STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of Consumers Energy Company for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.)	Case No. U-21090

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 March 7, 2022.

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 March 21, 2022, at 12:00 noon, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before March 28, 2022.

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

Sally L. Wallace

Digitally signed by: Sally L. Wallace
DN: CN = Sally L. Wallace email = wallaces2@michigan.gov C = US O = MOAHR OU = MOAHR - PSC
Date: 2022.03.07 12:08:53 -05'00'

Sally L. Wallace
Administrative Law Judge

March 7, 2022
Lansing, Michigan

Table of Contents

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of Consumers Energy Company for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))	Case No. U-21090

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On June 30, 2021, Consumers Energy Company (Consumers) filed an application, with supporting testimony and exhibits, requesting approval of an Integrated Resource Plan (IRP), certain accounting authority, and other related relief.[1]

A prehearing conference was held on July 22, 2021, at which Consumers and Commission Staff (Staff) appeared. Petitions to intervene filed by Hemlock Semiconductor Operations LLC (HSC); Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondu Corporation, Viking Energy of Lincoln, LLC, and Viking Energy of McBain, LLC (individually, and collectively as the biomass merchant plants (BMPs)); Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC),

[1] On May 28, 2021, Consumers filed a Filing Announcement confirming the company's intent to submit an updated IRP by June 30, 2021. The Filing Announcement also described four public outreach events that Consumers conducted in 2020 as part of its development of its plan, as well as technical conferences the company hosted for stakeholders.

Sierra Club (SC) (collectively, MNS), Great Lakes Renewable Energy Association (GLREA), Environmental Law and Policy Center/Ecology Center/Union of Concerned Scientists/Vote Solar (collectively, the Clean Energy Organizations (CEOs)), Association of Businesses Advocating Tariff Equity (ABATE), Mackinac Center for Public Policy (Mackinac) (permissive intervention), Energy Michigan Inc., Michigan Energy Innovation Business Council/Institute for Energy Innovation/ Clean Grid Alliance (jointly, EIBC/IEI/CGA), Midland Cogeneration Venture LP (MCV), Michigan Electric Transmission Company LLC (METC), Michigan Public Power Agency (MPPA), Wolverine Power Supply Cooperative Inc. (WPSC), Residential Customer Group (RCG), Citizens Utility Board of Michigan (CUB), and Urban Core Collective (UCC) were granted. The Department of the Attorney General (Attorney General) filed a notice of intervention.

At the prehearing conference, in addition to addressing petitions to intervene, the parties set a schedule for the remainder of the proceedings consistent with the 300/360-day time requirements set forth in MCL 460.6t. A protective order was entered on July 23, 2021. On September 28, 2021, the Department of Environment, Great Lakes, and Energy (EGLE) filed an advisory opinion on Consumers' proposed IRP. On October 4 and October 21, 2021, the Commission held virtual and in-person public hearings taking comments on Consumers' application.

On October 28, 2021, the following parties filed direct testimony and exhibits: Staff, the Attorney General, GLREA, MNS, the CEOs, METC, HSC, EIBC/IEI/CGA, ABATE, Energy Michigan, the BMPs, CUB, UCC, and WPSC. On November 19, 2021, Consumers, Energy MI, the CEOs, MNS, Staff, ABATE, HSC, EIBC/IEI/CGA, WPSC, UCC, and the BMPs filed rebuttal testimony. As reflected in the docket, some of the testimony and certain exhibits were filed confidentially pursuant to the protective order.

An evidentiary hearing was conducted December 1 through December 8, 2021. On December 2, 2021, MNS filed a motion to revoke the protected status of certain portions of testimony. On December 15, 2021, Consumers and Dearborn Industrial Generator, LLC (DIG) filed responses to the motion. Oral argument on the motion was held on December 16, 2021. The motion was granted in part and denied in part in a ruling issued on December 28, 2021. On January 18, 2022, Consumers and DIG appealed the ruling.

Parties filed briefs and reply briefs on January 4 and January 28, 2022. The record in this proceeding consists of 4,094 pages of transcript and over 500 exhibits admitted into evidence.

II.

LEGAL REQUIREMENTS

Before proceeding to address the record, it is appropriate to provide an overview of the legal framework for IRP proceedings, as set forth in MCL 460.6t.

Subsection 6t(1) directs the Commission to every five years: (1) conduct assessments of energy waste reduction (EWR) and demand response (DR) potential in Michigan based on what is technically and economically feasible (MCL 460.6t(1)(a) and (b)); (2) identify federal and state laws or regulations, existing and proposed, that may affect the electric utility industry (MCL 460.6t(1) (c) and (d)); (3) identify any planning reserve margins (PRMs) or local clearing requirements (LCRs) applicable to areas in Michigan (MCL 460.6t(1)(e)); and (4) identify any modeling scenarios or assumptions an electric utility should file with its IRP, in addition to those scenarios and assumptions that the utility has developed (MCL 460.6t(1)(f)).

In response to the directive in MCL 460.6t(1)(f), the Commission opened a docket in Case No. U-18418 to establish various modeling parameters, scenarios, and sensitivities (Michigan Integrated Resource Planning Parameters or MIRPP). The Commission issued an order approving the MIRPP on November 21, 2017. In addition, on December 20, 2017, in Case Nos. U-15896 and U-18461, the Commission approved application instructions for IRP filings and IRP filing requirements, along with instructions for certificate of need (CON) alternative proposals for electric generation capacity resources.

Subsequently, in response to Executive Directive (ED) 2020-10 and Executive Order (EO) 2020-182, the Commission added additional modeling scenarios to the MIRPP in an order issued on February 18, 2021. Specifically, the February 18 order requires two model runs:

> In addition to the utility's own scenarios and assumptions and those required by the Michigan Integrated Resource Planning Parameters, that are based on the existing Environmental Policy scenario with the high load growth sensitivity of 1.5%, thereby creating a new scenario, that: (1) demonstrate a reduction in carbon emissions by at least 28% of the utility's 2005 amounts by 2025, accomplished by modeling a hard cap on carbon emissions in 2025; and (2) demonstrate a reduction in carbon emissions by at least 32% of the utility's 2005 amounts by 2025, accomplished by modeling a hard cap on carbon emissions in 2025.[2]
>
> * * *
>
> The two additional modeling runs shall quantify all carbon emissions attributable to energy to serve customers' load plus internal use and losses. This includes carbon emission estimates from owned generation units, power purchase agreements, and carbon emissions attributable to market purchases and sales. For the purpose of assigning a carbon value to

[2] February 18 order, in Case No. U-18418, Ordering ¶ A.

Midcontinent Independent System Operator, Inc. and PJM Interconnection LLC market purchases, utilities should use the Midcontinent Independent System Operator, Inc. or PJM Interconnection LLC annual average.[3]

Sections 6t(3) and 6t(5) provide general requirements for IRP filings:

(3) Not later than 2 years after the effective date of the amendatory act that added this section, each electric utility whose rates are regulated by the commission shall file with the commission an integrated resource plan that provides a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations, to meet the utility's requirements to provide generation reliability, including meeting planning reserve margin and local clearing requirements determined by the commission or the appropriate independent system operator, and to meet all applicable state and federal reliability and environmental regulations over the ensuing term of the plan.

* * *

(5) An integrated resource plan shall include all of the following:
(a) A long-term forecast of the electric utility's sales and peak demand under various reasonable scenarios.
(b) The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including projected fuel costs under various reasonable scenarios.
(c) Projected energy purchased or produced by the electric utility from a renewable energy resource. If the level of renewable energy purchased or produced is projected to drop over the planning periods set forth in subsection (3), the electric utility must demonstrate why the reduction is in the best interest of ratepayers.
(d) Details regarding the utility's plan to eliminate energy waste, including the total amount of energy waste reduction expected to be achieved annually, the cost of the plan, and the expected savings for its retail customers.
(e) An analysis of how the combined amounts of renewable energy and energy waste reduction achieved under the plan compare to the renewable energy resources and energy waste reduction goal provided in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001. This analysis and comparison may include renewable energy and capacity in any form, including generating electricity from renewable energy systems for sale to retail customers or purchasing or otherwise acquiring renewable energy credits with or without associated renewable energy, allowed under section 27 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1027, as it existed before the effective date of the amendatory act that added this section.

[3] Id. at Ordering ¶ C.

(f) Projected load management and demand response savings for the electric utility and the projected costs for those programs.
(g) Projected energy and capacity purchased or produced by the electric utility from a cogeneration resource.
(h) An analysis of potential new or upgraded electric transmission options for the electric utility.
(i) Data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio.
(j) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements.
(k) An analysis of the cost, capacity factor, and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state.
(l) Projected rate impact for the periods covered by the plan.
(m) How the utility will comply with all applicable state and federal environmental regulations, laws, and rules, and the projected costs of complying with those regulations, laws, and rules.
(n) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve and the actions the utility proposes to take in order to achieve that peak demand reduction.
(o) The projected long-term firm gas transportation contracts or natural gas storage the electric utility will hold to provide an adequate supply of natural gas to any new generation facility.

Section 6t(6) sets out certain additional requirements in the event the utility proposes to add supply-side resources:

(6) Before filing an integrated resource plan under this section, each electric utility whose rates are regulated by the commission shall issue a request for proposals to provide any new supply-side generation capacity resources needed to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local clearing requirement for its customers in this state and customers the utility serves in other states during the initial 3-year planning period to be considered in each integrated resource plan to be filed under this section. An electric utility shall define qualifying performance standards, contract terms, technical competence, capability, reliability, creditworthiness, past performance, and other criteria that responses and respondents to the request for proposals must meet in order to be considered by the utility in its integrated resource plan to be filed under this section. Respondents to a request for proposals may request that certain proprietary information be exempt from public disclosure as allowed

> by the commission. A utility that issues a request for proposals under this subsection shall use the resulting proposals to inform its integrated resource plan filed under this section and include all of the submitted proposals as attachments to its integrated resource plan filing regardless of whether the proposals met the qualifying performance standards, contract terms, technical competence, capability, reliability, creditworthiness, past performance, or other criteria specified for the utility's request for proposals under this section.

Next, Section 6t(7), *inter alia*, sets time limits for the Commission's decision to accept, reject, or propose modifications to the IRP as well as certain procedural requirements:

> (7) Not later than 300 days after an electric utility files an integrated resource plan under this section, the commission shall state if the commission has any recommended changes, and if so, describe them in sufficient detail to allow their incorporation in the integrated resource plan. If the commission does not recommend changes, it shall issue a final, appealable order approving or denying the plan filed by the electric utility. If the commission recommends changes, the commission shall set a schedule allowing parties at least 15 days after that recommendation to file comments regarding those recommendations, and allowing the electric utility at least 30 days to consider the recommended changes and submit a revised integrated resource plan that incorporates 1 or more of the recommended changes. If the electric utility submits a revised integrated resource plan under this section, the commission shall issue a final, appealable order approving the plan as revised by the electric utility or denying the plan. The commission shall issue a final, appealable order no later than 360 days after an electric utility files an integrated resource plan under this section.
>
> * * *
>
> The commission shall review the integrated resource plan in a contested case proceeding conducted pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287. The commission shall allow intervention by interested persons including electric customers of the utility, respondents to the utility's request for proposals under this section, or other parties approved by the commission. The commission shall request an advisory opinion from the department of environmental quality regarding whether any potential decrease in emissions of sulfur dioxide, oxides of nitrogen, mercury, and particulate matter would reasonably be expected to result if the integrated resource plan proposed by the electric utility under subsection (3) was approved and whether the integrated resource plan can reasonably be expected to achieve compliance with the regulations, laws, or rules identified in subsection (1). The commission may take official notice of the opinion

issued by the department of environmental quality under this subsection pursuant to R 792.10428 of the Michigan Administrative Code. Information submitted by the department of environmental quality under this subsection is advisory and is not binding on future determinations by the department of environmental quality or the commission in any proceeding or permitting process. This section does not prevent an electric utility from applying for, or receiving, any necessary permits from the department of environmental quality. The commission may invite other state agencies to provide testimony regarding other relevant regulatory requirements related to the integrated resource plan.

Section 6t(8) sets forth the findings the Commission must make in order to approve an IRP:

(8) The commission shall approve the integrated resource plan under subsection (7) if the commission determines all of the following:
(a) The proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To determine whether the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs, the commission shall consider whether the plan appropriately balances all of the following factors:
(i) Resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement.
(ii) Compliance with applicable state and federal environmental regulations.
(iii) Competitive pricing.
(iv) Reliability.
(v) Commodity price risks.
(vi) Diversity of generation supply.
(vii) Whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective. Exceeding the renewable energy resources and energy waste reduction goal in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001, by a utility shall not, in and of itself, be grounds for determining that the proposed levels of peak load reduction, renewable energy, and energy waste reduction are not reasonable and cost effective.
(b) To the extent practicable, the construction or investment in a new or existing capacity resource in this state is completed using a workforce composed of residents of this state as determined by the commission. This subdivision does not apply to a capacity resource that is located in a county that lies on the border with another state.
(c) The plan meets the requirements of subsection (5).

Sections 6t(9) and 6t(10) address circumstances where the Commission rejects an IRP, and they provide for additional proceedings if this occurs:

> (9) If the commission denies a utility's integrated resource plan, the utility, within 60 days after the date of the final order denying the integrated resource plan, may submit revisions to the integrated resource plan to the commission for approval. The commission shall commence a new contested case hearing under chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287. Not later than 90 days after the date that the utility submits the revised integrated resource plan to the commission under this subsection, the commission shall issue an order approving or denying, with recommendations, the revised integrated resource plan if the revisions are not substantial or inconsistent with the original integrated resource plan filed under this section. If the revisions are substantial or inconsistent with the original integrated resource plan, the commission has up to 150 days to issue an order approving or denying, with recommendations, the revised integrated resource plan.
>
> (10) If the commission denies an electric utility's integrated resource plan, the electric utility may proceed with a proposed construction, purchase, investment, or power purchase agreement contained in the integrated resource plan without the assurances granted under this section.

Sections 6t(11) addresses the relevant cost approvals associated with this IRP:

> (11) In approving an integrated resource plan under this section, the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan. The costs for specifically identified investments, including the costs for facilities under subsection (12), included in an approved integrated resource plan that are commenced within 3 years after the commission's order approving the initial plan, amended plan, or plan review are considered reasonable and prudent for cost recovery purposes.

Section 6t(15) provides the Commission with discretion to approve a financial compensation mechanism for PPAs with unaffiliated electric generation providers:

> (15) For power purchase agreements that a utility enters into after the effective date of the amendatory act that added this section with an entity that is not affiliated with that utility, the commission shall consider and may

authorize a financial incentive for that utility that does not exceed the utility's weighted average cost of capital.

