. Bleckman explained that "the IRA establishes a phase out for the credits, by 25% annually from 100% to 0% in the latter of 2032 or the year in which Treasury determines that annual greenhouse gas emissions [GHG] from the production of electricity in the US are equal to or less than 25% of the annual greenhouse gas emissions for 2022."[331] Mr. Bleckman testified that he is unaware of any forecasted data predicting the date when annual GHG emissions will be equal or less than GHG emissions for 2022, adding that the federal government has a history of extending sunset provisions. Consistent with his testimony, Mr. Bleckman stated that it is reasonable to assume that incentives for renewables will continue beyond 2032.[332]

GLREA's briefing does not address this issue directly, but it does raise concerns about the ending of federal incentives for renewables in the context of LCOE. Consumers maintains that its ICC calculation does not need to be modified at this time.[333]

This PFD agrees with Consumers that, based on the information available when this case was filed, Consumers inclusion of federal tax incentives after 2032 was reasonable. If circumstances change, the Company may update its ICC calculation in the future.

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[330] 4 Tr 624-625.
[331] 2 Tr 197.
[332] 2 Tr 197-198.
[333] Consumers initial brief, 35-36.

F. Revenue Recovery Mechanism

Mr. Johnston testified that Consumers is not proposing to implement a revenue recovery mechanism (i.e., renewable energy surcharge) to recover its ICC in this proceeding. According to him:

> While the Company's filing reflects that the Company will experience incremental costs of compliance on an annual basis through 2034, the incremental costs of compliance turned decidedly negative in 2035 through 2041, resulting in a projected regulatory liability at the end of the 20-year RE Plan period. As such, a levelized revenue recovery mechanism, as provided for in MCL 460.1045(3), for the 20-year period is unnecessary.[334]

Mr. Johnston added that there are additional reasons to forgo a revenue recovery mechanism, including; (1) it would essentially pre-pay for Company-owned resources that would benefit future customers, which in turn would likely lead to a credit for future customers rather than the customers who prepaid; and (2) based on cost-of-service principles, it may occur that Consumers acquires more renewables than called for in its plan, thus leading to a lower ICC, and a greater need to avoid a revenue recovery mechanism.[335]

Turning to the potential for a large regulatory liability at the end of the 20-year plan period, Mr. Johnston testified that if a large balance exists after 2037 the Company will take measures to adjust revenues to reduce the balance. In any event, Mr. Johnston stated that the Company will address and adjust the balance in future REP amendments.[336]

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[334] 2 Tr 58.
[335] *Id.*
[336] 2 Tr 59.

Mr. Jester noted that per Exhibit A-5, Consumers has a current regulatory liability balance of $49.9 million, which, according to Mr. Bleckman will turn into a regulatory asset until 2034, then returning to a projected regulatory liability balance of $332.7 million in 2045.[337] With respect to the Company's proposal for managing its deferred accounting, Mr. Jester stated:

> In general, I support Consumers Energy's intent to avoid applying surcharges to avoid accumulation of a regulatory asset when they anticipate subsequent development of a regulatory liability. However, in the event that the Commission accepts my recommendations concerning transfer prices, a build-up of regulatory asset will be greatly curtailed or eliminated and Consumers Energy's projected regulatory liability circa 2045 will be substantially larger. In that event, I recommend that the Commission direct the Company to either eliminate the use of a regulatory liability or to early create an appropriate sur-credit to disburse the projected regulatory liability by 2045. This analysis should be done in Consumers Energy's next amendment of its REP.[338]

In its brief, Consumers reiterates that it intends to manage its regulatory liability balance as necessary to minimize that balance, noting that the regular filings of REPs will allow it to do so.[339] MEC-NRDC's brief does not squarely address this issue.

This PFD agrees with Consumers that regular REP filings will allow for sufficient scrutiny and adjustment of any regulatory asset or liability occurring over the plan period. As noted above, this PFD recommends that the changes proposed by MEC-NRDC to the transfer price be rejected for now. As such, Mr. Jester's concerns regarding the future regulatory liability are moot.

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[337] 2 Tr 408.
[338] 2 Tr 409.
[339] Consumers initial brief, 37-38.

G. Voluntary Green Pricing Program

Consumers points to the August 22, 2024 order in Case No. U-21374, the Company's last amended REP, wherein, *inter alia*, the Commission removed the 1,000 MW cap on the addition of new facilities, provided that 75% of the expected energy production is subscribed before assets are added to the VGP program. Consumers is proposing to build, own, and operate approximately 1.1 GW of VGP solar, 731 MW of which are identified, including: (1) Sunfish II Solar (309 MW); (2) Karn Solar Energy (85 MW); and (3) two proxy solar projects with expected in-service dates in 2028 totaling 337 MW.[340]

Mr. Rafson raised a concern about the "non-industrial" portion of the VGP program, testifying that "the obligation of not building new energy resources until subscriptions total at least 75% of expected energy production will create an unreasonable burden on residential and small commercial customers to clear this fence. This program essentially makes the VGP for residential/commercial customers a very different program compared to that of industrial customers."[341]

In addition, for the "industrial" portion of the VGP, Mr. Rafson posited that "[this] program improperly provides for the building of renewable energy assets specifically for industrial customers. Presently, between the Economic development tariff and VGP, nearly ½ of industrial clients have effectively opted out of Consumers legacy generation pool leaving the commercial and residential customers to pay for these more expensive

[340] Consumers initial brief, 41-42.
[341] 4 Tr 615.

generation costs."[342] He added that "industrial" VGP affects non-subscribers because non-subscribing customers must pay for more costly legacy generating assets.[343]

In response, Mr. Johnston pointed out that the 75% subscription requirement was established in the December 9, 2021 order in Case No. U-20984, which approved a settlement agreement. According to him, "[t]he intent of the subscription limit was to ensure that VGP asset additions did not outpace subscriptions to minimize the cost impact on PSCR customers."[344] In rebuttal to Mr. Rafson's claims about the "industrial" VGP program and purported cost shifts to non-participating customers and inequities between program offerings for residential versus industrial subscribers, Mr. Johnston explained that "[i]t is incorrect to state that the Renewable Energy Program for any customer class offers them an advantage in price. Only the Company's Pilot Solar Gardens Program and Renewable Energy Credit Program, which are separate and distinct from the Renewable Energy Program, have different pricing."[345] He added that the REP program (formerly the LC-REP) is comprised of a pool of renewable assets that a customer of any class (residential, commercial, or industrial) may subscribe to for the same price.[346]

GLREA's brief did not address this issue, and the Company's brief relies on Mr. Johnston's testimony.

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[342] 4 Tr 616.
[343] *Id.*
[344] 2 Tr 108.
[345] 2 Tr 109. It should be noted that in the August 22, 2024 order in Case No. U-21374, pp. 9-12, the Commission approved Consumers' proposal to rename the LC-REP, previously open only to large industrial customers, to the Renewable Energy Program, open to all electric customers in good standing. As quoted above, the Solar Gardens and Renewable Energy Credit Programs are separate VGP offerings.
[346] 2 Tr 108-109.

This PFD finds that GLREA's concerns regarding the structure of the REP VGP program are misplaced, as discussed in Consumers' brief at 42-43. It bears emphasizing that pursuant to MCL 460.1061, VGP programs are optional and VGP customers are required to pay all costs for the program, such that non-participating customers are not subsidizing VGP customers.

Mr. Bleckman also testified that Consumers plans to expand its existing Solar Gardens Community Solar program by adding 2.5 MW of capacity in 2026 and an additional 3.0 MW in 2030, for a total of 5.5 MW.[347] According to him, costs for the Solar Gardens were based on a proxy facility with a net capacity factor of 24% and capital costs of $15 million.

Mr. Rafson testified that the Solar Gardens program should not be expanded positing that the program is a "far worse deal" for residential customers than the Company's offerings for industrial customers, pointing to the high LCOE for the proposed new facilities.

In rebuttal, Mr. Johnston disagreed, noting that the Company is not actually "expanding" the Solar Gardens program, which is limited to 10 MW. According to him, Consumers currently has 4.5 MW of assets in the program (of which, 99.5% are subscribed) and proposes to increase solar capacity up to the 10 MW cap by 2030. Mr. Johnston reiterated that the Solar Gardens Community Solar program is voluntary, and residential customers can subscribe to the REP if cost is a consideration.[348] In addition, Mr. Johnston explained that the Commission has reviewed and approved the LCOE for

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[347] 2 Tr 181.
[348] 2 Tr 116-117.

Solar Gardens in Case No. U-21374, and the Company is moving forward on a new Solar Gardens facility and has requested approval in an application filed on March 14, 2025 in Case No. U-15805.[349]

GLREA summarized Mr. Rafson's testimony in its initial brief but did not address Mr. Johnston's rebuttal. Consumers relied on Mr. Johnston's testimony in its brief.[350]

As was the case with the REP VGP concerns discussed above, GLREA appears to have a basic misunderstanding of how the Company's VGP programs for residential customers currently operate. As such, this PFD finds that GLREA's general concerns with the structure of the Solar Gardens program should be dismissed.