Finally, Sections 6t(17) and 6t (18) address recovery of costs associated with an IRP:

> (17) The commission shall include in an electric utility's retail rates all reasonable and prudent costs specified under subsections (11) and (12) that have been incurred to implement an integrated resource plan approved by the commission. The commission shall not disallow recovery of costs an electric utility incurs in implementing an approved integrated resource plan, if the costs do not exceed the costs approved by the commission under subsections (11) and (12). If the actual costs incurred by the electric utility exceed the costs approved by the commission, the electric utility has the burden of proving by a preponderance of the evidence that the costs are reasonable and prudent. The portion of the cost of a plant, facility, power purchase agreement, or other investment in a resource that meets a demonstrated need for capacity that exceeds the cost approved by the commission is presumed to have been incurred due to a lack of prudence. The commission may include any or all of the portion of the cost in excess of the cost approved by the commission if the commission finds by a preponderance of the evidence that the costs are reasonable and prudent. The commission shall disallow costs the commission finds have been incurred as the result of fraud, concealment, gross mismanagement, or lack of quality controls amounting to gross mismanagement. The commission shall also require refunds with interest to ratepayers of any of these costs already recovered through the electric utility's rates and charges. If the assumptions underlying an approved integrated resource plan materially change, or if the commission believes it is unlikely that a project or program will become commercially operational, an electric utility may request, or the commission on its own motion may initiate, a proceeding to review whether it is reasonable and prudent to complete an unfinished project or program included in an approved integrated resource plan. If the commission finds that completion of the project or program is no longer reasonable and prudent, the commission may modify or cancel approval of the project or program and unincurred costs in the electric utility's integrated resource plan. Except for costs the commission finds an electric utility has incurred as the result of fraud, concealment, gross mismanagement, or lack of quality controls amounting to gross mismanagement, if commission approval is modified or canceled, the commission shall not disallow reasonable and prudent costs already incurred or committed to by contract by an electric utility. Once the commission finds that completion of the project or program is no longer reasonable and prudent, the commission may limit future cost recovery to those costs that could not be reasonably avoided.

(18) The commission may allow financing interest cost recovery in an electric utility's base rates on construction work in progress for capital improvements approved under this section prior to the assets' being considered used and useful. Regardless of whether or not the commission authorizes base rate treatment for construction work in progress financing interest expense, an electric utility may recognize, accrue, and defer the allowance for funds used during construction.

In addition to the above regulatory requirements, in the settlement in the company's previous IRP, Consumers agreed to perform a detailed retirement analysis of Campbell 1 and 2,[4] and, under Paragraph 13 of the settlement, the parties agreed that this IRP must include:

a. Modeling of in-state and out-of-state wind;
b. A stochastic risk assessment;
c. Modeling of all optimized portfolios in all scenarios as part of the Risk Assessment Methodology;
d. Continued collaboration with METC and MISO on the implementation of the PCA including: (i) an analysis of the PCA's impact on the Zone 7 [capcity import limit] CIL; and (ii) an analysis of minimizing the impact on the Zone 7 CIL as well as investigating opportunities to increase the CIL and investigating transmission alternatives to improve market access;
e. Utilization of other mediums of communication to educate and collect feedback from interested stakeholders of the public;
f. Modeling of energy storage and solar resources either in isolation or as a combination and continued investigation into energy storage to potentially incorporate into future IRP modeling;
g. A list of all environmental regulations applicable to the utility fleet;
h. A description, to the extent practicable, of how a Michigan workforce will be utilized in the construction or investment in a new or existing capacity resource in this state;
i. Consideration of a distributed generation program, similar to Staff's Customer Distributed Generation Program proposed by Staff witness Meredith A. Hadala in this case;
j. A description of the demand for participation in customer-initiated renewable energy resources that are satisfying the Company's demand. The Company shall consider including the forecast dependent on actual data and trending;
k. A description of the transportation electrification and heating electrification impacts of the Company's demand forecast. The Company

[4] See June 7, 2019 order in Case No. U-20165, Exhibit A, ¶ 4.

shall consider including the forecast dependent upon actual data and trending;
l. A survey of current DR practices of other electric utilities, particularly an analysis of planning assumptions; whether limits are imposed on the amount of reserves that can be provided by DR; and quantifying the amount of DR as a percent of peak demand. The Company shall meet with representatives from ABATE to discuss the results of these studies prior to the filing of the Company's next IRP;
m. Results of a loss of load expectation study to assess the potential change in either the frequency or durations of curtailments and the role of DR in meeting peak demand. The study should reflect the impact of varying generation capacity mix scenarios, including the PCA and varying amounts of DR. The Company shall also monitor changing requirements for load modifying resources at MISO;
n. An assessment of ways to reduce excess capacity which may exist in the resource plan approved as part of this Settlement Agreement;
o. An assessment showing how the Company intends to meet peak demand during winter months with its resource portfolio in each of the projected plan years; and
p. An assessment of the impact of the FCM on the competitive bidding process.

III.

OVERVIEW OF THE RECORD

A. Consumers' Application

In its application, Consumers outlined the contents of the settlement agreement in the company's previous IRP as follows: (1) the approval of the company's proposed course of action (PCA) as modified by the settlement agreement, as the most reasonable and prudent course of action over the next five, 10, and 15 years; (2) an agreement by Consumers to update its IRP in June 2021; (3) preapproval of demand-side management costs through 2022; (4) approval to retire D.E. Karn (Karn) 1 and 2 in 2023; (5) the presentation of a retirement analysis of J. H. Campbell (Campbell) 1 and 2 in this IRP; (5) a competitive bidding process for acquiring future capacity and for determining PURPA avoided costs; (6) a 50/50 split of company and third-party ownership of supply-side resources; (7) the approval of a financial compensation mechanism (FCM) applied to power purchase agreements (PPAs) after January 2019; (8) continued collaboration with METC and the Midcontinent Independent System Operator, Inc. (MISO) on transmission; and (9) certain additional IRP modeling to be included in this case.[5]

The company describes its application in this case as a "refresh" of its 2018 IRP based on a reevaluation of capacity needs, regulatory and environmental compliance, and certain planning objectives. Consumers states that the PCA proposed here accelerates coal plant retirement without sacrificing reliability and that the plan will facilitate the company's goal of net-zero carbon emissions by 2040. Specifically, Consumers IRP and application include the following:

- The accelerated retirement of the Company's Karn 3 and 4 from May 31, 2031 to May 31, 2023; Campbell 1 and 2 from May 31, 2031 to May 31, 2025; and Campbell 3 from December 31, 2039 to May 31, 2025;

- The replacement of the capacity from the Karn and Campbell units (retiring units) with capacity from the New Covert Generating Facility (Covert) in 2023, and the purchase of Dearborn Industrial Generation (DIG), the Livingston Generating Station (Livingston), and the Kalamazoo River Generating Station (Kalamazoo) in 2025;[6]

- A request that the Commission approve the purchase of Covert for $815 million and the purchase of the CMS plants for $530 million;

- A request for preapproval of costs associated with energy waste reduction (EWR), demand response (DR), and conservation voltage reduction (CVR), including capital, operations and maintenance (O&M) expense, and financial incentive mechanisms (FIM) for programs implemented in the next three years;

- Requests for accounting approvals for: (1) regulatory asset treatment, with full return, to recover the remaining net book balances of the retiring units through their current design lives; (2) approval to defer employee retention

[5] Application, pp. 2-3.
[6] DIG, Kalamazoo, and Livingston are owned by Consumers' affiliate, CMS Enterprises. These plants are collectively referred to as the CMS plants in this PFD.

costs; and (3) approval to recover retirement transition costs through a regulatory asset;

- If necessary, a waiver of the asset transfer provisions of the Commission's Code of Conduct for the purchase of the CMS plants;

- Approval of modifications to Consumers' competitive procurement process, including allowing more flexibility in company ownership of supply-side resources;

- The continued use of the competitive procurement process for determining full avoided cost rates under the Public Utility Regulatory Policies Act (PURPA),[7] and the company's capacity needs for the purposes of PURPA. The company is also requesting modifications to its currently approved PURPA avoided cost construct and a continuation of the determination that the company does not have a PURPA capacity need so long as it is implementing the PCA and a competitive procurement approach;

- Approval of a revised financial compensation mechanism (FCM) for new or modified power purchase agreements (PPAs).[8]

Consumers states that its PCA "represents a fully integrated and optimized plan which requires approval in its entirety."[9] Further, Consumers avers that its application complies with the requirements under MCL 460.6t, the MIRPP, and the IRP filing requirements, including the company's presentation of a series of public outreach events and technical workshops for stakeholders.

Consumers' application states that "[its] PCA embodies a truly balanced plan across the Company's People, Planet, and Prosperity planning objectives and the Commission's planning objectives[,]"[10] averring that the PCA presented here includes greater reliability and more clean energy than its previously-approved IRP. Consumers highlights its comprehensive and robust risk assessment methodology, which fully

[7] Pub. L. 95–617, 92 Stat. 3117; 16 USC ch. 46 § 2601 et seq.
[8] Application, pp. 4-5.
[9] Id. at 5.
[10] Id. at 9.

supports the PCA, as well as the fact that execution of the PCA will allow Consumers to exit coal generation by 2025 and achieve net-zero carbon emissions by 2040.

B. Testimony

The parties to the proceeding presented the testimony of 77 witnesses as briefly outlined below. This review is intended to provide a summary of the subject matter of each witness's testimony, rather than a comprehensive recital. The testimony, exhibits, and arguments of the parties are discussed in greater detail as appropriate to address the disputed issues.

1. Consumers

Consumers presented the direct and rebuttal testimony of 26 witnesses.

Richard T. Blumenstock, Executive Director of Electric Planning for Consumers,[11] provided an overview of the company's case, including some details about the various proposals in the PCA.

Sara T. Walz, Manager of Integrated Resource Planning of the Electric Grid Integration Department for Consumers, testified regarding the processes and results of the company's modeling in support of the IRP and PCA.[12]

Robert J. Lee, Vice President in the Auctions and Competitive Bidding Practice for Charles River Associates, testified concerning Consumers' 2021 gas plant RFP. [13]

---

[11] Mr. Blumenstock's revised direct and rebuttal testimony are transcribed at 3 Tr 81-211. Cross examination of Mr. Blumenstock begins at 3 Tr 213 and ends at 3 Tr 245. Mr. Blumenstock's sur-surrebuttal testimony is transcribed at 8 Tr 3157-3162.

[12] Ms. Walz's revised direct testimony and revised rebuttal testimony are transcribed at 3 Tr 253-409. Cross examination of Ms. Walz can be found at 3 Tr 410-507.

[13] Mr. Lee's rebuttal testimony is transcribed at 3 Tr 513-528. Cross examination of Mr. Lee begins at 3 Tr 537 and ends at 4 Tr 644. A portion of Mr. Lee's cross examination is in the confidential record.

Keith G. Troyer, Director of Electric Grid Integration Contracts and Settlements in the Electric Supply Section of Consumers' Electric Grid Integration Department, provided an overview of the input assumptions in the Aurora modeling, Consumers' DR program, and Consumers' recommendations for competitive solicitations including the 2021 RFP. Mr. Troyers also provided details on the company's proposed FIM.[14]

Srikanth Maddipati, Treasurer and Vice President of Finance and Investor Relations for Consumers,[15] testified concerning the company's proposed FCM and on financial impact of securitization of the unrecovered book balance of the company's retiring plants.

Thomas P. Clark, Executive Director of Electric Supply for Consumers,[16] discussed the PCA and alternative plan, along with the company's assumptions about the current MISO market and future changes to the MISO market construct.

Jeffrey E. Battaglia, Director of Enterprise Project Management – Generation Transformation for Consumers, discussed the cost assumptions for supply-side resources and battery storage. Mr. Battaglia also provided an overview of new technologies and the proposed purchase of the CMS plants.[17]

Heather A. Breining, a Senior Engineering Technical Analyst III in Consumers' Environmental Services Department,[18] discussed the environmental regulations with

---

[14] Mr. Troyer's revised direct and revised rebuttal testimony are transcribed at 4 Tr 652-779. Cross examination of Mr. Troyer begins at 4 Tr 780 and continues at 5 Tr 914-936.

[15] Mr. Maddipati's direct and revised rebuttal testimony are transcribed at 5 Tr 943-1000. Cross and redirect examination of Mr. Maddipati are transcribed at 5 Tr 1001-1104.

[16] Mr. Clark's direct and rebuttal testimony are transcribed at 5 Tr 1109-1157. Cross examination of Mr. Clark can be found at 5 Tr 1159-1161.

[17] Mr. Battaglia's revised direct and rebuttal testimony are transcribed at 5 Tr 1169-1224. Cross examination of Mr. Battaglia begins at 5 Tr 1224 and continues at 6 Tr 1290-1330. A portion of Mr. Battaglia's cross examination is in the confidential record.

[18] Ms. Breining's revised direct testimony and revised rebuttal testimony are transcribed at 6 Tr 1336-1383. Cross examination and redirect of Ms. Breining is transcribed at 6 Tr 1385-1433.

which Consumers must comply, including compliance costs, timelines, and environmental justice concerns.

Emily A. McGraw, Executive Director of Demand Side Management for Consumers,[19] described the existing and proposed DR programs included in the company's IRP, including capital costs for these programs.

Heather M. Prentice, the Director of the Environmental Compliance, Risk Management & Governance section of Consumers' Environmental and Laboratory Services Department,[20] provided rebuttal addressing environmental permitting issues at the DIG plant.

Eugène M.J.A. Breuring, a Senior Rate Analyst III in the Planning, Budgeting and Analysis Section of Consumers' Rates and Regulation and Quality Department,[21] testified regarding the company's historical and projected electric deliveries and peak demand.

Jason R. Coker, a Principal Rate Analyst in the Revenue Requirements and Analysis Section of Consumers' Rates and Regulation Department,[22] testified regarding the fixed charge rate used in the IRP modeling. He also addressed rate impacts from the PCA, recovery of the remaining book balances of the retiring units, and treatment of costs for community transition plans.

---

[19] Ms. McGraw's revised direct and rebuttal testimony are transcribed at 6 Tr 1439-1468. Cross examination of Ms. McGraw can be found at 6 Tr 1469-1491.

[20] Ms. Prentice's confidential and public rebuttal testimony are transcribed at 6 Tr 1498-1503. Cross examination of Ms. Prentice is transcribed at 6 Tr 1504-1509. Portions of Ms. Prentice's cross examination are contained in the confidential record.

[21] Mr. Breuring's direct testimony is transcribed at 7 Tr 1571-1592.

[22] Mr. Coker's revised direct and revised rebuttal testimony are transcribed at 7 Tr 1595-1632.

Brian D. Gallaway, Executive Director of Fossil Fuel Supply in Consumers' Energy Supply Operations Department,[23] testified concerning current and projected fuel supply arrangements and costs.

Lakin H. Garth, Principal in the Energy Services sector of The Cadmus Group, Inc (Cadmus), discussed the approach and results of the 2021 Energy Waste Reduction Potential Study performed by Cadmus for 2021-2040.[24]

Teresa E. Hatcher, Executive Director of Electric Regulatory and Strategy for Electric Grid Integration for Consumers,[25] described the company's existing renewable generating facilities and its approach for meeting the renewable portfolio standard (RPS) going forward.

Matthew S. Henry, the Distribution Automation Technologies Team Lead in Consumers' Grid Modernization department, described the company's current and proposed conservation voltage reduction (CVR) program.[26]

Norman J. Kapala, Executive Director of Fossil and Renewable Generation for Consumers,[27] discussed capital and operations and maintenance (O&M) costs associated with the company's current fleet and how those costs are modeled in the IRP. He also detailed capital and O&M costs for the Covert plant and CMS plants.

Joseph T. Kelliher, the Principal of Joseph Kelliher Consulting, an energy regulatory consulting company,[28] provided rebuttal testimony regarding issues raised concerning the acquisition of the CMS plants.

[23] Mr. Gallaway's direct and rebuttal testimony are transcribed at 7 Tr 1635-1668.
[24] Mr. Garth's direct testimony is transcribed at 7 Tr 1671-1681.
[25] Ms. Hatcher's direct testimony is transcribed at 7 Tr 1684-1694.
[26] Mr. Henry's direct and rebuttal testimony are transcribed at 7 Tr 1697-1730.
[27] Mr. Kapala's revised direct and rebuttal testimony are transcribed at 7 Tr 1734-1821.
[28] Mr. Kelliher's rebuttal testimony is transcribed at 7 Tr 1824-1859.

Carolee Kvoriak, Executive Director of Tax for Consumers,[29] discussed the impacts of the production tax credit (PTC) for renewable energy on the company's PCA.

Steven Q. McLean, Director of Customer Experience Regulatory Strategy, Reporting and Quality in Consumers' Clean Energy Products Department,[30] testified regarding projected load reductions from the company's EWR programs and the impact on load from heating electrification.

Anna K. Munie, a Senior Engineering Technical Analyst in the Integrated Resource Planning Section of Consumers' Electric Grid Integration Department,[31] described the risk assessment methodology used by the company in developing the IRP.

Sarah R. Nielsen, Executive Director of Demand Side Management,[32] testified concerning current and projected resources for the company's voluntary green pricing (VGP) program and forecast of electric vehicle (EV) adoption in Consumers' service territory.

Benjamin T. Scott, a Senior Engineer Lead of High Voltage Distribution ("HVD") Planning West and Transmission within Consumers' Electric Grid Integration Department[33] discussed the company's evaluation of transmission alternatives, including transmission and distribution upgrades and cost assumptions used in the IRP modeling.

Teri L. VanSumeren, Executive Director of Energy Waste Reduction for Consumers,[34] discussed the benefits of the company's investments in EWR, DR, CVR, and VGP. She also testified regarding the inclusion of CVR as part of the EWR program.

---

[29] Ms. Kvoriak's direct and rebuttal testimony are transcribed at 7 Tr 1862-1874.
[30] Mr. McLean's direct and rebuttal testimony are transcribed at 7 Tr 1877-1901.
[31] Ms. Munie's revised direct and revised rebuttal testimony are transcribed at 7 Tr 1904-1946.
[32] Ms. Neilson's direct and rebuttal testimony are transcribed at 7 Tr 1949-1968.
[33] Mr. Scott's revised direct and rebuttal testimony is transcribed at 7 Tr 1971-2015.
[34] Ms. VanSumeren's direct and rebuttal testimony are transcribed at 7 Tr 2018-2033.

Nathan J. Washburn, Director of Distributed Energy Resources/Instrumentation and Controls Design for Consumers,[35] testified regarding the battery storage proposals in the company's IRP.

Kevin J. Watkins, a Senior Accounting Analyst III in Consumers' Corporate Property Accounting Department[36] projected the unrecovered book balances for Karn 3 and 4 and Campbell through 3. In addition, Mr. Watkins provided the projected decommissioning and ash disposal costs for the Karn and Campbell units.

2. Commission Staff

Staff presented the testimony of 18 witnesses.

Paul A. Proudfoot, Director of the Energy Resources Division,[37] provided an overview of Staff's case and primary recommendations for this and future IRPs.

Kayla R. Gibbs, a Departmental Analyst in the Resource Optimization and Certification Section of the Energy Resources Division,[38] discussed Staff's review of Consumers' application with respect to the IRP filing requirements, stakeholder engagement, and reporting requirements.

Megan Kolioupoulos, a Departmental Analyst in the Resource Adequacy and Retail Choice Section of the Energy Resources Division, [39] discussed Executive Directive 2020-10 and highlighted environmental justice and other environmental considerations presented by Consumers and in EGLE's Advisory Opinion.

[35] Mr. Washburn's direct and rebuttal testimony are transcribed at 7 Tr 2036-2064.
[36] Mr. Watkin's direct testimony is transcribed at 7 Tr 2067-2071.
[37] Mr. Proudfoot's testimony is transcribed at 8 Tr 3389-3416.
[38] Ms. Gibbs testimony is transcribed at 8 Tr 3513-3532.
[39] Ms. Kolioupoulos' testimony is transcribed at 8 Tr 3592-3604.

Anna N. N. Schiller, a Public Utilities Engineer in the Resource Adequacy and Retail Choice Section of the Energy Resources Division,[40] presented Staff's evaluation of Consumers' forecasts for load, market price, capacity, fuel, and electric vehicle (EV) adoption used in developing the IRP.

Matthew A. Champion, a Public Utilities Engineer in the Resource Optimization and Certification Section of the Energy Resources Division,[41] discussed Consumers' modeling assumptions for new and existing fossil generation units.

Cody S. Matthews, a Public Utilities Engineer Specialist in the Renewable Energy Section of the Energy Resources Division,[42] presented Staff's review and recommendations concerning Consumers' renewable energy modeling assumptions and distributed energy resources including storage.

Jonathan J. DeCooman, a Public Utilities Engineer in the Resource Optimization and Certification Section of the Energy Resources Division,[43] testified regarding Consumers' compliance with the Michigan Integrated Resource Planning Parameters (MIRPP) modeling scenarios and sensitivities. Mr. DeCooman also discussed the company's Campbell 3 retirement analysis.

Zachary C. Heidemann, a Public Utilities Engineer in the Resource Optimization and Certification Section of the Energy Resources Division,[44] reviewed Consumers' capacity sufficiency analysis and risk assessment, and he discussed the findings of some modeling runs completed by Staff in Aurora.

[40] Ms. Schiller's testimony is transcribed at 8 Tr 3671-3681.
[41] Mr. Champion's testimony is transcribed at 8 Tr 3439-3446.
[42] Mr. Matthews' testimony is transcribed at 8 Tr 3619-3628.
[43] Mr. DeCooman's testimony is transcribed at 8 Tr 3449-3475.
[44] Mr. Heidemann's revised direct testimony is transcribed at 8 Tr 3564-3589.

Katie J. Smith, an Economic Specialist in the Energy Waste Reduction Section of the Energy Resources Division,[45] provided Staff's recommendations concerning the company's EWR targets presented in this case.

Roger A. Doherty, an Engineer in the Resource Adequacy and Retail Choice Section of the Energy Resources Division,[46] provided testimony about Consumers' DR programs, the company's assumptions about capacity import and export limits, and resource adequacy.

Tayler J. Becker, a Public Utilities Engineering Specialist in the Commission's Electric Operations Section,[47] testified on Consumers request for CVR cost approvals and on the alignment of distribution planning with IRPs.

Robert F. Nichols, the Manager of the Revenue Requirements Section of the Regulated Energy Division,[48] testified regarding Consumers' request for pre-approval of an acquisition premium for its proposed gas plant purchases to be included in rates, accounting treatment for the unrecovered book value and decommissioning costs for the retiring units, and Consumers' proposed FCM.

Kirk L. Forbes, a Manager in the Analytical Support Section in the Regulated Energy Division,[49] discussed Staff's position on the Code of Conduct as it relates to Consumers' proposed affiliate transaction with CMS Enterprises to purchase the CMS plants.

---

[45] Ms. Smith's direct and rebuttal testimony are transcribed at 8 Tr 3705-3715.
[46] Mr. Doherty's testimony is transcribed at 8 Tr 3478-3500.
[47] Mr. Becker's testimony is transcribed at 8 Tr 3419-3436.
[48] Mr. Nichols' testimony is transcribed at 8 Tr 3632-3665. Portions of Mr. Nichols' testimony and several of his exhibits are confidential pursuant to the protective order.
[49] Mr. Forbes' testimony is transcribed at 8 Tr 3503-33510.

Merideth A. Hadala, a Departmental Analyst in the Resource Optimization and Certification Section,[50] testified regarding Consumers' proposed updates to the company's PURPA avoided cost calculation and other PURPA issues, along with the alignment between capacity need determinations and IRP filings.

Naomi J. Simpson, a Public Utilities Engineer in the Resource Optimization and Certification Section of the Energy Resources Division,[51] reviewed Consumers' transmission analysis under MCL 460.6t and Section XII of the IRP filing requirements.

Jesse J. Harlow, Manager of the Resource Adequacy and Retail Choice Section of the Energy Resources Division,[52] discussed Consumers' recommended changes to competitive procurement of supply-side resources and its RFP for the proposed gas plant purchases of the Covert and the CMS plants.

Kevin S. Krause,[53] a Gas Cost of Service Specialist within the Regulated Energy Division, Rates and Tariff Section, described potential federal legislation that, if enacted, could affect Consumers' IRP.

Anne T. Armstrong, Director of the Customer Assistance Division,[54] presented rebuttal testimony on the Commission's customer outreach and engagement programs, low-income and customer assistance programs, in response to the UCC.

---

[50] Ms. Hadala's testimony is transcribed at 8 Tr 3535-3546.
[51] Ms. Simpson's testimony is transcribed at 8 Tr 3684-3702.
[52] Mr. Harlow's testimony is transcribed at 8 Tr 3549-3561.
[53] Mr. Krause's direct testimony is transcribed at 8 Tr 3607-3616.
[54] Ms. Armstrong's rebuttal testimony is transcribed at 8 Tr 3718-3735.

3. Attorney General

The Attorney General presented the testimony of **David E. Dismukes**, a Consulting Economist with the Acadian Consulting Group.[55] Dr. Dismukes reviewed Consumers' IRP and provided several recommendations on the proposed PCA.

4. Michigan Environmental Council, Natural Resources Defense Council, Sierra Club

MNS presented the testimony of six witnesses.

Douglas B. Jester, a Partner of 5 Lakes Energy LLC,[56] testified regarding environmental compliance cost risks at the DIG plant, zonal the resource credits (ZRCs) that should be applied to solar generation, and Consumers' proposed solar capacity acquisitions. Mr. Jester also addressed stranded cost recovery for the company's retiring units and Consumers' proposal to revise the FIM.

Tyler Comings, a Senior Researcher at Applied Economics Clinic,[57] evaluated Consumers' decision to purchase the CMS plants and discussed the risks associated with purchasing those plants. Mr. Comings also presented two alternate PCAs, and he discussed transition planning for the Karn and Campbell retirements.

George W. Evans, the President of Evans Power Consulting, Inc.,[58] discussed Consumers' modeling approach in developing the IRP and PCA. Mr. Evans also described his approach to developing two alternative PCAs.

[55] Dr. Dismukes direct testimony is transcribed at 7 Tr 2077-2132.
[56] Mr. Jester's direct and rebuttal testimony are transcribed at 7 Tr 2577-2643. Mr. Jester's cross examination and redirect can be found at 7 Tr 2644-2674. Portions of Mr. Jester's testimony are contained in the confidential record.
[57] Mr. Comings direct and rebuttal testimony are transcribed at 8 Tr 2947-3033. Portions of Mr. Comings testimony are contained in the confidential record.
[58] Mr. Evans' direct and rebuttal testimony are transcribed at 8 Tr 3038-3063. Parts of Mr. Evans' testimony are confidential.

Chris Neme, a Principal of Energy Futures Group,[59] discussed Consumers' proposals with respect to EWR and DR in its IRP.

P. Jay Caspary, Vice President at Grid Strategies, LLC,[60] discussed the importance of transmission planning in IRP development and discussed concerns with the way that the company addressed transmission.

Casey A. Roberts, a Senior Attorney at the Sierra Club,[61] provided rebuttal testimony addressing potential revisions to the SEEG rule and application to the retirement of Campbell 3.

5. Clean Energy Organizations

The CEOs provided the testimony of eight witnesses.

Joseph M. Daniel, a Senior Energy Analyst and Manager, Electricity Markets for the Union of Concerned Scientists,[62] testified regarding Consumers' use of the "must run" constraint for coal units in the IRP modeling.

Chelsea Hotaling, a Consultant at Energy Futures Group,[63] performed Aurora modeling for the CEO's, evaluating the impacts of alternative solar distributed generation options.

William D. Kenworthy, Regulatory Director, Midwest, for Vote Solar,[64] made recommendations regarding the integration of the IRP with distribution system planning and distributed generation (DG) resources.

---

[59] Mr. Neme's direct testimony can be found at 8 Tr 3067-3095. A portion of Mr. Neme's testimony is confidential.
[60] Mr. Caspary's direct testimony is transcribed at 8 Tr 3099-3124.
[61] Ms. Roberts' rebuttal testimony is transcribed at 8 Tr 3128-3137.
[62] Mr. Daniel's direct testimony is transcribed at 7 Tr 2288-2298.
[63] Ms. Hotaling's direct testimony is transcribed at 7 Tr 2301-2303.
[64] Mr. Kenworthy's direct testimony is transcribed at 7 Tr 2307-2335.

Alison Waske Sutter, the Sustainability and Performance Management Officer at the City of Grand Rapids,[65] discussed Consumers' IRP from the perspective of Grand Rapids, considering the City's sustainability and resilience goals.

Elena Krieger, Ph.D., the Director of Research at Physicians, Scientists, and Engineers for Healthy Energy,[66] provided a framework for evaluating the public health and energy equity impacts of Consumers' IRP and assessed the impacts of the company's plan on health and equity.

Kelsey Bilsback, a senior scientist at Physicians, Scientists, and Engineers for Healthy Energy,[67] quantified the public health and equity dimensions of coal, gas, and biomass generation in Consumers service territory, calculating the total emissions, rate of emissions, and fine particulate matter ($PM_{2.5}$) health effects for each plant, including those the company proposes to purchase.

Boris Lukanov, a Senior Scientist at Physicians, Scientists, and Engineers for Healthy Energy,[68] provided a framework for evaluating the energy cost burden in Consumers' service territory; he explained why energy cost impacts should be considered as part of the IRP, and he discussed ways to increase energy affordability for Consumers' customers.

Synia Gant-Jordan, owner-operator of Samaria J's Salon in Grand Rapids,[69] testified regarding the impacts of high energy costs on low-income and communities of color in the Grand Rapids area and the need for investment in community solar.

[65] Ms. Waske Sutter's direct testimony is transcribed at 7 Tr 2338-2358.
[66] Dr. Krieger's revised direct testimony is transcribed at 7 Tr 2361-2390.
[67] Ms. Bilsback's direst and rebuttal testimony are transcribed at 7 Tr 2394-2429.
[68] Mr. Lukanov's direct testimony is transcribed at 7 Tr 2432-2449.
[69] Ms. Gant-Jordan's testimony is transcribed at 7 Tr 2452-2454.

6. ABATE

ABATE presented the testimony of four witnesses.

James R. Dauphinais, a consultant in the field of public utility regulation and a Managing Principal with Brubaker & Associates, evaluated Consumers' PCA and Alternative Plan. Mr. Dauphinais also presented ABATE's alternative PCA, and he addressed Consumers' proposal to own 50% of new supply-side resources.[70]

Brian C. Andrews, a consultant in the field of public utility regulation and an Associate with Brubaker & Associates, Inc.,[71] addressed the revenue requirements of Consumers' PCA and Alternative Plan, as well as ABATE's alternate PCA.

Jessica A. York, a consultant in the field of public utility regulation and an Associate with Brubaker & Associates, Inc.,[72] addressed: (1) Consumers' proposal for recovery of the remaining book balance of the retiring plants; (2) the acquisition premium associated with the company's proposed purchase of the CMS plants; and (3) Consumers' request for a financial incentive for EWR and DR programs.

Christopher C. Walters, a consultant in the field of public utility regulation and an Associate with Brubaker & Associates, Inc.,[73] addressed Consumers' proposed changes to the FCM for PPAs and made recommendations for recovery of the net book value of the retiring units.