1. VGP Credits

As set forth in Consumers' brief, GLREA witness Richter recommended that the Commission direct Consumers to change its VGP credit calculation in various ways, as a means to encourage more participation in the program.[351] Mr. Johnston and Staff witnesses Heidemann and Revere presented extensive rebuttal to GLREA's proposals. In its initial brief, GLREA states:

> GLREA witness Richter made two specific recommendations for changes to the credits paid to VGP participant customers. However, there was well-founded rebuttal in response. We still believe that the current charge and credit structure fails to reflect the cost and benefits of the program. However, we offer an alternative proposal. We would like the opportunity to meet with stakeholders and see if any common ground can be found. Recognizing that such a price restructuring should be done consistently across all affected utilities, we request that the Commission order the creation of a workgroup on VGP charges and credits, as we did in the concurrent DTE VGP case (U-21375).[352]

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[349] 2 Tr 117.
[350] GLREA initial brief, 23; Consumers initial brief, 43-44.
[351] Consumers initial brief, 44 citing 4 Tr 581-588.
[352] GLREA initial brief, 17.

In its reply brief, Consumers argues that GLREA's request for a workgroup is unnecessary because the Company will be filing its next VGP case in the fall of 2025, and issues or modifications concerning program design and credits may be addressed as part of that proceeding.[353]

This PFD agrees with Consumers that issues concerning VGP programs, charges, and credits are not appropriate for inclusion here and should be addressed in the Company's next VGP review. Further, this PFD agrees with Consumers that programmatic and pricing provisions for VGP programs are "unique to that electric provider and should be addressed in their own dedicated VGP proceedings" and not as part of a workgroup process.[354]

2. Community Solar

Mr. Rafson testified that the amended REP is deficient is because it fails to adequately address community solar, which, "if done like Maine or Minnesota, could represent 800-1,000 MW of solar generation and therefore be a significant contribution to achieving the RPS at little or no cost to the company" and result in lower cost than the amended REP.[355] Mr. Rafson also made proposals regarding compensation for community solar subscribers and inclusion of community solar RECs as part of the Company's compliance with the RPS.[356]

While several witnesses responded to Mr. Rafson's proposals, this PFD agrees with Consumers' overarching argument that specific issues concerning VGP and

[353] Consumers reply, 9.
[354] Consumers initial brief, 44.
[355] 4 Tr 614.
[356] 4 Tr 621-622.

community solar programming, cost, and credit structures should be addressed as part of Consumers next VGP filing later in 2025. The parties may choose to present the same evidence and arguments in that proceeding, which is focused solely on VGP programming, including community solar.

H. Co-located Energy Storage

The parties took issue with several of the Company's proposals in connection with renewable energy storage resource additions, which will be addressed in more detail below.

1. Ownership of Energy Storage Resources

Mr. McDonnell again recommended a competitive procurement process for energy storage resources requiring: use of an IA to oversee bidding; a 50/50 ownership split between third-party and Company-owned resources; and a process to update the Company's LCOE target to reflect prevailing market conditions, including revisiting whether LCOE is the best metric for establishing an energy storage cost threshold.[357] While recognizing the value of energy storage to the grid, he expressed concern that the amendments proposed by the Company regarding co-located storage risked exposing ratepayers to unnecessary costs.[358] Specifically, Mr. McDonnell testified that "the Company's focus on co-locating storage additions only with Company-owned renewable assets is unnecessarily restrictive and may preclude opportunities for savings from a broader competitive procurement of energy storage resources."[359]

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[357] 4 Tr 638.
[358] 4 Tr 663.
[359] 4 Tr 663-664.

Mr. McDonnell noted Consumers' expressed intention to pursue energy storage projects only if they shared a point of interconnection with the renewable energy system, and only if they were Company-owned.[360] He disputed the Company's assertion that coordination with third-party owned renewable facilities would be difficult or impossible to effectively manage.[361] He took the position that coordination would not be an issue if both the renewable and energy storage facility were owned by the same third party, adding that any issues caused by the Company not having direct control over the energy storage facility could be addressed through contract terms, citing the Century Oaks Energy Storage LLC tolling agreement as an example.[362]

Mr. McDonnell also contended that energy storage additions should not be limited to surplus energy storage and the Company should "pursue other energy storage options that may be more cost-competitive or advantageous for other reasons."[363] He pointed out that the retirement of the Karn and Campbell Units provide an opportunity for resources to be interconnected using the generator replacement process, which also allows for faster interconnection and lower costs. Therefore, while noting that integration of energy storage is best evaluated through the IRP process, Mr. McDonnell recommended that deployment of energy storage resources through the amended REP should include opportunities for both Company ownership and third-party ownership.[364] He

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[360] 4 Tr 664.
[361] 4 Tr 664-665.
[362] 4 Tr 665.
[363] 4 Tr 667.
[364] 4 Tr 667.

recommended that the Commission "direct the Company to make all commercially reasonable efforts to follow a 50/50 ownership split."[365]

In rebuttal, Mr. Johnston noted that the Company has already contracted for 400 MW of battery energy storage systems (BESS) with third parties, indicating that the Company will consider hybrid projects as part of its independent auditor-led solicitations, adding that the Company was "willing to contract for or own BESS depending on the economics."[366] However, Mr. Johnston clarified that, for co-located sites, the Company would either own both the renewable energy resource and BESS, or would contract to control both. To do otherwise would be ineffective and "limit the Company's ability to select lowest cost renewable energy wind resources."[367]

Mr. Clark, in his rebuttal, also disagreed with Mr. McDonnell's recommendations, noting that the Company already allows for competitive bidding for REP contracts.[368] He added that an IA is unnecessary, and would only add needless expense, because the Company does not perform construction activities with its direct workforce, or manufacture BESS components, so the Company is not in direct competition with bidders.[369] The Company also disagreed with the proposed 50/50 split for ownership of energy storage because all of the proposed energy storage is co-located, hybrid or surplus energy storage installed at existing, Company-owned interconnections. Mr. Clark articulated the Company's understanding that MISO rules only permit surplus interconnection agreements with the primary interconnection customer, and that surplus

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365 4 Tr 665-667, 674.
366 2 Tr 89.
367 2 Tr 89-90.
368 2 Tr 233.
369 2 Tr 233-234.

interconnections are forfeited when an interconnection agreement is terminated, making it infeasible for third parties to own and operate such BESS facilities.[370]

Mr. Harlow testified in his rebuttal that Staff was supportive of including options for "third-party PPAs in each renewable energy and energy storage solicitation going forward," but reiterated that Staff did not support a mandated 50/50 ownership split.[371] Staff took the position that the most cost-effect resources should be selected regardless of ownership.[372] Staff's brief does not directly address 50/50 ownership of storage, but Staff repeats the position that, while 50/50 ownership should be encouraged, it is reasonable for the Company to select resources based on lowest cost.[373]

MEIU cites Mr. McDonnell's testimony for the proposition that, if the Commission permits the Company to include energy storage assets in its amended REP, this should include requirements for 50/50 ownership between Consumers and third parties, as well as IA administered bid solicitation and revisiting LCOE as the appropriate metric for measuring ex parte cost caps.[374] MEIU notes Mr. Clark's testimony regarding the five types of BESS: standalone, replacement, surplus, hybrid, and co-located, and Mr. Clark's testimony supporting Consumers' request to include in its amended REP up to 1,100 MW (830 MW wind and 250 MW solar) of co-located, hybrid, and surplus BESS, cited at Company-owned renewable energy installations.[375] MEIU also notes that Mr. Clark proposes a "similar 140% of LCOE ex parte approval cap for this storage, which would

[370] 2 Tr 234.
[371] 4 Tr 809.
[372] 4 Tr 809-810.
[373] Staff initial brief, 14.
[374] MEIU initial brief, 18-24.
[375] MEIU initial brief, 19.

allow the Company to seek ex parte approval" if "an energy storage project's LCOE falls below $200.96/MWh."[376]

MEIU advances Mr. McDonnell's concern that the Company proposes only Company-owned co-located storage, which is unnecessarily restrictive and may preclude savings from broader competition; this concern is exacerbated by the proposed LCOE cap.[377]

Consumers contends that Mr. McDonnell's recommendations should be rejected because the company already uses a competitive bidding process and IA is not required or necessary for engineering, procurement, or construction (EPC) services for energy storage resources. Consumers also does not manufacture energy storage components or perform construction activities, so adding an IA to the solicitation process, where the Company is not comparing its own products and services to a third party, would add needless expense. [378] Consumers reiterates that, while it is willing to contract with third parties for energy storage projects outside of the RE plan if the conditions are favorable, inclusion of such energy projects in the RE plan is inappropriate because the proposed energy storage is co-located, hybrid, or surplus energy storage installed at Company-owned existing interconnections.[379]

Consumers clarifies that third-party interconnection customers could not interconnect under Consumers' MISO interconnection agreement. As a result, it would not be feasible for third parties to own and operate battery storage facilities that rely on

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[376] MEIU initial brief, 19.
[377] MEIU initial brief, 19-20.
[378] Consumers initial brief, 49.
[379] Consumers initial brief, 49.

Company-owned interconnections because surplus interconnection agreements are only available to the primary interconnection agreement customer.[380] Consumers takes the position that the Commission has no authority to require third-party ownership of energy storage facilities, and that such a requirement would be "ineffective to manage and could increase costs."[381]

In its reply brief, MEIU suggests that Consumers is ignoring the possibility of "third-party-owned storage co-located with existing third-party-owned renewable energy facilities," and otherwise repeats its recommendations.[382] Consumers' reply relies upon pages 49 and 50 of its initial brief in requesting that MEIU's recommendations be denied. Consumers clarifies that it will already be considering hybrid storage projects, and it contends that the Company should be permitted to select the lowest cost resource without the imposition of a 50/50 ownership split. The Company encourages the Commission to reject requirements to use something other than LCOE to compare energy storage projects.[383]

For reasons already discussed, this PFD recommends rejection of a 50/50 ownership requirement, or any of MEIU's other recommendations, should the Commission include co-located storage as a renewable resource in this REP.

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[380] Consumers initial brief, 49-50.
[381] Consumers initial brief, 50.
[382] MEIU reply, 5-6.
[383] Consumers reply, 9-10.

2. Energy Storage Cost Recovery

Mr. Clark testified that energy storage supports the Company's plan to meet its RPS targets and the Company proposes to recover all costs of energy storage projects in the amended REP through the REP cost of compliance.[384]

Mr. Harlow testified that Staff has three concerns about the company's cost recovery proposal for the fixed costs of co-located storage: (1) storage is not listed as a renewable energy resource under MCL 460.1011(g); (2) historically only renewable energy resources are included in the renewable energy cost recovery mechanism in the Act; and MCL1022(3) clearly defines that the amended REP includes a forecast of *renewable energy resources* that are needed to comply with the RPS.[385]

Mr. Harlow explained that while Act 235 establishes a statewide energy storage target and provides incentive credits for renewable energy generated off-peak and stored using an energy storage system, it does not include energy storage under the definition of "renewable energy resource" under MCL 460.1011(g).[386] As for cost recovery of energy storage under the Act, Mr. Harlow points to MCL 460.1101(4), which states that for approved eligible storage contracts, the utility may seek to "recover the costs of the contract in the electric provider's base rates."[387] Because of this Staff submits that storage assets should be recovered in base rates through a general rate case.[388]

Mr. Harlow stated that Staff's opinion does not change even if the energy storage is co-located with the renewable resource. He testified that "tying cost recovery of a co-

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[384] 2 Tr 217-218.
[385] 4 Tr 792-793.
[386] 4 Tr 793.
[387] Id.
[388] 4 Tr 794.

located storage facility to that of the traditionally defined renewable energy resource it is co-located with could result in inefficient operation of that storage asset.[389] He explained that:

> If the storage asset where to be connected to the Direct Current (DC) side of the renewable asset point of interconnection (POI) and only charge from the renewable energy resource that it is co-located with in an effort to effectively call it a single resource for purposes of cost recovery, as opposed to charging directly from the distribution or transmission grid, it would mean that charging would be limited to the intermittent generation of the renewable energy system. Regardless of whether the storage is on the DC side or connected to the Alternating Current (AC) side of the renewable asset POI, the Company can still allocate costs to each of the assets even if they share components within the common POI.[390]

Based on the foregoing, Staff recommends that the Company install storage assets in a manner that allows it to optimize charging using both the shared interconnected asset and/or the grid itself, noting that absent this configuration, the value of storage to the broader grid is diminished.[391]

Mr. Johnston countered that the REP should include the cost recovery of energy storage pursuant to MCL 460.1047(2)(a)(vii), which states that "[a]ny additional electric provider costs determined by the commission to be necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards.[392] He posited that this means energy storage costs can be recovered under the REP.

As for the efficient operation of energy storage, Mr. Clark posited that because energy storage will not see a material impact in operation and will only have limitations

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[389] Id.
[390] Id.
[391] 4 Tr 794-795.
[392] 2 Tr 91.

during full output of the traditional renewable resource it would not affect the efficiency of the energy storage.[393] He explained that under normal operations, an energy storage asset is typically designed to discharge over 4 hours and charge over the same period, which would allow, under normal operations, the energy storage asset to charge and discharge once a day without impact to a solar asset and only minor impact from full production of a wind asset.[394] He testified that the Company's energy storage assets are optimized to best utilize the interconnection facilities and to best utilize the traditional renewable energy asset by optimizing the sizing of the energy storage to maximize energy, capacity, and renewable energy credit values for a given project.[395] He asserted that through this optimization, the energy storage asset will act as an enabler of renewable energy and improve the functionality of the traditional renewable generation asset and will not hinder the efficiency of the energy storage facility.[396]

In briefing, Consumers argues that an energy storage system charged from a renewable resource falls within the definition of "renewable energy system" in subsection 11(i) in the Act because it is a facility that uses "1 or more renewable resources to generate electricity or steam."[397] The Company adds that the renewable energy resource will be used to charge the energy storage system, which will have the benefit of reducing curtailment of the renewable energy resource and improving the total energy output from the renewable energy resource, resulting in increased RECs.[398] Additionally, Consumers

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393 2 Tr 228.
394 Id.
395 Id.
396 2 Tr 228-229.
397 Consumers initial brief, p. 46.
398 Id.

states, the energy storage system is using the associated renewable energy resource to inject that generated renewable energy into the transmission or distribution system.[399] Consumers illustrates by explaining that whether energy from a solar facility, for example, is being provided to the grid directly from the solar facility or from the energy storage system that has been charged from the solar facility, the energy is being generated from "solar and solar thermal energy," which are renewable energy resources under MCL 460.1011(g)(ii).[400] And further, states the Company, energy storage resources are not listed as one of the exclusions from the definition of "renewable energy system" under MCL 460.1011(j).

As for MCL 460.1101(4), Consumers argues that it does not prohibit recovery of co-located energy storage resource costs through the REP.[401] The Company asserts that considering the entire section, i.e., MCL 460.1101, indicates that that subsection 4 refers to contracts that are meant to support the statewide storage target and does not prevent the recovery of co-located energy storage resources that support RPS compliance in the REP.[402]

In its brief, Staff states that, "if the legislative intent was to consider energy storage resources as renewable and/or consider cost recover [sic] of these assets under the cost recovery mechanisms at Section 47 (MCL 460.1047) and Section 49 (MCL 460.1049)… the Legislature would have clearly included energy storage resources in the definition of "renewable energy resources".[403]

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[399] Id at pp. 46-47.
[400] Id at p. 47.
[401] Id.
[402] Id at pp.47-48.
[403] Staff initial brief, p. 3.

Staff is also not convinced that co-located energy storage increases the quality and reliability of renewable energy, such that its costs could be recovered under the REP through MCL 460.1047(2)(a)(vii). Staff states that co-located energy storage simply allows the renewable energy to be stored when not needed on the grid. Staff explains that renewables are always contributing to the grid as they tend to be "must run assets" therefore if storage is being optimally used, it is most likely using non-co-located grid energy to charge at low load times and specifically not that of the renewable asset that it is electrically nearby, unless it is connected to the renewable resource behind the meter.[404] Staff avers that DC coupled storage with renewable energy would not allow the storage to be optimally utilized to provide benefit to the grid as a whole and thus, recovery of co-located storage should not be approved in the REP, it should be approved in base rates.[405]

This PFD agrees with Staff that energy storage costs, including co-located energy storage costs, should be recovered in base rates. Act 235 speaks directly to the issue of cost recovery of energy storage at MCL 460.1101(4).[406] The statute uses the word "shall" and therefore indicates a mandatory directive.[407] The language of MCL 460.1101(4) is clear and unambiguous and reflects the Legislature's intent that energy storage costs

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[404] Id at p. 4.
[405] Id.
[406] That statute states in pertinent part: "An electric provider whose rates are regulated by the commission shall submit to the commission for review and approval eligible energy storage contracts entered into to meet its share of the statewide storage target under subsection (1). If the commission approves an eligible energy storage contract, the commission shall authorize the electric provider to recover the costs of the contract in the electric provider's base rates." MCL 460.1101(4) (emphasis added). The statute also defines an "eligible energy storage contract" as "a contract to construct, acquire, or use the services of an eligible energy storage system." MCL 460.1101(9)(a).
[407] *People v Lockridge*, 498 Mich 358, 387, 870 NW2d 502, 518 (2015).

should be recovered in base rates.[408] Consumers' arguments that subsection 4 only refers to contracts for energy storage that are used to meet Act 235's energy storage goals are unavailing.

This PFD disagrees with Consumers argument that co-located energy storage uses one or more renewable energy resources to generate electricity or steam and hence it meets the definition of a "renewable energy system at MCL 460.1011(i)."[409] Energy storage does not generate electricity, rather it is a technology that absorbs, stores, and releases energy.[410] The Company's point that energy storage resources are not listed as one of the exclusions from the definition of "renewable energy system" under MCL 460.1011(j) is dispatched under the doctrine *Inclusio Unius Est Exclusio Alterius:* since co-located energy storage is not mentioned in the list of exclusions, it is implied that the Legislature did not intend to exclude it. This PFD also does not agree that cost recovery of co-located storage through the REP is permissible under MCL 460.1047.[411] Co-located energy storage is an optional cost, it is not "necessarily incurred" to ensure the quality and reliability of renewable energy used to meet the RPS.