7. Energy Innovation Business Council, Institute for Energy Innovation, Clean Grid Alliance

EIBC/IEI/CGA presented the testimony of three witnesses.

[70] Mr. Dauphinais' direct and rebuttal testimony are transcribed at 7 Tr 2744-2783.
[71] Mr. Andrews' revised direct testimony is transcribed at 7 Tr 2789-2803.
[72] Ms. York's testimony is transcribed at 7 Tr 2811-2840.
[73] Mr. Walters' direct testimony is transcribed at 7 Tr 2845-2864.

Dr. Laura S. Sherman, President of the Michigan Energy Innovation Business Council and the Institute for Energy Innovation,[74] discussed the modeling of combined heat and power (CHP) in the IRP, along with other issues concerning DG (i.e., Standard Offer Tariff revisions, PURPA, resource ownership, competitive procurement, and the FCM). Her surrebuttal testimony addressed Consumers' proposed changes to its battery storage program presented in the company's rebuttal.

Edward Burgess, a Senior Director at Strategen Consulting,[75] evaluated Consumers' IRP and PCA, focusing particularly on energy storage and the modeling of that resource. Mr. Burgess also discussed the company's 2021 RFP.

Sean R. Brady, Senior Counsel and Regional Policy Manager – East for Clean Grid Alliance,[76] reviewed Consumers IRP and PCA and recommended modifications related to the modeling of renewables and battery storage as a replacement for the procurement of new gas units.

8. Energy Michigan

Energy Michigan sponsored the testimony of **Alexander J. Zakem**, an independent consultant on utility matters.[77] Mr. Zakem addressed Consumers' proposal to purchase the CMS plants. Mr. Zakem also discussed the company's proposal to revise and expand the FCM for PPAs and the calculation of the local clearing requirement (LCR) used in the IRP modeling.

9. Hemlock Semiconductor

HSC provided the direct and rebuttal testimony of two witnesses.

---

[74] Dr. Sherman's direct, rebuttal, and surrebuttal testimony are transcribed at 8 Tr 3206-3285.
[75] Mr. Burgess's direct testimony is transcribed at 8 Tr 3290-3347.
[76] Mr. Brady's direct and rebuttal testimony are transcribed at 8 Tr 3351-3384.
[77] Mr. Zakem's direct and rebuttal testimony are transcribed at 8 Tr 3165-3201.

Phillip M. Rausch, a Solar Commercial Manager for HSC,[78] made recommendations with respect to Consumers' proposed solar procurement in the PCA. His rebuttal testimony addressed securitization of unrecovered balances for retiring units.

Thomas M. Feldman, a Director at Atrium Economics, LLC,[79] filed rebuttal in response to proposals regarding securitization of unrecovered booked balances for retiring units.

10. Great Lakes Renewable Energy Association

GLREA presented the testimony of two witnesses.

John Richter, Board member and Senior Policy Analyst for GLREA,[80] provided background information on the health and environmental impacts, as well as cost risks, associated with fossil generation in the company's PCA. He also discussed the company's modeling of solar energy, and he presented an alternative PCA that relies more on renewable energy. Mr. Richter also addressed cost recovery for the retiring plants in the company's PCA, changes to Consumers' PURPA construct, new asset ownership issues, and the proposed FCM.

Robert Rafson, a member of GLREA Regulatory Affairs Committee, the owner of Chart House Energy, LLC and a Customer of Consumers,[81] testified regarding an alternative PCA that does not include the purchase of any gas plants. He also addressed EV adoption assumptions and low-income energy cost issues.

---

[78] Mr. Rausch's direct and rebuttal testimony are transcribed at 7 Tr 2208-2235.
[79] Mr. Feldman's rebuttal testimony is transcribed at 7 Tr 2239-2260.
[80] Mr. Richter's revised direct testimony is transcribed at 8 Tr 3740-3809.
[81] Mr. Rafson's revised direct testimony is transcribed at 8 Tr 3812-3851.

11. Wolverine Power Supply Cooperative

WPSC provided the testimony of **Thomas King Jr**., Director of Regulation and Policy for WPSC.[82] Mr. King testified regarding the impacts of Consumers' proposed early retirement of Campbell 3.

12. Michigan Electric Transmission Company

METC sponsored the testimony of **Charles Marshall**, Vice President of Planning for ITC Holdings Corp, the parent company of METC.[83] Mr. Marshall discussed the role of transmission in resource planning. He also testified regarding the impact of the PCA on the transmission system, Consumers' use of the capacity import limit (CIL) in the PCA, and the ways that transmission planning can support the company's clean energy goals.

13. Biomass Plants

The BMPs presented the testimony of **Richard A. Polich**, a Managing Director with GDS Associates, Inc.[84] Mr. Polich testified regarding the ongoing viability of the BMPs as potential generation resources for Consumers. He also discussed some of the assumptions Consumers used in modeling solar energy.

14. Citizens Utility Board

CUB sponsored the testimony of **David L. Gard**, a Senior Consultant with 5 Lakes Energy LLC.[85] Mr. Gard discussed residential DR potential in Consumers' service territory.

[82] Mr. King's direct and rebuttal testimony are transcribed at 7 Tr 2263-2283.
[83] Mr. Marshall's revised direct testimony is transcribed at 7 Tr 2546-2570.
[84] Mr. Polich's revised direct testimony and rebuttal testimony are transcribed at 7 Tr 2679-2735.
[85] Mr. Gard's testimony is transcribed at 7 Tr 2458-2470.

15. Urban Core Collective

UCC sponsored the testimony of **Sergio Cira-Reyes**, the Climate Justice Catalyst at Urban Core Collective, a non-profit organization based in Grand Rapids.[86] Mr. Cira-Reyes discussed energy concerns of low-income customers and communities of color, cost recovery associated with the proposed unit retirements in the IRP, the company's proposed acquisition of gas units, Consumers' proposals with respect to solar and EWR, and Consumers' public engagement efforts.

IV.

POSITIONS OF THE PARTIES

A. Consumers Energy

Consumers contends that its proposed PCA represents the most reasonable and prudent means of meeting the company's energy and capacity needs over the next five, 10, and 15 years. Consumers maintains that the plan provides for reliability, while at the same time it accelerates the company's transition to clean energy with the elimination of coal generation and the expansion of batteries, solar energy, and demand-,side resources beyond the company's 2018 IRP.

Consumers discusses the benefits of its IRP including $628 million in customer savings over the life of the plan, long-term supply reliability, a significant reduction in reliance on the market, increased demand-side resources and renewable energy, reduced carbon and other emissions, and financial stability for the company. Consumers notes that Staff and other parties to this proceeding recommend changes to the IRP. Nevertheless, the company urges the Commission to approve its IRP without any

[86] Mr. Cira-Reyes' direct and rebuttal testimony are transcribed at 7 Tr 2473-2543.

alterations, noting that "[m]odification to or rejection of a proposal made in the PCA impacts the PCA's viability and the Company's willingness to execute on the remaining portions of the PCA that are not modified or rejected. Thus, the Company reserves the right to abandon or amend its PCA if the Commission rejects any of the Company's proposals presented in this IRP."[87] Consumers adds that it is committed to filing an IRP every three years to address the uncertainties after the first three years of the plan.

Consistent with its application, testimony, and exhibits, Consumers requests that the Commission: (1) approve the company's PCA, including its battery deployment program, as the most reasonable means to meet the company's energy and capacity requirements over the IRP period; (2) approve the purchase of Covert and the CMS units in 2023 and 2025; (3) approve proposed EWR, DR, and CVR cost for programs commencing within the next three years; (4) find that the selection of the CMS units through a competitive solicitation complies with the Code of Conduct or, in the alternative, approve a waiver of the asset transfer provisions of the code; (5) approve the company's proposal to recover the net book balances of the retiring units through regulatory asset treatment, with full return, over the design lives of those units; (6) approve the company's proposals to defer employee retention costs related to the retiring units and recover retirement transition costs through a regulatory asset; (7) approve Consumers' proposed competitive procurement process and the use of that competitive procurement process for determining PURPA avoided costs rates and determining the company's capacity position; (8) find that the company has no PURPA capacity need so long as the company

[87] Consumers brief, pp. 6-7.

is implementing the PCA, with the competitive procurement process proposed here; and (9) approve the company's modified FCM.

B. <u>Staff</u>

Staff recommends three major changes to Consumers' PCA. First, while Staff agrees that the company's decisions to accelerate the retirement of Karn 3 and 4 and Campbell 1 and 2 are well supported, Staff argues that Consumers' modeling of Campbell 3 was insufficient to confirm that a 2025 retirement date is reasonable. Staff therefore proposes that the company undertake additional modeling and present the results as an update to this case or in a future IRP. Staff emphasizes that it is not suggesting that Campbell 3 continue to run until 2039, only that the company should evaluate additional retirement dates between 2025 and 2039.

Next, Staff recommends that Consumers either remove the purchase of the CMS plants from its PCA, or that the company renegotiate the price to eliminate the acquisition premium from the cost. Staff argues that Consumers' 2021 RFP was overly restrictive and led to an inflated bid from CMS, noting that additional modeling of the Campbell 3 retirement may demonstrate that the acquisition of the CMS plants is unnecessary.

Finally, Staff maintains that the request for an acquisition premium for the purchase of the CMS plants is unprecedented and that the company did not justify a waiver of the Code of Conduct. Accordingly, Staff recommends that Commission only approve recovery of the book value of the CMS plants, if it finds that the purchase of the plants is reasonable and prudent.

Staff makes additional recommendations with respect to Consumers' requests for cost recovery. In sum, Staff recommends that the Commission preapprove capital costs for the acquisition of Covert, and for DR and CVR. However, Staff maintains that the recovery of O&M costs and financial incentives for these programs should not be approved as part of the IRP. Nevertheless, except for CVR, Staff asserts that projected financial incentives for EWR and DR should be included as costs in the modeling of these resources.

Staff opposes the award of any FCM in this IRP, arguing that the company has not demonstrated that PPAs have a negative impact on the company's financials. If the Commission were to find an FCM reasonable, Staff recommends that the incentive be limited (i.e., exclusive of PPAs entered into or modified for RPS compliance, PPAs for the company's VGP programs, or PURPA PPA contracts) and that the incentive mechanism be based on the same FCM computation approved in Consumers' previous IRP, or the mechanism approved in Case No. U-20713, DTE Electric's recent VGP case.

With respect to the unrecovered costs for the Karn and Campbell units, Staff states that it supports the company's base proposal to recover the net book value of the retiring units through a regulatory asset. Concerning the company's request to earn a full return on the value of the retired units, Staff notes that the Commission could approve the company's request; however, Staff presented a number of alternatives including no return on the net book value of the assets, an alternative rate return (e.g., short- or long-term debt cost rate, or some other rate) or a return contingent on securitization. In addition, Staff suggests that the Commission could consider different amortization periods, noting that the Commission could approve any number of rates or return periods.

Staff notes that Consumers also proposes regulatory asset treatment for projected decommissioning and ash disposal costs. Staff recommended an alternative, namely approval to record a regulatory asset for actual decommissioning costs, with a return on, subject to review and approval in a subsequent rate case. According to Staff, Consumers found this approach reasonable. Staff did not support the company's request for regulatory asset treatment for employee retention costs or transition costs, contending that these costs are uncertain at this point and should be reviewed in a rate case.

Turing to the company's proposals with respect to competitive procurement and PURPA, Staff recommends that the Commission adopt the company's proposal to own at least 50% of resources in each round of RFPs, provided that the company continue to undertake annual solicitations and that the company true up amounts in subsequent solicitation rounds so that the 50/50 division between company-owned and third-party ownership of assets is maintained. Staff also recommends that before shortening the PPA term from 25 years to 15 years, Consumers should present an analysis of the effect of this proposal on PPA costs.

Staff supported many of the company's proposals with respect to PURPA avoided costs, determination of capacity need, and other terms and conditions of PURPA agreements. However, Staff advocates that: (1) QFs up to 100 kW_{ac} should receive full avoided cost rates without the need for a PURPA standard offer contract; (2) all QFs with expiring contracts should be offered renewed contracts at full avoided cost rates based on the most recent solicitation; and (3) Consumers should implement a standard offer energy-only contract for QFs between 100 kW_{ac} and at or below 5 MW_{ac}, and Consumers develop a process to acquire the capacity from those QFs with energy-only contracts prior to issuing a competitive solicitation.

Finally, Staff made several recommendations for improving the company's next IRP filing including: (1) Consumers should undertake a more robust risk assessment in its modeling; (2) the company should keep the information on stakeholder meetings in advance of the IRP filing available on its website until the Commission issues a final order; (3) Consumers should involve community members in transition planning in areas where the company is planning plant retirements; (4) Consumers should consider the recommendations made by UCC witness Cira-Reyes regarding outreach and education efforts to low-income communities and communities of color in the context of the MIPowerGrid, Customer Education and Outreach, and Energy Affordability workgroups; and (5) the Commission should consider the potential impacts of pending federal legislation in evaluating Consumers' IRP and PCA.

C. Attorney General

The Attorney General supports the early closure of the Karn and Campbell units; however, she disagrees with Consumers' proposal to recover the remaining book balance of the retiring units through traditional ratemaking. Instead, the Attorney General recommends that the Commission direct the company to make a separate filing addressing cost recovery closer to the dates the units will retire. She adds that the company should include a proposal for securitization as part of that filing.

Recognizing that some replacement capacity will be required to address shortfalls after unit retirement, the Attorney General nevertheless recommends that the Commission limit cost recovery for the CMS plants to the net book value of these plants and deny the company's request to recover an acquisition premium.

Although the Attorney General does not oppose the continuation of the EWR, DR, and CVR programs as proposed in the IRP, she nevertheless has concerns about the benefits of these programs compared to their costs and urges the Commission to scrutinize non-program costs and financial incentives associated with these programs to ensure cost-effectiveness.

Finally, the Attorney General urges the Commission to reject Consumers' proposal to own "at least" 50% of new capacity resulting from competitive solicitations. Further, the Attorney General recommends that the Commission reject the company's request for an FCM for PPAs. The Attorney General contends that the company failed to justify the need for an FCM, but if the Commission finds that an FCM is reasonable, it should nevertheless reject Consumers' proposed changes to the mechanism.

D. Michigan Environmental Council, Natural Resources Defense Council, Sierra Club

MNS points out that none of the parties to this proceeding oppose the early retirement of Karn 3 and 4 in 2023 or the early retirement of Campbell 1 and 2 in 2025, and therefore the Commission should approve these proposals. And, although some parties question the economics and reliability implications of closing Campbell 3 in 2025, MNS maintains that early retirement of this unit, as the company proposes, is fully supported by the record and should also be approved. MNS contends that early retirement of Campbell 3 would be more economical and would provide significant climate and health benefits compared to keeping the unit running beyond 2025.

MNS supports the acquisition of Covert in 2023, but it opposes the purchase of some, or all, of the CMS plants. According to MNS, their modeling demonstrates that Consumers can meet reliability requirements with short term capacity purchases and the acquisition of Livingston in 2025. Alternatively, MNS suggests that capacity from Campbell 3 can be replaced by additional solar and storage. MNS argues that, among other things, Consumers' RFP that resulted in the selection of the plants was seriously flawed, and there are significant costs and environmental risks associated with the purchase of Kalamazoo and DIG.

Next, MNS contend that Consumers' 500 MW per year cap on solar acquisitions is arbitrary, pointing to the large number of solar projects in the MISO interconnection queue as well as previous responses to the company's RFP solicitations. MNS further note that Consumers' use of an incorrect effective load carrying capability (ELCC) in its solar modeling resulted in the selection of less solar energy.

MNS agree with Staff that Consumers should incorporate a 2% target for EWR in its IRP, noting that the company has included this savings amount in its EWR plan. MNS contends that Consumers' modeling of EWR was flawed because the inputs for energy efficiency do not include avoided transmission and distribution (T&D) costs; the company did not include the NPV of expected savings after 2040, and the company calculated savings based on average, rather than marginal, line losses. According to MNS, correcting these errors in modeling EWR would result in $200 million more in savings from energy efficiency compared to Consumers' base case.

Similar to their criticism of Consumers' EWR modeling, MNS contend that the company undervalues DR by failing to include avoided T&D costs and by using average rather than marginal line losses, thus assuming that DR benefits are limited to generation capacity. MNS recommend that in future IRPs, Consumers should model DR more accurately.

Next, MNS argue that Consumers' transmission analysis does not comport with the requirements under Section 6t, the Commission's filing requirements or the settlement agreement in the company's previous IRP. According to MNS, Consumers relied on an outdated estimate of the CIL, and it failed to evaluate options for increasing CIL. In addition, MNS assert that Consumers did not evaluate or consider PPAs to import power.

Finally, MNS recommend that the Commission authorize Consumers to establish a regulatory asset for the remaining net book balance of the retiring units, but it should also require the company to securitize these costs. MNS also urge the Commission to deny Consumers' request to alter the FCM and to deny the company's request to change its procedures for acquiring solar energy. MNS recommend that the Commission approve Consumers' battery storage proposal presented in rebuttal, and that the Commission direct the company to release transparent community transition plans for the Karn and Campbell retirements.

E. Clean Energy Organizations

The CEOs criticize Consumers' public health and environmental justice (EJ) modeling as inadequate, recommending that instead the Commission adopt the more robust, quantitative analyses presented by the CEOs' expert witnesses. Based on the CEO's analysis, the closure of the Karn and Campbell units would result in significant positive health and EJ impacts to nearby communities. The CEOs note that Campbell 3 should be prioritized for retirement because that unit has the highest total adverse health impacts of the gas and coal plants in the company's fleet.

The CEOs argue that Consumers' proposal to purchase the CMS units is not supported by an EJ analysis, noting that DIG, in particular, has higher public health impacts than even the company's coal-fired units. Citing testimony by Staff and intervenor witnesses, the CEOs further contend that Consumers' RFP was significantly limited and as a result removed other viable, cleaner technologies from consideration.

Next, the CEOs argue that Consumers' proposal to recover the net book value of the retiring units through regulatory asset treatment is unjust and unreasonable, contending that the recovery of these costs will further burden the company's most vulnerable customers. The CEOs urge the Commission to adopt the recommendation to decide on cost recovery for the retiring units in another proceeding where securitization of these costs can be evaluated.

Noting that the Commission has found that the modeling of DG is an essential part of IRP development, the CEOs maintain that the company's modeling of behind-the-meter generating (BTMG) resources was deficient because in most of the scenarios, BTMG was screened out of the analyses, which only evaluated distribution and transmission connected solar generation. Even where BTMG resources were included, these resources were not optimized as part of the modeling. The CEOs further observe that Consumers failed to differentiate the costs of distribution-connected solar and utility-scale transmission-connected solar, thus the modeling does not necessarily select the most economical resource. The CEOs assert that Consumers fails to recognize the value of DG to the company and its customers, and they recommend that the Commission approve a pilot program to incentivize BTMG for low-income customers. Finally, the CEOs criticize Consumers for using nationally reported costs for solar, rather than relying on the company's most recent solicitation. In sum, the CEOs recommend that Consumers be directed to appropriately model BTMG as a supply-side resource in the company's next IRP.

Acknowledging that Consumers' efforts to incorporate distribution system planning and benefits into the IRP are improved, particularly with respect to battery storage, the CEOs nevertheless maintain that Consumers could enhance the integration of generation, transmission, and distribution planning by taking a more detailed approach to load forecasting and include possibilities for deferral of distribution upgrades through non-wires alternatives.

Next, the CEOs recommend that the Commission deny Consumers' request for a FCM for PPAs. The CEOs note that per the settlement agreement in Consumers' previous IRP, the parties agreed that the FCM could be discontinued in this case, for future contracts, if the company failed to show that the mechanism reduces costs for customers. The CEOs maintain that the company failed to show that the previously-approved FCM provided benefits to customers, nor did it show that the modified FCM the company proposes will reduce customer costs.

Lastly, the CEOs urge the Commission to require Consumers to turn the must-run designation for coal units to "off" in its modeling of all cases and scenarios in the company's next IRP. The CEOs contend that although the Commission has accepted the must-run designation in the past, market dynamics have changed significantly as the energy transition moves forward.

F. Association of Businesses Advocating Tariff Equity

ABATE argues that Consumers' PCA does not ensure resource adequacy, as defined by the PRMR, because in 2025, the company proposes to retire one unit

(Campbell 3), located in MISO Zone 7, and replace it with three other units (CMS plants) that are likewise part of Zone 7, resulting in a net loss of capacity in the zone. According to ABATE, Consumers incorrectly assumes that because the company will have sufficient capacity to serve its own peak load it will not experience a loss of load event. ABATE maintains that even if Consumers has sufficient capacity to serve its own customers, if Zone 7, the MISO subregion, or MISO as a whole, does not have sufficient capacity to serve demand there is still the potential for a loss of load event. ABATE asserts that Consumers' CSA does not capture the fact that electricity supply and demand must be considered in this wider context and therefore the PCA and Alternative Plan do not accurately address reliability. ABATE also questions assertions by MNS that reliability can be addressed through additional solar development, PPAs, and accelerated battery storage, describing MNS's proposals as "unreasonable [and] speculative" claims about the future.

Next, ABATE argues that Consumers' economic comparison between its PCA and Alternate Plan is deficient. According to ABATE, Consumers only compared the retirement of Campbell 3 in 2025 (per the PCA) to running Campbell 3 until 2039, without evaluating other retirement scenarios. ABATE points to Staff testimony and modeling that suggest operating Campbell 3 past 2025 may be more economical than the PCA suggests. Moreover, ABATE contends that Consumers used an incorrect depreciation rate for the Covert and CMS plants resulting in a higher net present value of revenue requirements (NPVRR) for the PCA compared to the Alternate Plan.

In response to the company's proposals, ABATE presented its own alternate plan (ABATE Plan), which is the same as Consumers' PCA except that it forgoes the purchase of the CMS plants in 2025 and operates Campbell 3 until 2039. ABATE contends that its plan is more economical than the PCA, highlighting the significant investments in Campbell that will still need to be recovered from ratepayers if the plant closes in 2025.

Next, ABATE takes issue with Consumers' proposal that the company own at least 50% of new supply-side resources. According ABATE, if the company believes that the current 50/50 ownership structure is not beneficial to customers, then Consumers should simply consider the economics of each proposal without regard to ownership.

Turning to the company's proposal to recover the net book value of the retiring units plus projected decommissioning costs, ABATE maintains that addressing any regulatory asset is outside the scope of this proceeding, adding that the amortization of any regulatory asset should not begin until the first rate case after the asset is retired. ABATE further argues that Consumers' proposal to earn a full return on the retired units is unreasonable and imprudent, reiterating that issues concerning retirement costs of the Karn and Campbell units should be addressed comprehensively in a rate case or other proceeding. Similarly, for decommissioning and community transition costs, ABATE asserts that some of these costs should be borne by the company and, because the costs do not involve the provision of utility service, no return should be authorized.

Finally, ABATE urges the Commission to deny the Code of Conduct waiver for the purchase of the CMS plants and to reject the company's financial incentive proposals for EWR, DR, and PPAs. ABATE contends that the purchase of the CMS plants, at a price in excess of the book value, is precisely the type of situation that the Code of Conduct is meant to address. Concerning the proposed FIMs and FCM, ABATE maintains that these incentives are unnecessary and excessive.

G. Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance

EIBC/IEI/CGA argue that the levelized cost of energy (LCOE) and levelized cost of capacity (LCOC) inputs that Consumers used for modeling wind and solar energy and battery storage were too high. EIBC/IEI/CGA contend that if these inputs were updated or corrected, Consumers could develop an economical portfolio of renewables and battery storage that would avoid the purchase of Covert and the CMS plants. EIBC/IEI/CGA further note that Consumers did not perform any modeling runs that evaluated the replacement of the Karn and Campbell units with a portfolio comprised of renewables and storage. Instead, Consumers' modeling "forced in" the Covert and CMS units and added incremental renewables and storage. EIBC/IEI/CGA therefore recommend that the Commission direct Consumers to (1) rerun its models with updated inputs for storage and renewables; and (2) evaluate a portfolio of renewable energy and storage to replace the retiring units, without assuming the addition of Covert and the CMS units, and on the same timeline used in the company's PCA. To determine cost and operational data for the renewable/storage portfolio, Consumers should undertake a competitive solicitation for all resources.

EIBC/IEI/CGA next take issue with Consumers' 2021 RFP, asserting that the solicitation limited diversity of supply and competition, contrary to the requirements of Section 6t(8)(a). EIBC/IEI/CGA add that although the Commission had not yet finalized the guidelines for competitive bidding at the time the RFP was conducted, it had nevertheless articulated the goals of competitive procurement, including technology neutrality, in the August 20, 2020 order in Case No. U-20852. EIBC/IEI/CGA further assert that Consumers' rationale for its gas-only RFP, namely that it was supported by the CSA, is faulty. According to EIBC/IEI/CGA, the CSA itself was rife with problems including its unconventional methodology, its comparison to an alternate plan the development of which was unclear, the use of load and outage scenarios that were unrealistic, and inappropriate assumptions about DR and CIL, among other things.

Next, EIBC/IEI/CGA recommend that the Commission direct Consumers to amend its IRP to include a meaningful evaluation of combined heat and power (CHP) as both a supply-side and demand-side resource. Noting that CHP is favored by both state and federal policy, EIBC/IEI/CGA list numerous benefits of CHP and discuss the CHP Roadmap for Michigan. EIBC/IEI/CGA point out that Consumers only considered one front of the meter CHP configuration, and it did not consider behind the meter CHP at all.

EIBC/IEI/CGA urge the Commission to recognize that Consumers' IRP modeling analysis contains numerous errors and therefore may not reflect the full amount of cost-competitive storage. EIBC/IEI/CGA point out that Consumers' modeling evaluated four storage prototypes with incorrect attributes and inappropriate constraints on storage additions. Further, EIBC/IEI/CGA urge the Commission to direct Consumers to procure 80-230 MW of energy storage resources by 2025, and that it require the company to conduct an all-source competitive solicitation to fill the remainder of its 2025 capacity needs. EIBC/IEI/CGA maintain that if the Commission follows Staff's proposal to require the company to perform further analysis of the retirement of Campbell Unit 3, it should require Consumers to update all its modeling in accordance with EIBC/IEI/CGA's recommendations.

Next, EIBC/IEI/CGA recommend that Consumers continue the 50/50 ownership model established in the 2018 IRP settlement agreement, noting that the 50/50 split could reasonably be applied over the 5 years of the PCA rather than annually. Nevertheless, EIBC/IEI/CGA argue that Consumers proposal to own "at least" 50% of new projects raises the possibility that the company could own all new supply-side resources. EIBC/IEI/CGA contend that 100% company ownership would not be reasonable and prudent because, even including the cost of the FCM, PPAs have been demonstrated to be more cost-effective than company-owned resources. EIBC/IEI/CGA add that the Commission should only approve the company's PCA if Consumers agrees to utilize the Commission's approved, albeit not mandatory, competitive bidding guidelines.

Next, EIBC/IEI/CGA highlight the importance and value of customer-owned distributed energy resources (DERs) to the grid, noting that Consumers only modeled these resources as load reductions, failing to evaluate their potential role on the supply side. EIBC/IEI/CGA point out that the Commission has determined that a complete evaluation of DG is imperative for IRP development, quoting the February 20, 2020 order in Case No. U-20471. EIBC/IEI/CGA urge the Commission to require Consumers to amend its IRP to model DERs as both potential load reduction and supply-side generation resources.

In a related concern, EIBC/IEI/CGA argue that Consumers should ensure that the growth of rooftop solar is not inhibited by artificially low caps on customer participation in the company's DG program. EIBC/IEI/CGA assert that instead of exploring the DG program recommended by Staff in the company's previous IRP, Consumers merely implemented a slight increase in the cap, from 1% to 2%. EIBC/IEI/CGA contend that this is not a permanent solution, since the company's program is expected to reach the 2% limit in 2023. Consumers should also clearly communicate alternative programs, like

PURPA, to customers wishing to implement rooftop solar, noting that Consumers' website does not provide this information. In addition, EIBC/IEI/CGA recommend that the Commission reject the company's proposal to eliminate the payment of full avoided cost to customer-owned projects under 150kW based on the company's claim that these projects are eligible to participate in Consumers' competitive solicitations. EIBC/IEI/CGA assert that simply because these small projects are eligible to participate in competitive solicitations does not mean that the owners of the systems have the time or technical capability to participate in the complicated bidding process.

Finally, with respect to PURPA and other PPA issues, EIBC/IEI/CGA note that the FERC has reduced the presumption of non-discriminatory market access from 20 MW to 5 MW for Consumers, yet rather than raising the Standard Offer cap from 2 MW to 5 MW, the company proposes to reduce the cap to 100 kW. According to EIBC/IEI/CGA, the Commission indicated, in the January 21, 2021 order in Case No. U-20905, that if a utility has been granted authorization to lower its presumption of non-discriminatory market access from 20 MW to 5 MW, that utility is expected to increase its Standard Offer tariff to 5 MW or provide a detailed explanation for why it did not do so. In this case, EIBC/IEI/CGA contend that Consumers' rationale for reduction in its Standard Offer tariff is unconvincing and should be rejected.

EIBC/IEI/CGA assert that the Commission should reject the company's proposal to shorten PPA lengths from 25 year to 10 or 15 years. Instead, the company should be required to continue to contract for PPAs whose term lengths correspond to the depreciation schedule for a similar company asset. Lastly, EIBC/IEI/CGA support an

FCM, provided that company ownership of new assets be limited to 50% and that the FCM be transparent and not so large as to cause PPAs to become disfavored.

H. Energy Michigan

Energy Michigan argues that the Commission should deny Consumers' request for approval to acquire the CMS plants, contending that the purchase of these plants would have an adverse impact on resource adequacy, reliability, and competitiveness in MISO Zone 7. Energy Michigan points out that MISO applies terms like LCR, PRMR, and resource adequacy to all of MISO as well as local resource zones within MISO. As such, the Commission should evaluate the IRP not just with respect to Consumers' service territory but all of MISO Zone 7. Considering this more expansive view, Consumers' proposal to retire units and purchase the CMS plants will result in less capacity in Zone 7, potentially affecting reliability. In addition, the purchase of the CMS plants may increase capacity prices and reduce competition in the zone as the same number of entities compete for fewer available resources.