As to Staff's recommendation that the Company install storage assets in a manner that allows it to optimize charging using both the shared interconnected asset and/or the

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[408] See *City of Grand Rapids v Brookstone Cap, LLC*, 334 Mich App 452, 459; 965 NW2d 232 (2020) ("When courts interpret statutes, they must first look to the specific statutory language to determine the intent of the Legislature, and if the language is clear and unambiguous, the plain meaning of the statute reflects the legislative intent and judicial construction is not permitted.").
[409] DTE brief, 55.
[410] *See* MCL 460.1005(i) and MCL 460.1221(j); *see also* MCL 460.1039(2)(c), which provides that a renewable energy system generates electricity, and an energy storage system stores it.
[411] That statute states in pertinent part that the ICOC can include, among other things, "Ancillary service costs determined by the commission to be necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards, regardless of the ownership of a renewable energy system." MCL 460.1047(2)(a)(iv).

grid itself, this PFD finds such a directive unnecessary at this time since the Company asserts that its energy storage assets are optimized to maximize energy and capacity. While the Company also states that it optimizes its energy storage to maximize renewable energy credit values for a given project, it is unclear how this would impact the efficiency of the storage asset. Therefore, this PFD declines to adopt Staff's recommendation regarding the manner of installation of the storage asset. As stated above, however, this PFD recommends disapproval of the Company's proposal to recover the fixed costs of energy storage, including co-located energy storage, through the REP cost of compliance, finding that they must be recovered in base rates.

I. Financial Compensation Mechanism

Consumers states that MCL 460.1028(8) provides that the Commission shall authorize an annual financial incentive for a utility that enters into PPAs for renewable energy resources or a third-party contract for an energy storage system or clean energy system for any contract entered into after June 30, 2024.[412] Consumers states that its Amended REP includes a FCM for contracted renewable energy resources, with the FCM being calculated using the pre-tax weighted average cost of permanent capital to annual contract payments, as set forth in MCL 460.1028(8).[413] Consumers states that recovery of FCM costs related to eligible contracts will be included in Consumers' PSCR mechanism.[414] Consumers asserts that it will allocate the FCM in the same manner that the underlying purchased power contract costs are allocated to energy and capacity.[415]

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[412] Consumers initial brief, p. 50.
[413] Consumers initial brief, p. 51.
[414] Id., citing 2 Tr 48.
[415] Id., citing 2 Tr 81.

The Attorney General states that the FCM was originally proposed by Consumers in its 2018 IRP proceeding (Case No. U-20165) as a means to address a perceived incentive problem associated with purchase power agreement ("PPA") structures.[416]

Mr. Deupree states that the Commission's order in Consumers' 2021 IRP (Case U-21090) approved a settlement wherein the parties agreed to the following FCM restrictions: the FCM was extended at the after-tax WACC of 5.62% subject to updates in electric rate case orders; the FCM was approved for all new PPA's but did not apply to PPA amendments, PURPA PPA's, and Voluntary Green Pricing PPA's, or any PPA's executed under the REP; and the FCM was subject to price caps.[417]

Mr. Deupree recommends that the Commission direct Consumers to not include an FCM for any new PPA contract attached to future renewable energy projects required to meet its VGP and REP requirements.[418] The Attorney General argues that Consumers' requested FCM on REP PPAs would represent a redundancy, adding needless costs for recovery and shifting risks to ratepayers.[419]

The Attorney General argues that that the enactment of PA 235 did not abrogate Consumer's responsibilities under its 2021 IRP settlement.[420] Noting that pursuant to its settlement Consumers agreed that it "shall not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan," the Attorney General argues that any application by Consumers requesting an FCM as prohibited would be in contravention of

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[416] 2 Tr 461.
[417] 2 Tr 462-463, citing Case No. U-21090, Settlement Agreement, par. 10.
[418] 2 Tr 469.
[419] AG initial brief, p. 38.
[420] AG initial brief, p. 39.

the standing settlement obligations and Commission Order.[421] The Attorney General asserts that PA 235 did not require Consumers to request an FCM as part of its application in this case, and notes that as a matter of long-established law in Michigan, a party may be required by agreement to forbear from otherwise legal conduct.[422] As such, the Attorney General concludes that while PA 235 permits recovery of a financial incentive, the statute did not absolve Consumers of its standing obligation to refrain from requesting an FCM in its REP application or its request for a pre-tax WACC under PA 235.[423]

Noting that the basis for the Attorney General's recommendation is the "settlement language" in the 2021 IRP, Case No. U-21090, which restricted Consumers' from applying a FCM to new PPAs in the REP, Consumers counters that that the FCM agreed to in Case No. U-21090 was permitted under Act 341 of 2016, was generally applicable to contracts established pursuant to Consumers' IRPs, was capped at Consumers' WACC, was not limited to renewable energy resources, and was applicable to all PPAs with non-affiliated companies.[424] Consumers asserts that the enactment of Act 235 changed the statutory framework, arguing that MCL 460.1028 authorizes an annual financial incentive for a rate regulated electric provider, and that the FCM calculation is not limited to Consumers' prevailing WACC and that Consumers' eligibility is not subject to Commission discretion.[425]

This PFD agrees with Consumers. While Consumers did previously agree pursuant to the settlement agreement that the FCM would not apply to any PPA's

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[421] Id.
[422] AG reply brief, p. 11.
[423] Id.
[424] Id., p. 51-52.
[425] Id.

executed under the REP, among other restrictions, Consumers' agreement was made in the context of a second contested case challenging whether Consumers should have any FCM, which case was prosecuted when the applicable statute provided that the Commission had the discretion to either approve or not approve an FCM. Clearly, Consumers would not agree to the limited settlement FCM terms approved in the prior IRP cases today when all of the FCM terms under the revised statutes were available to it without any contest.

Moreover, the new, amended statutory provisions expressly state that the provisions "appl[y] to any contract entered into after June 30, 2024".

Thus, this PFD recommends that the Commission reject the Attorney General's objection to the FCM.

ABATE disagrees with Consumers' proposal to collect the FCM through the PSCR rather than the existing FCM surcharge.[426] Ms. York states that Consumers' REP reflects the recovery of an FCM through the PSCR mechanism for contracted renewable energy resources for which contracts have been entered into after June 30, 2024, while for PPAs entered into before June 30, 2024, the contract price is recovered through the PSCR and the FCM recovered through a FCM surcharge.[427] She adds that Consumers has not explained the rationale for this proposal.[428] She asserts that this change would reduce transparency for ratepayers relative to the current FCM surcharge method, which transparency into the rate impact of the FCM she asserts should be maintained, particularly as the amount of the FCM is projected to increase significantly in future

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[426] 4 Tr 723.
[427] 4 Tr 724.
[428] 4 Tr 725

years.[429] In addition, she asserts that Consumers has not explained its intention regarding the allocation of the FCM if it is recovered through the PSCR.[430]

Consumers counters that the FCM is a cost of the renewable energy contract and, as such, it is most appropriate to recover it from the PSCR directly.[431] Mr. Johnston states that Consumers considered trying to combine the two different FCMs for administrative ease but ultimately felt that the previously established methodology established pursuant to prior Commission orders was not appropriate for the newly established FCM and would lead to a significant increase in the surcharge based upon uncertain projections and carrying charges for both over-collections and under-collections.[432] Further, he adds that the calculation methodology and resource type applicability for each of the FCMs are different.

Noting that Consumers argued that "the FCM is a cost of the renewable energy contract, which makes it appropriate to collect through the PSCR," and expressed concern that "the previously established methodology was not appropriate for the newly established FCM and would lead to a significant increase in the surcharge based upon uncertain projections and carrying charges for both over-collections and under-collections," ABATE argues that Consumers' claim and concern, even if valid, do not justify revising the existing FCM collection approach.

> The Company's proposal would unnecessarily and unreasonably reduce transparency for ratepayers and effectively eliminate their visibility into the Company's incentive award for PPAs. First, despite the Company's claim, the FCM is not a "cost" of the renewable energy contract; it is an incentive the utility can pursue for entering into that contract, not a cost of the contract itself. As such it

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[429] Id.
[430] Id.
[431] 2 Tr 80.
[432] Id.