Next, Energy Michigan urges the Commission to evaluate Consumers' proposed FCM holistically, noting that the current FCM was negotiated as part of a settlement agreement. Energy Michigan points out that the current FCM has two elements: total PPA payments and the after-tax WACC. Although Consumers proposes to change the second factor from after-tax to pre-tax WACC, Energy Michigan contends that the Commission should also consider whether the total PPA payments, which include variable costs of the PPA, should also be modified. In addition, Energy Michigan opposes Consumers' request to expand the FCM to all new and modified PPAs. According to Energy Michigan, the FCM incentivizes the utility in its decision to buy energy through a

PPA, rather than build a new resource. For existing PPAs, the build or buy decision has already been made and no incentive is required. Energy Michigan maintains that an FCM should only apply to new PPAs or extensions of existing PPAs.

Finally, Energy Michigan urges the Commission to petition the federal Energy Regulatory Commission (FERC) to make changes in the way that MISO calculates the LCR for Zone 7, noting the mismatch between the Zone 7 PRMR and the regional PRMR. Correcting this problem would reduce the LCR by over 500 ZRCs without any transmission upgrades.

I. Hemlock Semiconductor

HSC observes that Consumers currently does consider factors other than price in its competitive solicitations, however, the company is proposing to eliminate these value-added factors going forward. HSC disagrees, contending that Consumers should expand its bid pre-qualification process to include specific and transparent social, environmental, and governance components. Relying on Mr. Rausch's testimony, HSC argues that the Commission should direct Consumers to continue to consider value-added factors such as lifecycle carbon emissions, labor practices, and supply chain reliability in its competitive solicitations for solar.

Next, HSC states that it supports Consumers' proposal for regulatory asset treatment of the unrecovered balance of the retiring units as a reasonable approach to cost recovery. However, HSC opposes any recommendation that unrecovered amounts be securitized, contending that securitization is rarely used by utilities, characterizing this financing method as an insurance policy available for costly and unforeseen events. HSC argues that securitization can result in adverse impacts including risk compression, punitive write-offs, intergenerational equity issues, inability to use securitization if needed in the future, and investor risk that an asset may not earn a reasonable return over the life of the asset. HSC points out that Consumers has used securitization repeatedly, to the extent that the ratio of securitized debt to net plant is 8.51%, which would increase to 23.12% if the retiring units are securitized. HSC adds that the Commission does not have authority to direct Consumers to file an application for a financing order under MCL 460.6t or MCL 460.10i.

Nevertheless, HSC contends that if the Commission does order the company to apply to securitize the retiring assets, the Commission should make clear that any securitization surcharges do not apply to HSC, which takes service under a Long-Term Industrial Load Retention Rate (LTILRR) contract authorized under MCL 460.10gg. Under the LTILRR, HSC's rates are based on costs associated with the Zeeland generating unit, including retirement costs of that unit. HSC contends that it would be unjust and unreasonable to assign securitization costs to LTILRR customers.

J. Great Lakes Renewable Energy Association

GLREA criticizes Consumers' PCA as a significant departure from the approach in the company's first IRP, noting the proposed additions of gas generation and reductions in solar energy, EWR, and DR in this plan. GLREA argues that the company's PCA should be rejected and instead the Commission should approve a plan that includes: (1) the addition of 1000 MW per year of solar, with at least half comprised of third-party PPAs; (2) the possible addition of the Covert plant but not the CMS plants; (3) the closure of Campbell 3 when economic to do so and sufficient solar, DR, EWR, battery storage, CVR, and PURPA capacity are available to replace Campbell 3 capacity; and (4) the securitization or amortization of the remaining book balances of the retiring units with no return on the balances.

GLREA argues that in its IRP, Consumers unreasonably and artificially capped solar capacity additions to 500 MW per year, noting that Consumers' reasons for doing so are unavailing and that the modeling would have selected more solar if the amounts had not been constrained. GLREA adds that the market for solar has demonstrated that it could provide significantly more capacity than 500 MW per year. GLREA points to other errors in the company's modeling, including an understated ELCC for solar, no additional PURPA interconnection, a failure to include resources in the company's most recently approved VGP program, and Consumers' failure to properly model battery storage and EVs as DR resources or include community solar in its plan.

Next, GLREA takes issue with the company's plan to own at least 50% of new renewable supply-side resources, despite the significantly lower cost of PPAs compared to company-owned resources. In addition, GLREA contends that Consumers failed to consider the continued expansion of DG or evaluate opportunities for enhancing customer-owned solar.

GLREA criticizes Consumers' 2021 RFP, agreeing with Staff that the RFP structure and process were seriously flawed. Because of the deficient RFP, and because of the high cost relative to book value, GLREA contends that the Commission should reject the company's proposal to acquire the affiliated CMS plants. GLREA also agrees with Staff and ABATE that the company should undertake a more rigorous analysis of the proposal to retire Campbell 3 in 2025, including consideration of the health and mortality impacts of keeping the unit in service.

GLREA asserts that the Commission should reject the company's request for an increased FCM, expanded to apply to all new or modified PPAs, including PPAs for RPS compliance. GLREA maintains that Consumers has failed to demonstrate that the FCM is in ratepayers' interest. If the Commission decides that an FCM is appropriate, the mechanism should be structured in the same way as the FCM for DTE Electric was formulated in Case No. U-20713.

Finally, GLREA contends that, although it agrees that Consumers should recover the remaining book balance for the retiring assets, the company should not receive a full return on these retired units. And the depreciation rate assigned to any new gas plants should be based on their original design lives and not an artificial retirement date of 2040. According to GLREA, neither of these cost recovery proposals is just or reasonable.

K. Wolverine Power Supply Cooperative

Noting that it is a part owner of Campbell 3, WPSC raises three issues with respect to the proposed retirement of that unit. First, WPSC argues that Consumers' IRP and PCA do not support the early retirement of Campbell 3, and therefore the company's PCA is not reasonable and prudent. According to WPSC, the company's modeling of Campbell 3 retirement was incomplete because the modeling only evaluated one retirement year, and the company failed to undertake any sensitivity analysis (as it did for other retiring units). Moreover, Consumers' analysis does not demonstrate that early retirement of Campbell 3 will benefit customers.

Second, WPSC maintains that Consumers relied on unsupported assumptions about post-retirement capacity availability in Zone 7, noting that the company essentially "islanded" itself without considering capacity requirements for all of Zone 7. As such, WPSC contends that the 2025 retirement of Campbell 3 could jeopardize reliability in Lower Michigan.

Next, WPSC asserts that Consumers failed to fully account for all retirement and decommissioning costs of Campbell 3. WPSC points out that the net book value of the unit is estimated at $923 million at the beginning of 2023, a sum that does not include the unrecovered amounts pertaining to the other co-owners of Campbell 3. In addition, although WPSC maintains that it has paid a portion of decommissioning costs as a co-owner of the plant, Consumers was unable to provide an accounting of costs already collected and reserved, including decommissioning costs paid by WPSC per its agreement.

Finally, WPSC contends that Consumers breached its agreement with WPSC by failing to consult with the co-owners on its decision to retire Campbell 3 in 2025. In support of its claim, WPSC points to Article 18 of the Campbell 3 agreement which requires "mutual agreement on any 'major retirement matters[,]'"[88] noting that it was first informed of the retirement decision 30 minutes before Consumers made a public announcement. Consistent with the above, WPSC urges the Commission to reject Consumers' IRP.

L. Michigan Electric Transmission Company

METC notes that Consumers assumed an available CIL of 3,200 MW in its CSA modeling, thus it concluded that there was sufficient import capability so the there was no need invest in transmission upgrades to increase CIL. METC argues that Consumers' conclusion was in error and that an increase in CIL may be necessary for Zone 7 to meet

[88] WPSC brief, p. 11, Exhibit WPSC-1.

resource adequacy requirements. METC notes that currently, all of the Zone 7 CIL is committed; the CIL is shared by all Zone 7 providers on a pro-rata basis, and Zone 7 cleared the MISO planning resource auction (PRA) at cost of new entry (CONE) in 2020/2021 and it may do so again this year.

METC points out that because of plant retirements, the addition of significant amounts of renewables, and the limited CIL, transmission upgrades may be needed to increase import capability. METC adds that transmission investments would also allow more flexibility of supply and the ability to import less costly energy from other parts of MISO.

METC asserts that as the transmission system operator, it is in the best position to evaluate transmission needs, including increasing the CIL for Zone 7. Accordingly, the Commission should give significant weight to METC's transmission evaluation. Noting that Consumers requested a transmission analysis before developing its PCA, METC nevertheless maintains that the company disregarded METC's recommendations and instead overly relies on generation resources within Zone 7, risking reliability and increasing costs to customers.

M. Biomass Plants

Noting that Consumers proposes to add 7,800 MW of solar generation to its portfolio during the IRP period, the BMPs argue that the company's projected energy production from solar facilities is erroneous. According to the BMPs, the capacity factor for solar used in the company's modeling (using a Chicago proxy) is significantly higher than the actual capacity factor for any of Consumers' current solar facilities. In addition, the BMPs point out that Consumers failed to include a degradation factor for solar panels, nor did the company consider the potential for MISO to adopt a seasonal resource adequacy construct for solar generation, which could reduce the capacity assumption from 50% to 30% of nameplate.

Next, the BMPs argue that the company inappropriately excluded biomass generators from its modeling. According to the BMPs, Consumers assumed that it will not renew any contracts with biomass facilities once the current contracts have ended, contending that the company's rationale for this assumption is unavailing. The BMPs point to testimony that new biomass plants were screened out as too costly; but the BMPs assert that the biomass plants participating in this proceeding are not new construction. The BMPs add that Consumers also screened out the existing biomass generators because no information was available on the cost of contract renewal. According to the BMPs, Consumers did not approach the biomass generators about PPA extension or for any cost information.

The BMPs point out that the purchase of capacity from net-zero, non-intermittent resources would support the company's goal to reduce carbon emissions, and the 188 MW of capacity from these generators could replace the need to purchase the Kalamazoo and Livingston plants. The BMPs contend that Consumers in fact dismissed consideration of the biomass plants because of the company's desire to purchase the CMS units, despite the requirement of MCL 460.6t(1)(f)(iii) to include "any supply-side and demand-side resources that reasonably could address any need for additional generation capacity." The BMPs also contend that the capital and O&M costs for the Livingston and Kalamazoo peaker plants are exceptionally high and that the existing biomass generators provide the same advantages (or more) than the gas units the company proposes to purchase. The BMPs add that renewing the PPAs with these plants would avoid ownership risks associated with the purchasing Livingston and Kalamazoo; the BMPs increase generation diversity, and these plants provide employment in Michigan as well as tax benefits.

Finally, the BMPs urge the Commission to direct Consumers to revise its IRP to recognize the three types of generation at issue here: (1) non-intermittent fossil fuel generation; (2) non-intermittent biomass generation; and (3) intermittent renewable (i.e., solar) generation, recognizing the differing operational characteristics, risks, and costs, consistent with the "tiered" method FERC uses for evaluating avoided costs.

N. Citizens Utility Board

CUB focuses its argument on the level of residential DR contained in Consumers' PCA. CUB asserts that the Cadmus Demand Response Potential Study (Cadmus Study), on which Consumers relied in optimizing DR over the IRP period, contains several flaws that increased the cost and therefore limited the potential for increased residential DR.

CUB acknowledges that Consumers was required to use the 2017 Statewide DR Potential Study in developing its IRP, as the most recent statewide study available at the time the company was developing its plan, and Consumers commissioned the Cadmus Study, which was released to the company in mid-2020, which it also used in setting residential DR levels. Since that time, a more recent statewide DR study (the Guidehouse Study) was released in September 2021, containing more reasonable and updated assumptions for residential DR.

CUB argues the sources on which Consumers relied for projecting residential DR assumed a much lower line-loss factor for residential DR than is appropriate because residential customers are almost exclusively connected at the distribution level. Using the system line loss factor of 7.73%, rather than the 3.7% that the company assumed, increases the cost-effectiveness and savings potential of residential DR and is consistent with the Guidehouse Study assumptions. In addition, CUB asserts that Consumers failed to consider marginal line loss rates and T&D savings in its evaluation, thus compounding the underestimate of residential DR savings.

In addition, CUB points out that Consumers' assumptions about customer behavior, the potential for implementing DR in winter and in more extreme weather events, increased housing electrification, and future DR technologies should be reevaluated, consistent with the Guidehouse Study, and incorporated into the PCA. Finally, CUB urges the Commission to reject Consumers' proposal for a FIM equal to 20% of non-capital spending for DR, noting that the Commission recently rejected the same proposal.

O. Urban Core Collective

UCC supports the early retirement of the Karn and Campbell units; however, it opposes the company's request for a full return on the net book value of the units after retirement. UCC contends that it is unjust and unreasonable for Consumers to receive a return on these investments when it should have recognized the health and environmental impacts of the coal plants at the time the investments in these units were made. Alternatively, UCC recommends that the Commission direct the company to securitize the remaining book value of the plants. The UCC also recommends that Consumers publicly issue a transparent and concrete transition plan for the communities affected by the retirement of the Karn and Campbell plants in its next IRP, including employee retention or retraining and plans for redevelopment of the sites.

The UCC urges the Commission to deny Consumers' request to acquire the CMS plants, contending that the proposed transaction violates the Code of Conduct. UCC adds that even if the Commission finds that the purchase of the plants is consistent with the code, the acquisition is not reasonable and prudent because the company failed to fully consider the economic, environmental, and environmental justice costs and risks of additional investment in these fossil-fueled plants.

Next, the UCC argues that Consumers' EWR target is too low and that the company failed to adequately address the barriers to participation in EWR programs for low-income customers. Noting that more focus on low-income customers will help the company achieve higher amounts of energy efficiency savings, the UCC recommends that the Commission modify the IRP to include a minimum EWR target of 2%. In addition, the UCC contends that Consumers used unreasonable cost assumptions in modeling renewable energy; the company imposed an arbitrary cap on the amount of utility-scale solar it would acquire each year, and Consumers failed to adequately address DG and community solar. UCC recommends that the Commission direct the company to remove the caps on utility-scale acquisition and DG and that Consumers be required to modify its IRP to explicitly include community solar as part of its plan.

Finally, the UCC argues that Consumers' community outreach for this IRP, particularly to low-income communities and communities of color, was deficient. UCC maintains that Consumers should evaluate scheduling of its meetings to include night and weekend sessions and the company should make particular efforts to engage community leaders in low-income communities and communities of color. UCC add that the company's presentations should avoid technical jargon, and Consumers should clearly explain why certain recommendations made by community members cannot be incorporated into an IRP, similar to the way comments are addressed in the rulemaking process.

V.

DISCUSSION

A. Integrated Resource Plan and Proposed Course of Action

As presented in detail in Mr. Blumenstock's testimony, Consumers summarizes its IRP assumptions and the process for developing its PCA as follows:

> Consumers Energy developed the PCA based on the types of resources chosen by computer optimization models that select the least-cost portfolio of resources available. 3 TR 257. Using Energy Exemplar's Aurora software platform ("Aurora"), Consumers Energy optimized its resource plan and alternatives. 3 TR 257. Consumers Energy utilized its existing robust resource planning process, comprised of multiple inputs, calculations, and models, to meet the requirements set forth in MCL 460.6t and in the MIRPP, which were adopted by the Commission in Case No. U-18418. 3 TR 258, 266. As part of the IRP modeling process, Consumers Energy determined its capacity position and first year of need, identified viable resource options, and developed production cost models that included appropriate inputs and assumptions. 3 TR 267. A detailed summary of the amount of capacity anticipated from all existing assets (or planned), and the associated year those assets are available (assuming a 2023 retirement of Karn Units 1 and 2, a 2031 retirement of Karn Units 3 and 4, a 2031 retirement of Campbell Units 1 and 2, and a 2039 retirement of Campbell Unit 3), is shown in Exhibit A-6 (STW-3). The Company developed major modeling assumptions related to: (i) load forecast outlooks; (ii) existing supply and demand-side resources; (iii) existing renewable energy inputs such as output, capacity factor, and tax credits; (iv) existing and capacity expansion options for EWR programs; (v) demand-side management programs including direct load control, dynamic peak pricing ("DPP"), CVR, and incremental DR; (vi) operating parameters and capital and operating costs for new supply-side resources; (vii) network upgrade costs for all new generation resources; (viii) the amount of capacity import and export capabilities into and out of Local Resource Zone ("LRZ") 7 ("LRZ7"); (ix) the levels of effective load

> carrying capability ("ELCC") for new technology resources; (x) fuel price forecasts for coal, natural gas, and oil; (xi) existing PPAs with Non-Utility Generators; and (x) economic parameters such as the discount rate and fixed charge rate. 3 TR 271-274.[89]

For the reasons discussed in detail below, this PFD finds that, as set forth in Section 6t(7), the Commission should recommend modifications to the IRP and associated PCA.

B. Modeling and Modeling Assumptions

Ms. Walz provided extensive testimony on the modeling underlying the company's IRP and PCA.[90] Ms. Walz explained:

> [T]he PCA was developed based on the resources chosen by computer optimization models that select the least-cost portfolio of resources available. The outputs of the model highlight the types of resources th at provide the lowest cost to customers to meet resource planning requirements. . . .[t]he scenario and sensitivity modeling ultimately led the Company to select a portfolio of resources for its PCA that includes the purchase of existing natural gas resources as well as large amounts of solar, with lesser amounts of Demand Response ("DR") and battery storage resources providing a balanced portfolio.
>
> The development of this IRP includes thorough application of a variety of resource, operational, cost, and environmental inputs and data into computer-based models that developed short- and long-term resource plans. My direct testimony will demonstrate that the modeling process used to develop the IRP included in this filing was rigorous and comprehensive, consistent with good utility practice, followed the requirements detailed in Section 6t of Public Act 341 of 2016 ("Act 341 "), and ultimately was used to identify the key elements of the best IRP for Michigan for both short-term and long-term planning periods.
>
> Finally, my direct testimony will provide economic support of the Company's plans to exit coal within the next five years, invest in existing baseload generation resources to ensure electric supply reliability, invest in the growth of demand-side resources, and continue on the Company's clean

[89] Consumers brief, pp. 28-29.
[90] The IRP is provided in Exhibit A-2.

> energy plan of increasing levels of renewable energy resources over the next twenty years.[91]

Consumers summarized the steps the company undertook in arriving at its PCA in its initial brief:

> 1. Determine capacity position and first year of need;
> 2. Identify viable resource options;
> 3. Develop production cost models including appropriate inputs and assumptions;
> 4. Construct portfolios for evaluation;
> 5. Perform portfolio capacity expansion and production cost simulation analysis;
> 6. Evaluate portfolios using quantitative and qualitative measures;
> 7. Evaluate portfolios through scenario and sensitivity analysis;
> 8. Complete a risk analysis; and
> 9. Determine the most reasonable and prudent plant that meets the MPSC and company planning objectives, and considers stakeholder feedback.[92]

Several parties raised issues about specific approaches, assumptions, or omissions in Consumers IRP modeling. The company's capacity sufficiency analysis was of particular concern.

Referencing the requirements under Section 6t(8) that a utility demonstrate that its plan is "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs," Consumers described the objectives of its CSA as follows:

> This CSA was conducted to understand the sufficiency of a portfolio of resources to serve projected customer demand. 3 TR 324. As Ms. Walz explained, a CSA is similar to an [Loss of Load Expectation] LOLE analysis in that both studies seek to evaluate how a given portfolio of resources performs under a set of simulations in which relevant input variables are exaggerated to understand the likelihood that the resource capacity may be insufficient to serve hourly demand. 3 TR 324. The studies, however, may differ in a variety of ways including: (i) an LOLE study is generally done at the RTO level, while the CSA was done for the Company's footprint only; (ii) the metrics by which an LOLE determines sufficiency may be different

[91] 3 Tr 257-258.
[92] Consumers brief, p. 105, citing 3 Tr 267-280.

> than the metrics used by the Company in its CSA; and (iii) an LOLE study generally will solve to a North American Electric Reliability Corporation ("NERC") defined target and determine an appropriate planning reserve margin by adding resources to ensure the standard is met, while the CSA identified results through its metric and used the metric to judge the sufficiency of portfolios – that is, additional resources were not added through the CSA analysis, nor is a reserve margin identified as part of the solution. 3 TR 324.
>
> The goal of the CSA is to consider a pre-determined set of portfolio resources (supply or demand side) against a projected level of demand, identify the set of input variables that pose a risk to capacity sufficiency, and conduct a series of simulations that test the input variables compared to base levels. 3 TR 324. By varying the input assumptions, the simulations create extreme conditions under which the portfolio's ability to serve hourly demand is tested. 3 TR 324-325. When enough of these simulations are fun one can reasonably assess the probability of capacity insufficiency in every hour of the year. 3 TR 325.[93]

The company then used the CSA approach to evaluate the PCA and the company's alternate plan in 2032, a year which the company identified as having particular resource adequacy concerns. Staff, ABATE, and EIBC/IEI/CGA took issue with several aspects of the company's CSA.

Mr. Doherty testified that Staff had no concerns that the CSA focused on resource adequacy in 2032; however, Mr. Doherty explained that the company's conclusion that its PCA results in significant improvements in reliability compared to the alternate plan, "does not stand up to logic."[94] According to Mr. Doherty:

> Comparing the two portfolios in 2032, the PCA retires an additional 844 MWs of coal (785 MWs of which is owned by the Company), reduces solar built by 604 MWs, reduces battery storage built by 759 MWs, reduces demand response by 142 MWs, and builds nothing additional (acquiring only additional resources that already exist). The Company's CSA treats the purchased gas units as if they are new gas units and not existing units already producing energy. This is especially significant in the case of DIG, Kalamazoo, and Livingston (CMS units), because these resources already

[93] Consumers brief, pp. 176-177.
[94] 8 Tr 3488.

> exist in the same LRZ as the Company, serving customers within that RTO/LRZ, including those of the Company on a near daily basis. Other than the 3,200 MWs of import capability, the CSA treats the Company's resources and customers as if the Company was an "island" and not part of a larger grid connected to other LSEs within an RTO and part of a regional energy and capacity market. In practice, MISO would be responsible for administering any resource adequacy events through its emergency operations procedures. All energy produced by the Company's assets would continue to be sold through the MISO market and purchased by LSEs needing to serve load. Customers of one LSE are not prioritized over customers of a different LSE simply because one LSE has ownership of enough generation for all its customers and the other doesn't.[95]

He concluded that, based on the CSA, the PCA increases the likelihood that Zone 7 will not have sufficient resources to meet LCR, especially considering the fact that the company proposes to retire resources in Zone 7 and replace them with the CMS resources that are already counted toward Zone 7 reliability.[96]

Mr. Heidemann testified regarding the inputs to the CSA. Mr. Heidemann first explained that in the CSA modeling, the company allowed minimum and maximum load to increase or decrease by 23% and 27% respectively.[97] Mr. Heidemann described this load variation as "exceedingly robust,"[98] sufficient to account for all reasonable, and perhaps unreasonable futures, noting that the company used a much higher standard deviation for load fluctuation in the CSA than used elsewhere in the company's modeling.[99]

Mr. Heidemann testified that Staff found 3,000 modeling iterations for the CSA analysis to be sufficient; however, Consumers only modeled its own service territory with a limited CIL of 3,200 MW. Mr. Heidemann pointed out that DTE Electric can export 7,200

[95] 8 Tr 3488-3489.
[96] Id.at 3489.
[97] 8 Tr 3568.
[98] Id.
[99] Id. at 3569.

MW of energy into Consumers' service territory, but this capability was not included in the CSA modeling.[100] Mr. Heidemann recommended that in future IRPs, Consumers should increase the diversity in variable resource output files. In addition, Staff suggests that Consumers should also present a CSA that models all of Zone 7, not just the company's service territory in order to "provide a fuller picture of future reliability challenges."[101]

Similar to Staff's concerns, Mr. Dauphinais testified that the company's CSA analysis does not actually reflect the impacts of the company's planned retirements, noting that if the company replaces 1,000 MW with 1,000 MW that are already operating in Zone 7, the net loss of capacity in Zone 7 is still 1,000 MW. Thus, Consumers could still be vulnerable to a loss of load event if there is a shortfall in Zone 7, or in the MISO region.

Mr. Burgess criticized the CSA as a major underpinning the company's decision to issue a gas-only RFP in 2021.[102] Mr. Burgess testified that he had serious concerns about the methodology Consumers employed in conducting the CSA that may have biased the results and outcome that included gas plant purchases. Mr. Burgess specifically described the methodological flaws as: (1) the CSA only compared the PCA to the company's Alternate Plan, "whose development was not adequately justified or explained" and that was inconsistent with the Alternate Plan used elsewhere in the IRP modeling; (2) the scenarios evaluated in the CSA included a lack of support for the extremely high-load scenarios, incorrect or inappropriate pairing of solar, wind and load profiles, and a lack of correlation for plant outages; (3) the CSA included incorrect

[100] 8 Tr 3571.
[101] Id. at 3571-3572.
[102] 8 Tr 3314.

assumptions for DR; and (4) the CSA used a lower CIL than would be reasonable to expect in 2032.[103] Mr. Burgess added that only a limited set of the numerical results of the purported 3,000 modeling runs were provided, despite discovery requests.[104] Given these methodological flaws and lack of transparency in the inputs and process for developing the CSA, Mr. Burgess recommended that the Commission disregard the CSA as a reasonable basis for pursuing a gas-only RFP. Referencing Exhibit EIB-27, Mr. Burgess testified that correcting even one of the flaws in the company's CSA results in significant alleviation of the capacity insufficiency the company identified. Finally, Mr. Burgess recommended that the Commission direct the company to conduct a "truly" competitive solicitation including all resources.[105]

In response, Consumers argues that the concerns raised by Staff, ABATE, and EIBC/IEI/CGA should be dismissed. Consumers asserts that the 3,200 MW of CIL that it assumed in the CSA "was a proxy that represents market purchases available both inside and outside the zone," including potential purchases from DTE Electric. Moreover, Staff's criticism of Consumers failure to include 7,000 MW potentially available for import from DTE Electric should be rejected. Consumers points out that it would be unreasonable to assume that DTE Electric could provide that much energy if Consumers were facing a loss of load event.[106]

Consumers agreed that modeling all of Zone 7 as part of a CSA could provide more information about resource adequacy and reliability; however, the company maintains that it is neither necessary nor appropriate for Consumers to provide such a

[103] 8 Tr 3317.
[104] Id. at 3331.
[105] Id. at 3332.
[106] Consumers brief, pp. 183-184.

study when MISO performs the LOLE for all of Zone 7. According to Consumers, "[i]t is not the responsibility of the Company to evaluate the reliability of the entirety of MISO Zone 7 and subsequently make resource decisions for Consumers Energy customers, based on reliability needs outside of their service territory."[107] Finally, in response to Staff's and ABATE's concerns about the implications for resource adequacy in the purchase of the CMS plants, Consumers maintains that the plants were taken into account in the CSA in both the PCA and Alternative Plan evaluations as a company-owned resource or as available for import.[108] Referencing Ms. Walz's rebuttal testimony, Consumers emphasizes that the CSA was not an LOLE for Zone 7, it was a tool to compare the resource adequacy of two possible courses of action.[109]

Consumers also disagrees with EIBC/IEI/CGA's arguments, first pointing out that the description of the alternate plan used in the CSA was clear, contrary to Mr. Burgess's claim.[110] Second, while Consumers agrees with Mr. Burgess that there may be some correlation among variables, "it is still of value to compare the reliability of one portfolio against another without correlation, which was the purpose of the CSA analysis."[111] Third, Consumers contends that its modeling of DR was appropriate because the assumptions used reflect the way the company's DR programs actually operate, noting that Staff also found the DR modeling in the CSA reasonable. Finally, Consumers contends that the CIL it assumed for 2032 was reasonable, and that EIBC/IEI/CGA's data request for hourly data from the CSA would have resulted in over 6 million records.

[107] Consumers brief, p. 184 citing 3 Tr 362.
[108] Id. at 186.
[109] Id.
[110] Id. at 187, citing 3 Tr 404.
[111] Id. at 188.

Consumers notes that a no-cost temporary license to the Aurora modeling software, along with access to all of the modeling files, was offered to the intervenors, but EIBC/IEI/CGA did not take advantage of this opportunity.

The PFD finds that Consumers' CSA should be accepted and reviewed for informational purposes only. It is not clear to this ALJ what purpose the CSA serves, especially because it only compares two portfolios out of potentially hundreds of options that were not evaluated to determine if they met resource adequacy requirements.

Staff's concern about undertaking a CSA for all of Zone 7 has merit. As several parties point out, Consumers assumptions are not consistent with how MISO operates, where all resources are used to serve all loads, and where the company is never in fact "islanded." That said, the Commission may be in a better position to undertake this analysis as part of the capacity demonstration requirements under MCL 460.6w.

C. Unit and Plant Retirements

1. Retirement of Karn 3 and 4, and Campbell 1 and 2

As Consumers and many of the parties to this proceeding have observed, there is no opposition to the accelerated retirement of Karn 3 and 4 to 2023 and Campbell 1 and 2 to 2025. Consistent with what appears to be complete agreement on this part of the PCA, this PFD finds that the Commission should approve the company's plans to retire these units early. Consumers proposes to replace the capacity of these units with the acquisition of Covert in 2023 and the CMS plants in 2025, as well as with additional renewables and demand-side programs.