> should be identified and treated distinctly from the Company's general power purchase costs and not subsumed within them through the PSCR process. Second, the Company's claim regarding the method of calculating the FCM is irrelevant. Whether or not the FCM for new renewable energy contracts is *calculated* differently from the current FCM makes no difference to the appropriateness of the current *collection method*. The FCM is still an incentive for entering into renewable energy contracts. A surcharge is therefore the most straightforward and transparent way of accounting for and collecting this "cost" to customers, which is unrelated to the actual power purchased through the renewable energy contract.
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> Stated differently, the FCM is an incentive award based on the Company's choice of resource, not a direct cost of power supply. The FCM should thus be separately accounted for when charged to customers. The Company's proposal would instead limit customers' ability to discern what REP and PPA costs the utility is collecting.[433]

This PFD agrees with ABATE that the FCM is still an incentive for entering into renewable energy contracts, and that a surcharge is the most straightforward and transparent way of accounting for and collecting this cost to customers, which is unrelated to the actual power purchased through the renewable energy contract. This PFD also agrees that Consumers' proposal would reduce transparency for the ratepayers to discern what REP and PPA costs the utility is collecting. Thus, this PFD recommends that the Commission should therefore reject Consumers' proposal and require that Consumers' FCM continue to be recovered through the surcharge.

J. Approval of Solar Contracts

In its rate case (Case No. U-21585), Consumers projected capital expenditures for four solar projects, including the Mustang Mile, Washtenaw, Muskegon, and Spring Creek solar projects.[434] In that case, Staff recommended that these projections be removed from base rates because they should be included in Consumers Amended REP in this case.[435]

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[433] ABATE reply brief, p. 1-2. Emphasis in original, citation omitted.
[434] Consumers initial brief, p. 53, citing Case No. U-21585, Order, March 21, 2025, p. 158.
[435] Case No. U-21585, Order, March 21, 2025, p. 158.

Consumers agreed to include the projects in this case with the understanding that Consumers may bring these projects for recovery in a future rate case if they are denied in this case.[436] The PFD found that, given the apparent agreement between the Staff and Consumers, Consumers should seek recovery of the four solar projects in this case and, if recovery is denied, recovery in a future electric rate case.[437] The PFD also stated that the Attorney General's proposed disallowances -- the Attorney General had recommended that capital expenditures related to the Washtenaw, Muskegon, and Spring Creek solar projects be removed from the rate case because all have seen construction delays and delayed commercial operation dates (CODs) to the extent that none of the projects will be operational in the projected test year -- are moot considering Consumers' agreement to move the solar projects to this RE Plan case.[438] The Commission adopted the PFD's findings and conclusions on this issue.[439]

Accordingly, Consumers presented the costs for these four solar projects in this case. Consumers states that the Spring Creek Project is a 140 MW self-perform solar facility project located in Calhoun County and Barry County and all major agreements have been executed and work toward delivery of the project is proceeding.[440] Similarly, Consumers states that the Muskegon Solar Project is a 250 MW self-perform solar facility project located in Muskegon County and all major agreements have been executed, work

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[436] Id.
[437] Id. Citation omitted.
[438] Id.
[439] Id., p. 159.
[440] Id., citing 2 Tr 220; Ex. A-22.

toward delivery of the project is proceeding, and the project will achieve COD on or before December 31, 2025.[441]

Consumers states that the Washtenaw Solar Project is a 150 MW solar facility project located in Washtenaw County, and while the project has secured land rights for more than 1,100 acres, changes to the Saline Township zoning ordinances enacted after execution of the build transfer agreement ("BTA") will require additional land rights in order to be sited locally or will need to rely on the state certification process.[442] Consumers adds that it is working with the developer of the project, Invenergy, on a revised schedule and cost for the project, and once completed, will present the agreement to the Commission for approval.[443]

Consumers states that the Mustang Mile Solar Project is a 150 MW solar facility project located in Lenawee County, and that while the project has secured all land rights and a special land use permit has been granted, legal challenges to the permit are currently being litigated in the Michigan Court of Appeals, resulting in delays, and a revision to the original project schedule.[444] Consumers is working with Invenergy on a revised schedule and cost for the project and, once completed, will present the agreement to the Commission for approval.[445]

The Attorney General asserts that the Mustang Mile and Washtenaw solar projects currently do not have expected CODs due to significant delays these projects have

[441] Id., p. 54, citing 2 Tr 222; Ex. A-15.
[442] Id., citing 2 Tr 222-224.
[443] Id., citing 2 Tr 224.
[444] Id., p. 54-55, citing 2 Tr 224-225.
[445] Id.

experienced.[446] In this regard, the Attorney General states that in its prior electric rate case, Consumers acknowledged that the unpredictable nature of pending legal proceedings and timelines made it so that it could not give an accurate Commercial Operations Date ("COD") for the Mustang Mile solar project.[447] Mr. Deupree also states that while Consumers states that it "expects" the Washtenaw project to begin commercial operations on December 7, 2026, Consumers indicated in its electric rate case that the earliest the Washtenaw Solar Project would be in operation is late 2027, and that Consumers confirmed in discovery in this case that it had no updates on the status of the Washtenaw project since what was provided to parties in its electric rate case.[448] Thus, he recommends costs associated with Mustang Mile and Washtenaw solar projects be excluded from Consumers' proposed amended REP, adding that these projects can be included in future amended REPs once greater certainty is known regarding the viability of these projects and anticipated COD.[449]

As such, the Attorney General asserts that Consumers has failed to show how inclusion of these projects is reasonable and prudent under its projections for cost recovery and meeting its REC portfolio requirements.[450] The Attorney General argues that if these solar projects never come online, the Company will be left with a generation gap associated with the loss of 300 MW36 of generation capabilities, which it otherwise would not have planned to fill in the interim.[451] In addition to the removal of the costs associated

[446] 2 Tr 453.
[447] 2 Tr 454.
[448] 2 Tr 455-456. Citations omitted.
[449] 2 Tr 456.
[450] AG initial brief, p. 12.
[451] Id.

with these projects, the Attorney General recommends that the Commission require the Company to identify replacement RECs for these projects within its plan until the roadmap for their completion becomes more concrete.[452]

Consumers counters that removal of these projects from the Amended REP would be contrary to Act 295 because it would make the planned costs and resources needed to comply with the renewable portfolio standard incomplete.[453] Consumers states that it is required to include in its Amended REP a "forecast of the renewable energy resources needed to comply with the renewable energy credit standard" (MCL 460.1022(3)), a "mechanism for the recovery of the incremental costs of compliance" MCL 460.1022(2)), and costs associated with the "renewable energy portfolio established to achieve compliance with the renewable energy standards" (MCL 460.1047(2)(a)(i)), and that consistent with these requirements, Consumers included the Washtenaw and Mustang Mile solar projects in its Amended REP because they represent renewable energy resources that Consumers is planning to use for compliance.[454]

Mr. Clark states that while some uncertainty exists regarding when the Mustang Mile and Washtenaw Solar projects will achieve commercial operation, both projects are the result of competitive solicitations that were conducted pursuant to a Commission-approved IRP.[455] He adds that the inclusion of these projects in Consumers' Amended REP is an acknowledgment that these projects will serve as resources utilized to meet the RPS and therefore costs associated with them should flow through the Amended REP

[452] AG initial brief, p. 13.
[453] Consumers initial brief, p. 55.
[454] Consumers initial brief, p. 55, citing 2 Tr 229.
[455] 2 Tr 229.

process, including the REP Reconciliation.[456] He asserts that the uncertainty of the COD has no bearing on the appropriateness of including the projects within this Amended REP.[457] Consumers' states that many of the projects included in the Amended REP are not yet in development and thus have greater uncertainty than the Mustang Mile and Washtenaw projects.[458]

Mr. Bleckman states that the Mustang Mile project was approved on April 8, 2021 in Case No. U-20165 and the Washtenaw project was approved on November 28, 2021 in Case No. U-20165.[459] He asserts that both the costs of compliance and PSCR transfer costs would be dramatically under-projected as a result of excluding these in-development projects.[460] He adds that there is no present customer rate or cost from Consumers including Mustang Mile, Washtenaw, or any projected renewable facilities in its Amended REP filings.[461]

This PFD agrees with the Attorney General that the Mustang Mile and Washtenaw solar projects should be excluded from this amended REP. Consumers acknowledges the delays and uncertainty associated with these two projects and while it believes that the challenges to these projects will be resolved favorably, any such resolutions are unclear at this time. Thus, this PFD recommends that the Commission exclude from Consumers' proposed amended REP the costs associated with Mustang Mile and Washtenaw solar

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[456] Id.
[457] Id.
[458] Consumers initial brief, p. 56, citing 2 Tr 191.
[459] 2 Tr 192.
[460] 2 Tr 193.
[461] Id.

projects, and that Consumers be required to identify replacement RECs for these projects within its plan.

K. Other Issues

1. BMP Resources

The BMPs argue that Consumers' amended REP contains "serious flaws" and fails to satisfy the requirements of both the statute and the Commission's Filing Requirements.[462] Specifically, Mr. Polich testified that the REP fails to include a mix of all existing, indigenous Michigan renewable generation resources because it does not include any non-intermittent, baseload dispatchable renewable generation, which the BMPs can provide.[463] He opined that Consumers purposely excluded the BMPs, which have a proven 93.0% availability factor, from the renewable generation resource mix proposed in the REP.[464] He further stated that Consumers disregarded MCL 460.1001(2) by failing to enter into discussions with the BMPs about the possibility of including their generation in the REP beyond their current contract expiration dates.[465]

Mr. Polich further testified that Consumers' amended REP includes only intermittent, non-dispatchable solar generation (8,000 MWs with an assumed capacity factor of 23%) and wind generation (2,800 MWs with a capacity factor of 29%).[466] He testified that Consumers' failure to include the BMPs in its proposed mix of renewable resources is particularly problematic because Consumers' assumed solar capacity factor

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[462] BMPs initial brief, 1.
[463] 2 Tr 264.
[464] 2 Tr 264, citing Exhibit BMP-3.
[465] 2 Tr 264, citing Exhibit BMP-4.
[466] 2 Tr 264, 266.

is grossly overstated and incorrect.[467] He testified that, as the Company had done in its 2021 Integrated Resource Plan case, Consumers assumes a solar capacity factor of 23%, which is not supported by the Company's data showing that historical average capacity factors of its existing solar projects range between 18.1% and 21.2%.[468] Mr. Polich explained that based on additional historical solar operating data Consumers provided, he revised his testimony to reflect a realistic projected solar capacity factor of 20.5% for utility-scale projects, while he opined that an appropriate capacity factor for smaller solar projects is in the 19% range.[469] He testified that the overstated capacity factor results in an understated solar LCOE, which in turn "virtually ensure[s]" that Consumers' actual costs for the 8,000 MW of solar for which it has requested ex parte contract approval will exceed its stated LCOE.[470]

Mr. Polich testified that unlike Consumers' proposed solar and wind capacity, the BMPs can provide baseload, continuous dispatchable energy around the clock with an average annual availability of 93.0% and a capacity factor of 100%.[471] He stated that the BMPs can provide this performance at costs equivalent to or lower than any LCOE associated with combinations of renewable energy generation and energy storage Consumers has included in its REP.[472] He stated that the BMPs' 183.17 MW of capacity could replace 692 MW of solar capacity using Consumers' "overstated" 23% capacity

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[467] 2 Tr 264.
[468] 2 Tr 265, 268-269, citing Exhibits BMP-5 and BMP-14.
[469] 2 Tr 268, 314-315. Mr. Polich testified in rebuttal that Consumers initially failed to provide 2024 solar project data contained in Exhibit A-40 and that the BMPs did not receive that data until April 16, 2025. 2 Tr 310-311. Mr. Polich revised his direct testimony to reflect that data. *Id.*
[470] 2 Tr 265.
[471] 2 Tr 265-266, 274, citing BMP-3.
[472] 2 Tr 265.

factor and could replace approximately 776.4 MW of solar generation using the actual 20.5% capacity factor of Consumers' existing solar facilities.[473] Mr. Polich testified that "no reasonable combination of renewable generation resources and energy storage proposed by Consumers in the Amended REP can provide the same 24/7 generation performance as the BMPs."[474]

Mr. Polich stated that Consumers' solar LCOE of $70.31/MWh is erroneous; correcting the solar average capacity factor to 20.5% and reducing its lifecycle to 30 years (instead of 35 years) raises the LCOE to $84.36/MWh.[475] He asserted that replacing solar capacity with BMP capacity could reduce the cost of the REP by over $3.5 billion over the solar projects' life.[476] He further stated that replacing wind capacity with the BMPs' capacity would lower the cost of the REP by $2.3 billion over the wind projects' life.[477] Mr. Polich stated there could be further savings if the actual solar and wind LCOE increase by 40% and when storage is considered:

> If the solar LCOE were to increase by 40%, the solar LCOE would be $126.95/MWh and the wind LCOE would be $77.62/MWH. Adding energy storage at 140% of the $143.54/MWh LCOE, to the solar LCOE, would raise solar LCOE to $154.59/MWh[.] Consumers' ratepayer cost reduction of replacing solar with the BMPS, would be $5.3 billion for solar and $3.2 billion for wind generation over the 30 year life of the generation resource.[478]

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[473] 2 Tr 265, 286, 288.
[474] 2 Tr 265.
[475] 2 Tr 291-292; see 2 Tr 308-310.
[476] 2 Tr 265, 290.
[477] 2 Tr 290.
[478] 2 Tr 290.

In addition, he testified that using Consumers' 23% solar capacity factor results in a shortfall of over 1.98 million RECs in 2040, resulting in Consumers' renewable compliance of only 55.5% instead of 60%.[479]

Mr. Polich opined that given Consumers' failure to include the BMPs in its renewable generation mix, the Commission should find the REP is not prudent and economical for failing to satisfy statutory requirements and causing an unnecessary and avoidable increase in customer rates.[480] He continued, "This is particularly appropriate given Consumers' request for Ex Parte approval of wind and solar contracts priced at 140% of their already understated LCOE."[481] Mr. Polich recommended that the Commission require Consumers to conduct an RFP for biomass generation resources that recognizes the various benefits of biomass generation over other intermittent, invertor-based renewable generation.[482] He also recommended that the Commission require Consumers to refile its REP "utilizing realistic solar capacity factors that are based on known solar project performance of existing Michigan based solar generation resources."[483]

In rebuttal, Mr. Cole testified that Consumers does not have enough utility-scale solar projects in its portfolio to state that the assumed 23% solar capacity factor is not realistic, and he noted this is the same solar capacity factor that was utilized in its 2021 IRP, Case No. U-21090.[484] He testified that Mr. Polich erroneously relied on Exhibit BMP-

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[479] 2 Tr 297.
[480] 2 Tr 266.
[481] 2 Tr 266.
[482] 2 Tr 266, 297.
[483] 2 Tr 270, 298, 315.
[484] 2 Tr 349.

5 to reach conclusions about the historical capacity factors of the Company's existing solar projects. He stated that Exhibit BMP-5 includes data from smaller projects, projects that were incorrectly listed, and a project that was not fully operational.[485] He also stated that Exhibit BMP-5, page 2, is not historic generation data but rather a forecast.[486]

Mr. Cole sponsored Exhibit A-40, which provides Company owned or contracted generation data for solar facilities 5 MW and larger that were in operation for the full 2024 calendar year.[487] He testified that the exhibit shows that most of the Company's owned or contracted solar facilities that were online for all of calendar year 2024, and had nameplate capacities 5 MW or greater, had capacity factors above 19.4%.[488] He stated, however, that Exhibit A-40 only shows solar generation data for a single year and does not provide enough data to make changes to the Company's long-term solar capacity factor assumption.[489] Mr. Cole testified that long-term forecasting should not be based on a single year's generation values since solar production can vary year to year, and the dataset is relatively small, containing only 530 MW, in comparison to the total amount of solar included in this REP.[490] Mr. Cole concluded that the Company should not be required to adjust its solar capacity factor for this case, but he stated that the Company's long-term plan for renewable portfolio standard compliance and its utility-scale solar capacity factor assumptions will be reevaluated in its next amended REP.[491]

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[485] 2 Tr 349-350.
[486] 2 Tr 350.
[487] 2 Tr 350.
[488] 2 Tr 350-351.
[489] 2 Tr 351.
[490] 2 Tr 351.
[491] 2 Tr 351-352.

Mr. Cole disagreed with Mr. Polich's claim that the Company's LCOE of $70.31/MWh is incorrect.[492] He testified that a 35-year solar lifecycle is used in the LCOE calculation because the number aligns with assumptions used in recent Company RFPs for solar resources.[493] He also stated that Mr. Polich does not provide any valid data to support his claim that the 23% solar capacity factor is not realistic.[494]

Mr. Cole also disagreed with Mr. Polich's calculations of the potential savings from utilizing the BMPs' capacity. He stated that Mr. Polich's calculations fail to account for the costs associated with BMP contracts; "These values were obtained by estimating the costs associated with acquiring BMP equivalent RECs (1,394,193 annually) via solar [and wind] resources, however, they do not consider the costs to acquire this quantity of RECs from the BMPs."[495] He explained that it is difficult to assess the potential impact to ratepayers by including the BMPs in Consumers' REP since the impact is dependent upon a BMP $/MWh price assumption.[496] Mr. Cole testified that using the BMPs' calculation methodology and value for BMP equivalent RECs of 1,394,193 annually, and if it is assumed that the BMPs' future $/MWh price is roughly equivalent to the BMPs' three-year historic average cost of $108.47/MWh, as shown in Exhibit A-42, then there are no cost savings by including the BMPs in the REP.[497] He stated that Exhibit A-43 shows that comparing the costs of the BMPs to the cost of solar results in an estimated $53.2 million higher cost per year or an estimated $1.86 billion higher cost over the 35-

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[492] 2 Tr 352.
[493] 2 Tr 352.
[494] 2 Tr 352.
[495] 2 Tr 353-354.
[496] 2 Tr 354.
[497] 2 Tr 354-355.

year solar useful life.[498] He further stated that comparing the costs of the BMPs to the cost of wind results in an estimated $73.9 million higher cost per year or an estimated $2.97 billion higher cost over the 30-year useful life of wind.[499]

In his rebuttal, Mr. Polich testified that Mr. Cole's testimony regarding the useful life of solar plants being 35 years contradicts the 30-year useful life used in the 2021 IRP, contradicts Mr. Johnston's initial testimony, contradicts Consumers' discovery responses, and is not consistent with Consumers' draft 2025 Request for Proposals for All Generation Sources.[500] He stated that Mr. Cole did not provide any evidence to support his position that solar projects have a 35-year useful life.[501]

Mr. Polich further testified that Consumers effectively takes the position that historical data does not matter and that the Commission should simply accept Consumers' assumed solar capacity factor of 23% regardless of evidence to the contrary.[502] He stated that Exhibit A-40 contains 18 solar projects with average annual solar capacity factors ranging from 17.9% to 21.8%.[503] Based on Exhibit A-40, Mr. Polich testified that larger utility-scale Michigan solar projects have a capacity factor of around 21.8%.[504] He stated that while Exhibit A-40 represents only one year of solar data for those projects, Exhibit BMP-14 provides an analysis of the data provided in Consumers' Discovery Response U-21816-BMP-CE-0193, which includes average capacity factors

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[498] 2 Tr 355.
[499] 2 Tr 355; Exhibit A-43.
[500] 2 Tr 308-309.
[501] 2 Tr 309.
[502] 2 Tr 311.
[503] 2 Tr 312.
[504] 2 Tr 314.

for the period of 2021-2024.[505] He testified that the average capacity factor of the 18 solar projects for the period of 2021–2024 falls to 21.2%.[506] He further explained that of the 18 solar projects, only six have multiple years of operation.[507] He stated those six projects' average solar capacity factor average 0.7% less than the 2024 capacity factor, and a few of the solar projects' average capacity factor is over 1% lower than the 2024 capacity factor.[508] He concluded, "This analysis indicates that 2024 is likely a high solar production year and the average solar capacity factor over multiple years is lower than 21.8%."[509]

Mr. Polich testified that while Consumers has stated that the BMPs have the opportunity to bid into its All Sources Energy Generation Projects RFP, the 2025 RFP does not provide the opportunity for the BMPs to bid into renewable energy generation sources.[510] He stated that the definition of "Clean Energy" contained in the 2025 RFP would exclude the BMP projects from three of the Tranches.[511] In addition, he stated that Tranche 13-16 contains commercial operation dates for the PPAs which occur while several of the BMPs are still under contract with Consumers, which would exclude the BMPs' participation in this RFP.[512]

In briefing, Consumers relies on Mr. Cole's testimony to argue that the Company's solar capacity factor is consistent with the Company's 2021 IRP and is based on the limited data available from utility-scale solar projects in the Company's portfolio.[513] It

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[505] 2 Tr 314.
[506] 2 Tr 314.
[507] 2 Tr 314.
[508] 2 Tr 315.
[509] 2 Tr 314-315.
[510] 2 Tr 315.
[511] 2 Tr 315-316.
[512] 2 Tr 317.
[513] Consumers initial brief, 57-58.

argues that the data Mr. Polich relied upon "should not be considered reliable for altering capacity factor assumptions."[514] Consumers states that it will reevaluate its long-term plan for REC compliance and its utility-scale solar capacity factor assumptions in its next amended REP, which it will be filing two years from the order in this case.[515]

Consumers also argues that Mr. Polich's alternative LCOE of $84.36/MWh is based on unsupported assumptions and does not reflect the Company's actual modeling practices.[516] It argues that Mr. Polich's cost-savings calculations are flawed because they fail to account for the costs associated with BMP contracts and incorrectly assume BMPs can replace solar capacity on a one-to-one basis.[517]

Finally, Consumers states that while it did not include the BMPs in the results of its amended REP, the Company undertakes Clean Energy solicitations, as well as all resource solicitations.[518] It states that, most recently in 2024, the Company solicited for up to 1,500 MW of clean generation to serve the Company's IRP, VGP, and the REP. Consumers states that the BMPs are able to participate, and therefore their positions should be rejected.[519]

The BMPs rely on Mr. Polich's testimony to argue that Consumers' 23% solar capacity factor is flawed and that the Commission should require Consumers to revise its REP to reflect prudent and realistic projected solar capacity factors of 19% for smaller solar projects and 20.5% for utility-scale solar projects.[520] They argue that Consumers

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[514] Consumers initial brief, 58.
[515] Consumers initial brief, 58.
[516] Consumers initial brief, 59.
[517] Consumers initial brief, 59.
[518] Consumers initial brief, 60.
[519] Consumers initial brief, 60.
[520] Consumers initial brief, 5-11.

should replace 776.4 MW of solar generation with the BMPs' 183.17 MW of capacity.[521] The BMPs also state that Consumers' testimony regarding the useful life of solar plants is flawed and Consumers' LCOE calculation is flawed.[522]

The BMPs argue that ratepayers can benefit from replacing some solar and/or wind generation with generation from the BMPs; the BMPs' MISO Seasonal Capacity Accreditation far exceeds the accreditation for wind and solar; and purchasing generation from the BMPs avoids the construction, interconnection, and financial risks associated with new construction.[523] They argue that Consumers failed to consider the in-state employment and tax benefits of the BMPs.[524]

The BMPs argue that because the REP fails to adequately consider generation diversity and actively decreases the diversity of generation supply, it fails to meet the statutory requirement of MCL 460.1001(2)(a).[525] They further argue that the REP fails to recognize the significant differences among generation types and recommend that the REP be revised to distinguish between intermittent and non-intermittent renewable generation in a manner similar to FERC's approach in allowing for multi-tiered avoided costs under PURPA.[526]

The BMPs argue that Consumers wrongfully excluded them from both its REP and its 2025 All Resources Generation RFP.[527] They argue that the Company should conduct

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[521] Consumers initial brief, 11.
[522] BMPs initial brief, 12-14.
[523] BMPs initial brief, 14-18.
[524] BMPs initial brief, 19.
[525] BMPs initial brief, 18.
[526] BMPs initial brief, 4, 20-22.
[527] BMPs initial brief, 23-24.

an RFP for biomass generation resources that recognizes the benefits of biomass generation.[528] They also state:

> The BMPs represent only 183.17 MW of capacity, which is only 2.28% of Consumers' proposed 8,000 MW of solar additions. There is currently only a small amount of non-intermittent, baseload, renewable generation available to back-stop the renewable intermittent solar and wind generation and the Commission should not facilitate Consumers' actions to put the BMPs out of business. Doing so is flatly inconsistent with the President's recent April 8, 2025 Executive Order preventing certain resources greater than 50MW from leaving the bulk power system and Governor Whitmer's recent statement voicing support for renewable biomass generation. The Executive Order applies to TES Filer City Station which is larger than 50MW and because the remaining BMP's have a collective capacity greater than 50MW, the same logic supports continuing their operation.[529]

In reply, Consumers states that the Company's proposal for solar resources and its solar capacity factor are incorporated into the REP from the Company's most recent IRP, consistent with the Commission's guidance from Case No. U-21568.[530] Consumers quotes the Commission's instruction that "IRPs remain the most appropriate venue to consider generation diversity as well as renewable resource planning because IRPs allow for the full assessment of renewable resources against other resources."[531]

In their reply brief, the BMPs reject Consumers' contention that the solar capacity factor should be considered in the next IRP rather than in this REP:

> Consumers ignores the facts that both Act 235 of 2023 and the Commission's Filing Requirements for Renewable Energy Plans post-date the Company's 2021 Integrated Resource Plan proceeding, Case No. U-21090, by more than 2 years. That proceeding was an Integrated Resource Plan ("IRP") proceeding. This proceeding is a Renewable Energy Plan case. It defies logic to conclude that this Renewable Energy Plan should accept the 23% solar capacity factor from its 2021 IRP when (i) neither Act 235's statutory requirements nor the Commission's Filing Requirements for

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[528] BMPs initial brief, 25.
[529] BMPs initial brief, 3 (internal citations omitted).
[530] Consumers reply, 11, citing Case No. U-21568, April 25, 2024 Order, pp. 19-20.
[531] Consumers reply, 12, quoting Case No. U-21568, April 25, 2024 Order, p. 19.

> Renewable Energy Plans existed in 2021, (ii) the correct solar capacity factor data are directly relevant to the question of whether Consumers' Amended REP satisfies the requirements of Act 235 and the Commission's Filing Requirements, and (iii) substantial solar capacity factor data is now available that was not available in 2021. As explained in the BMPs Initial Brief, Consumers' Amended REP fails to meet the requirements of both Act 235 and the Commission's Filing Requirements.[532]

This PFD does not find the BMPs' objections to the Company's amended REP compelling for several reasons. First, the Commission has determined that IRPs are the most appropriate venue for considering generation diversity and renewable resource planning, and "amended REPs should reflect the assumptions included in the providers' most recently approved IRP."[533] While the initial amended REP under Act 235 need not align with the previous IRP if that IRP fails to reflect the renewable energy build out necessary under Act 235,[534] this PFD does not find that exception applies here. Instead, Consumers incorporates the same 23% solar capacity factor that it used in its most recent IRP (Case No. U-21090), and this PFD finds that factor to be reasonable. Consumers has shown that the data on actual solar performance is too limited to warrant an adjustment to the solar capacity factor at this time. It has also established that the BMPs rely on flawed data to support their argument.[535] Issues involving solar or wind capacity are essential to the modeling that is done in IRP proceedings. Therefore, Consumers' solar capacity factor should be assessed in its next IRP, with the benefit of additional data.

Next, this PFD finds Consumers' presentation on forecasted solar LCOE to be more persuasive. As discussed above, the BMPs rely on an erroneous capacity factor to

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[532] BMPs reply, 1-2.
[533] Case No. U-21568, Order, April 25, 2024, p 19.
[534] Case No. U-21568, Order, April 25, 2024, p 20.
[535] See 2 Tr 349-351.

support a higher LCOE. In addition, this PFD is not convinced that Consumers' 35-year solar lifecycle assumption used to calculate the LCOE is unreasonable.[536]

This PFD also agrees with Consumers that the BMPs' calculation of potential savings from substituting solar or wind with biomass power is flawed because it fails to account for the costs associated with the BMP contracts. As Mr. Cole explained, replicating that calculation using the BMPs' three-year historic average cost of $108.47/MWh shows there would be no cost savings by including the BMPs in this REP, and, in fact, it would result in higher costs. In any event, the appropriate forum for addressing the optimal resource mix going forward is the Company's next IRP.

Finally, this PFD rejects the BMPs' contention that they have been effectively excluded from participating in the RFP process because several of the BMPs are still under contract with Consumers and were therefore excluded from bidding in the 2025 All Resources Generation RFP. This does not establish that the RFP process is somehow flawed or that those BMPs currently under contract will be unable to participate in future RFPs.

2. Length of Renewable Energy Plan

Staff requests that the Commission clarify whether the 20-year period set forth in MCL 460.1045 is meant to have a finite end date or whether this 20-year period resets as of each amended REP filing.[537] During discovery, Staff witness Harlow became aware of Consumers' interpretation of the 20-year planning period within MCL 460.1045(3), which statute states: "The incremental cost of compliance shall be calculated for a 20-year

[536] See Consumers initial brief, 59.
[537] 4 Tr 797.

period beginning with approval of the amended renewable energy plan and may be recovered on a levelized basis." In its discovery response, Consumers stated that when it files its next Amended REP in two years, it intends the 20-year period to be a "rolling 20-year period".[538] In his subsequent testimony, while noting that PA 295, as amended by PA 342, contemplated a 20-year renewable energy plan period with a finite ending date taking place in 2029, Mr. Harlow asserts that it is unclear to Staff whether PA 235 also established a finite Amended REP ending date.[539]

Mr. Harlow states that, while the operative language of PA 295, as amended by PA 342, Section 45(4) [MCL 460.1045(4)] -- "The incremental cost of compliance shall be calculated for a 20-year period beginning with approval of the renewable energy plan and shall be recovered on a levelized basis" – is maintained in PA 235, as amended by PA 342 [MCL 460.1045(3)], PA 235 omits several references to the expiration of the 20-year period found in PA 295, as amended by PA 342.[540]

Mr. Harlow asserts that this clarification should come in this case as this determination is necessary to calculate the levelized ICOC recovery as established in MCL460.1045(3) for all future Amended REPs filed biennially and any potential adjustments in Reconciliations.[541] He states that Staff's preference between a fixed 20-year period and a rolling 20-year period is a fixed 20-year period, asserting that it establishes a fixed period for levelization of the incremental cost of compliance ("ICOC"), as opposed to a new levelization period every Amended REP.[542] He adds that a fixed

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[538] Ex. S-1, p. 15.
[539] 4 Tr 797. Emphasis removed.
[540] 4 Tr 797-799.
[541] 4 Tr 800.
[542] Id.

period would help to encourage a regulatory balance that is as near to zero as possible in the out years.[543] He acknowledges that Staff does not view clarification regarding how to handle an ICOC regulatory balance as imperative, as Staff asserts that it would recommend modifications in annual Reconciliations and biennial Amended REPs to ensure that the regulatory liability remains relatively neutral in the future.[544]

In support of a rolling 20-year period, Consumers reiterates Mr. Harlow's testimony which noted that Act 235's amendment of Act 295 removed several references regarding the expiration and conclusion of the 20-year RE Plan period.[545] Consumers states that it will file an amended REP within two years after an order approving the last amended REP, and each amended REP will include a calculation of the ICC "for a 20-year period beginning with approval of the amended renewable energy plan."[546] Consumers asserts that each amended REP filing will include an updated 20-year plan period for calculating the incremental costs of compliance, and that through these regular amended REP filings, Consumers will be able to make adjustments as needed to minimize the regulatory liability balance, including potentially reducing the transfer price and implementing a credit surcharge.[547]

This PFD disagrees with Staff that its requested clarification needs to come in this case. Staff acknowledges that it will recommend modifications in annual reconciliations and biennial Amended REPs to ensure that the regulatory liability remains relatively

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[543] Id.
[544] Id.
[545] Consumers initial brief, p. 61, citing 2 Tr 797-799.
[546] Id., citing MCL 460.1022(3), 460.1045.
[547] Id., citing 2 Tr 59.

neutral in the future. Moreover, any such clarification will involve application of statutory construction principles to the various versions of the statutory sections which were comprehensively amended, and in this case, no party other than Staff provided any testimony on how these amended provisions should be interpreted. Thus, this PFD finds that the best practice would be for the Commission to forgo making any clarification in this case and until other parties have offered testimony and legal support on the question in a subsequent case.

3. REP Statutory Timeline and Contract Approval

GLREA asserts that the Commission should reject or modify Consumers' REP.[548] Mr. Rafson states that the Commission should look at only one or two years of the plan and decide if the first year or two is appropriate and ask for the REP to be reworked for submittal next year or the following year, when by then some of the important federal budget issues and other department changes should be clarified.[549] He adds that the re-worked REP would be much more realistic and could incorporate the other recommendations provided in his testimony and likely other interveners' testimony.[550]

Mr. Rafson argues that cost recovery should be made in rate cases as it always as been done.[551] He asserts that plan cases should only reflect the plans and determine if the plans are reasonable and prudent, and that plan cases are not a place for cost recovery, especially for very long-term investments like those proposed in this REP and especially during very volatile economic times.[552]

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548 GLREA initial brief, p. 21.
549 4 Tr 613.
550 Id.
551 Id.
552 4 Tr 613-614.

Mr. Rafson argues that if the Commission approved cost recovery in the REP, the Commission effectively approves the prices presented as recoverable cost.[553] He asserts that plans should not be construction-approved bids and ratepayers should not be burdened by cost recovery based upon estimates but rather should cover actual costs.[554]

Mr. Johnston counters that Consumers is required pursuant to statute to calculate the incremental cost of compliance for a 20-year period, and that Consumers' amended REP carefully and thoughtfully lays out Consumers' current plan to achieve the REC standard through 2045.[555] He adds that MCL 460.1022(3) requires the Commission to then approve the amended REP with any changes consented to by Consumers or reject the amended REP.[556] He asserts that reviewing and approving only one or two years of Consumers' amended REP is not a viable option.[557] He states that MCL 460.1028(3) requires Consumers to file another amended REP to demonstrate its compliance with the renewable energy credit standard within two years of an order in this case.[558]

Regarding cost recovery, Mr. Johnston asserts that contrary to Mr. Rafson's beliefs regarding how cost recovery for renewable energy plans has occurred in the past, the costs for complying with the REC standard have been and will continue to be presented in renewable energy plans and have been and will continue to be reconciled annually in renewable cost reconciliation cases.[559] He notes that while Act 235 has added an option

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[553] 4 Tr 615.
[554] Id.
[555] 2 Tr 119.
[556] Id.
[557] Id.
[558] Id.
[559] 2 Tr 119.

for recovery of the incremental cost of compliance in base electric rates, Consumers has chosen not to pursue this option.[560]

Mr. Johnston states that the Commission's approval of this amended renewable energy plan is not explicitly approving cost recovery of projected costs but rather is approving Consumers' plans for the addition of renewable energy resources and the projected costs associated with Consumers' plan.[561] He adds that projects that are developed and whose levelized costs are below the LCOE thresholds will still require Commission approval, which approval can be provided on an ex parte basis, and that projects whose levelized costs are not below the LCOE thresholds will require a contested case proceeding prior to Commission approval.[562] He states that after costs are incurred, on an annual basis, Consumers files a renewable cost reconciliation in which Consumers presents its actual costs for review and approval in a contested case proceeding.[563] He asserts that Consumers has been filing renewable cost reconciliation proceedings in this manner since 2009.[564]

GLREA's objections regarding the timeline of Consumers' Amended REP are not specifically stated and are unsupported. Moreover, GLREA's requested timeline is in direct conflict with the statute. In addition, this PFD agrees with Consumers that GLREA's assertions regarding cost recovery are misguided and are in direct conflict with REP cost recovery processes. Thus, this PFD recommends that the Commission disregard GLREA's objections.

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[560] 2 Tr 119-120.
[561] 2 Tr 120.
[562] Id.
[563] Id.
[564] Id.

IV.

CONCLUSION

This PFD recommends that the Commission issue an order consistent with the findings of fact and conclusions of law outlined above.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Jonathan F. Thoits

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Administrative Law Judge

Issued and Served:
August 1, 2025