2. Retirement of Campbell 3

As part of the PCA, Consumers plans to accelerate the retirement of Campbell 3 from 2039 to 2025. Mr. DeCooman testified that although Consumers looked at different retirement dates for some of the company's units, the company only evaluated a 2025 retirement date, compared to the base retirement year of 2039, for Campbell 3. According to Mr. DeCooman, "the early retirement of Campbell unit 3 was only considered in concert with the other components of its PCA."[112] Mr. DeCooman observed:

> While the Company provided an economic analysis of the PCA, which includes the retirement of Campbell unit 3 in 2025, it did not provide specifics as to why this year was considered instead of or inclusive of additional retirement years aside from Campbell unit 3's current scheduled retirement date. As part of its IRP filing, the Company has identified separation costs that would be incurred at the Campbell unit 3 site in the event that Campbell units 1 and 2 retire in a different year than Campbell unit 3, as is currently scheduled. The Company estimates $64,146,000 in separation costs that it would incur unless Campbell unit 3 is retired in the same year as units 1 and 2.[113]

Mr. DeCooman questioned the separation cost estimate that the company provided, testifying that the estimate "was performed with the assumption that the Campbell plants would retire at the end of their design lives: 2031 for Campbell units 1 and 2, and 2039 for Campbell unit 3."[114] Mr. DeComman testified that these separation costs would need further scrutiny in the event Campbell 3 operated for a short period after Campbell 1 and 2 retired, noting that "Staff's findings are based upon a Company response to a Staff audit request that indicates Campbell unit 3 can operate while Campbell units 1 and 2 are on an outage[.]"[115] Mr. DeCooman summarized that Staff

---

[112] 8 Tr 3467; Exhibit S-4.3 and S-4.4 p. 5.
[113] Id. at 3467 (citations omitted).
[114] 8 Tr 3468.
[115] Id.; Exhibit S-4.8.

found that the economics of Consumers' decision to retire Campbell 3 in 2025 was not well supported because: (1) the company limited its analysis to only one retirement date; (2) Consumers only evaluated the early retirement of the unit in conjunction with other aspects of the company's PCA; and (3) the high capacity factor of Campbell 3 "makes the replacement of Campbell unit 3 more significant to meeting the Company's load obligations than the other generating units being proposed for early retirement in the PCA."[116]

Mr. Heidemann testified that Staff performed some modeling of the retirement of Campbell 3 in 2039, consistent with Consumers' Alternate Plan, evaluating other changes in solar and storage. Mr. Heidemann explained, however:

> Staff is not suggesting that Campbell unit 3 should retire in 2039 but was unable to identify the most reasonable retirement date for Campbell unit 3, given the retirement analysis performed by the Company. As discussed in Staff witness Jon J. DeCooman's testimony, the Company did not perform a rigorous retirement analysis of Campbell unit 3. Additionally, Staff could not run a supplementary retirement analysis on Campbell unit 3. The only two retirement dates considered by the Company were 2025 and 2039. Because capital spending may change due to the selection of a retirement date, Staff determined it would be a poor assumption to truncate the capital spending forecasts provided to represent capital spending under different retirement dates; certain capital projects may be deferred or moved forward based on retirement date changes. Staff would require significant guidance from the Company as to the exact changes for every retirement year analyzed.[117]

Mr. Dauphinais testified that Consumers should be directed to remove the early retirement of Campbell 3 from the PCA and provide a study of the cost effectiveness of early retirement of the unit in its next IRP.[118] Mr. Dauphinais discussed various loss of load probability (LOLP) studies and the challenges of addressing resource adequacy in

[116] 8 Tr 3470; Exhibit S-4.9, p. 1.
[117] 8 Tr 3587-3588.
[118] 7 Tr 2750.

the later years (more than five years out) in the IRP, especially considering the changes resulting from MISO's proposal to implement a seasonal construct for evaluating resource adequacy.[119]

Mr. Dauphinais observed that Consumers is "solely relying on an economic comparison between its PCA and its Alternate Plan to economically justify the early retirement of Campbell Unit 3 in 2025." He added that "[u]nlike with Karn Units 3 and 4 and Campbell Units 1 and 2, Consumers did not perform any sensitivity cases that focus on the early retirement of Campbell Unit 3."[120]

Mr. Dauphinais testified that Consumers' economic analysis of the PCA versus the company's Alternate Plan was in error because the company incorrectly calculated depreciation expense for Covert and the CMS plants. When this error is corrected, "Consumers' PCA has a forecasted NPVRR on a rate impact basis that is only $187 million lower" than for the Alternate Plan."[121]

Mr. Dauphinais criticized Consumers' LOLE comparisons between the PCA and Alternate Plan, testifying that the retirement of Campbell 3 coupled with the addition of the CMS plants, as assumed in the PCA, actually reduces reliability in Zone 7.[122] Mr. Dauphinais summarized ABATE's position on Campbell 3 retirement as follows:

- Unlike for Karn Units 3 and 4 and Campbell Units 1 and 2, Consumers performed no economic sensitivity analysis with respect to the retirement of Campbell Unit 3 earlier than 2039 either alone or in conjunction with Campbell Units 1 and 2;
- Consumers solely relies on its economic comparison of its PCA to its Alternate Plan to economically justify the early retirement of Campbell Unit 3;

[119] Id. at 2753-2754.
[120] Id. at 2763.
[121] Id. at 2761.
[122] Id. at 2762.

- Consumers' Alternate Plan is not a valid or viable alternative to Consumers' PCA as it does not likely provide sufficient resource adequacy in 2032 based on Consumers' own LOLP studies;
- The acquisition of the Affiliated Gas Generation Facilities would not be necessary in 2025 if operation of Campbell Unit 3 was continued beyond 2025 since the amount of ZRCs provided by Campbell Unit 3 in most years exceeds the amount of ZRCs that would be provided by the Affiliated Gas Generation Facilities;
- Unlike for the acquisition of the Covert Plant, the acquisition of the Affiliated Gas Generation Facilities would provide no new capacity to MISO Zone 7; and
- Consumers did not explore a portfolio in which it has pursued all of its PCA except for the early retirement of Campbell Unit 3 and the acquisition of the Affiliated Gas Generation Facilities.[123]

Mr. Dauphinais presented ABATE's alternate plan, which he described as having the same resources as the PCA, except that it keeps Campbell 3 running until its current retirement date in 2039 and does not include the acquisition of the CMS plants in 2025.[124] Citing Mr. Andrews testimony, Mr. Dauphinais explained that ABATE's economic analysis demonstrates that its alternative plan, on a rate impact basis, is $345 million less than the PCA, and ABATE's plan is likely more reliable.[125]

In rebuttal to Staff, Mr. Kapala agreed that if the company seeks to separate Campbell 3 from the other Campbell units, separation costs would need to be scrutinized, regardless of the timing of Campbell 3 retirement. Mr. Kapala added that the timing for retirement of the three units will have an impact on costs because Campbell 3 depends on certain operations provided by Campbell 1 and 2, and those operations must be maintained if Campbell 3 is retired after the other two units.[126]

[123] 7 Tr 2764-2765.
[124] Id. at 2674.
[125] 7 Tr 2765-2766.
[126] 7 Tr 1815-1816.

Ms. Walz reviewed the modeling performed by Staff noting that not retiring Campbell 3 in 2025 results in a significant capacity surplus, which in turn results in a higher NPVRR than the PCA.[127] Specifically, Ms. Walz testified that, "Staff Run IDs 262 and 263 create unreasonable and unnecessary amounts of surplus capacity. Further, without considering a range of capacity price values, Staff has overlooked the possibility of significant customer cost increases (as much as $686 million NPV) resulting from the proposed delay of all remaining coal-fueled generating unit retirements[.]"[128] Ms. Walz also presented Exhibit A-123, which shows the NPV of retirement of Campbell 3 in 2028, 2030, 2032. According to her:

> The NPV comparisons presented in this exhibit indicate that the delay of Campbell Unit 3 retirement to 2028, 2030, or 2032, and replacement of its capacity with alternative resources in lieu of acquisition of Dearborn, Kalamazoo, and Livingston is likely to increase customer costs. The range of cost impacts vary depending on the assumed price of natural gas, the assumed value of surplus capacity, and the type of resources replacing Campbell Unit 3's capacity.[129]

Consumers' brief relies on the rebuttal testimony of its witnesses, emphasizing that Campbell 3 retirement, coupled with the acquisition of the CMS units, is the most reasonable and economical path forward.

MNS contend that Campbell 3 should be retired in 2025, as Consumers recommends, with capacity shortfalls addressed through the purchase of Livingston only, and small purchases of capacity from MISO or through short-term PPAs. According to MNS, "delaying the plant's retirement—or deferring a decision on Campbell 3's retirement

[127] 3 Tr 350-353.
[128] Id. at 354.
[129] Id. at 369.

to a future IRP case—would expose ratepayers to unnecessary costs and unreasonable regulatory risks."[130]

Staff reiterates that Consumers failed to undertake a complete analysis of potential retirement dates for Campbell 3, and that the company's position, tying Campbell 3 retirement to the acquisition of the CMS plants is unsupported. Staff requested that Consumers evaluate multiple retirement years for Campbell 3, but the company omitted most of those years, despite the fact that there may be significant changes in capital spending from year to year. Staff further points out that although Consumers provided some additional modeling runs evaluating other resources, these modeling results were presented only weeks before Staff and intervenor testimony was due, giving little time to evaluate the results, adding that "[t]he supplemental modeling also included all other retirement decisions in the proposed course of action, thwarting efforts to isolate the Campbell Unit 3 retirement."[131] Finally, Staff argues that Consumers did not fully consider the innovative technology solutions that Staff recommended, noting the Consumers "forced in" 85 MW of reciprocating internal combustion engine (RICE) generation, with no explanation of how the company arrived at that amount.[132]

ABATE and WPSC do not support the early retirement of Campbell 3, on grounds that the 2025 retirement is not economically justified and that the accelerated retirement raises reliability concerns. ABATE recommends that the Commission adopt the ABATE alternative plan, which maintains the 2039 retirement date for Campbell 3, as the most

[130] MNS brief, p. 15.
[131] Staff brief, p. 24.
[132] Id. at 25.

reasonable and prudent approach to addressing long-term capacity needs on a more economical basis.

The PFD agrees with Staff that additional modeling of Campbell 3 retirement is necessary because the company's decision to retire the unit in 2025 is not well supported. This is particularly concerning because the company's modeling assumes that the remainder of the PCA, including the acquisition of the CMS plants, will be approved. As discussed in more detail below, the proposed purchase of these plants raises such significant questions about the cost, regulatory approvals, and environmental and other concerns that the PFD recommends that the Commission deny the purchase of those units.

The PFD agrees with Staff that Consumers should evaluate the retirement of Campbell 3 in isolation, with the objective of retiring the unit in 2025, but with analysis of other resource options, including the purchase of the Livingston plant, as MNS suggests, additional renewables, storage, and strategically installed RICE generation, as Staff recommends. This PFD also agrees with Staff and several intervenors that in undertaking this additional modeling, Consumers should update its input assumptions for solar and battery storage, using company results where possible, supplemented with more recent NREL data in cases where the company has limited cost or performance information.

D. <u>Supply Side Resources</u>

1. 2021 Request for Proposals

Mr. Troyer outlined the 2021 RFP process. In summary, Consumers hired Charles River Associates (CRA), and independent administrator, to conduct the RFP process. According to Mr. Troyer, in addition to Commission approval, the company will need authorization from the FERC pursuant to Section 203 of the Federal Power Act (FPA), which requires that for affiliate acquisitions, competitive solicitations must demonstrate (1) transparency; (2) precise definition of products solicited; (3) equal application of evaluation criteria; and (4) oversight by an independent administrator.[133] Mr. Troyer testified that the RFP process was designed to meet both the Commission's Code of Conduct and FERC requirements.

On January 6, 2021, CRA issued an RFP to satisfy potential capacity and energy needs in the next five years of up to 2,000 MWs. Prior to the solicitation, CRA contacted 10 potential bidders with likely eligible resources. Resources considered were existing natural gas fueled NGCCs or CTs located in Zone 7, or transferrable to the Zone. Through the RFP, Consumers solicited bids to acquire facilities sized between 50 and 1,400 MW. Proposals were due on February 26, 2021.[134] According to Mr. Troyer, five potential bidders submitted pre-qualification applications, and three of the five were not approved because they did not meet the requirement to be in service as of the issuance date of the RFP, or they were located outside of Zone 7 and could not be reclassified as Zone 7 resources.[135] As a result of the RFP, Consumers entered into an agreement to purchase the Covert plant and the CMS plants.[136]

[133] 4 Tr 706-708, referencing FERC's Edgar standards (*Bos. Edison Co. Re: Edgar Elec. Energy Co*., 55 FERC ¶ 61,382 (1991)) and the Allegheny guidelines for competitive solicitations (*Allegheny Energy Generating Co.* 108 FERC ¶ 61,082 (2004)) The *Allegheny* guidelines sometimes referred to as the *Ameren* principles.
[134] 4 Tr 703-704.
[135] Id. at 704.
[136] CMS Enterprises apparently offered the CMS plants in several combinations in different bids. The highest-scoring bid included all three plants.

Mr. Harlow testified that Staff has concerns with the overall RFP process, especially because it resulted in the purchase of assets from an affiliate. Focusing on the affiliate bids, Mr. Harlow explained:

> The RFP was so narrowly defined that Staff believes it would be difficult to accurately determine a fair market price for these assets. There are three specific items that, when combined, prevented this RFP from accurately gauging the market: specifying the units to be natural gas fueled, specifying that the units shall be located within/deliverable to MISO Zone 7, and, finally, requiring the units to be pre-existing.
>
> By narrowly specifying these items in the RFP, the Company essentially tailored the solicitation to a very small range of possible units that can only be located in or very near Zone 7. This prevents any opportunity to develop innovative solutions that could potentially be available in a relatively short timeframe. This resulted in only the owners of Covert, DIG, Kalamazoo, and Livingston being able to offer conforming bids. Therefore, it is possible that the respondents to the RFP could have known that there would be little competition and be able to submit conforming bids using less competitive terms and conditions. It also excludes non-gas generation technologies or combinations of technologies that may have similar operating characteristics to NGCC or NGCT being able to offer conforming bids. Therefore, Staff believes the Competitive Procurement performed by the Company is insufficient.[137]

Mr. Harlow noted, however, that although the company did not provide sufficient analysis of market value of the units in its application, in discovery, the company provided market reports from IHS Energy and S&P Global Market Intelligence providing average prices for NGCC and CT unit transactions.[138] Mr. Harlow stated that this discovery response, which demonstrates that the price per kW for Covert and the CMS units is within a reasonable range compared to other recent transactions, "increases Staff' comfort level with the reasonableness of the affiliate bids."[139]

---

[137] 8 Tr 3557.
[138] Id, at 3558; Exhibit S-10.0.
[139] 8 Tr 3558.

Like Mr. Harlow, Mr. Comings criticized Consumers IRP as far too restrictive, resulting in a limited number of qualifying bids, one of which included the CMS plants offered by a company affiliate. Mr. Comings suggested that "[t]he Company should have cast a wider net in terms of the resource replacement types—such as by conducting an all-source RFP."[140] Mr. Comings provided examples of two utilities that had done so as part of developing portfolios to replace coal generation. He noted that in both cases, the utilities:

> . . . sought a competitive, robust sample of bids and both ultimately advocated for early coal retirement combined with mostly renewable and storage replacement resources. By contrast, Consumers determined prior to issuing the RFP that all 2,000 MWs of capacity would be filled by natural gas capacity and tailored its RFP accordingly, which resulted in a very limited array of bidders from which Consumers could choose. Tellingly, while other utilities have fielded hundreds of resource options by seeking a competitive, less restrictive sample, Consumers received only four resource options and pursued all of them.[141]

Noting that Consumers appears confident that it will receive FERC approval for the acquisition of the affiliate CMS plants, Mr. Comings testified that given the flaws in the company's competitive solicitation, FERC may deny the transaction. Citing the *Allegheny* guidelines, Mr. Comings pointed out that the FERC has stated, with respect to the transparency guideline, that "'an RFP should not be written to exclude products that can appropriately fill the issuing company's objectives. This is particularly important if such exclusions tend to favor affiliates.'"[142] Mr. Comings opined that "Consumers' solicitation was so specific that it could be construed as directly targeting the CMS plants—after all, they represented three of the four qualified bids."[143] Mr. Comings further testified that

[140] 8 Tr 2976.
[141] Id. at 2977-2978.
[142] Id. at 2979, quoting *Ameren Energy Generating Co*., 108 FERC ¶ 61081, 61412 (2004).
[143] 8 Tr 2979.

while the definition guideline requires precision as to the products solicited, the definition should still not exclude reasonable options.

Mr. Comings also questioned whether Consumers complied with the FERC's "oversight" guideline in light of the company's extensive involvement in the RFP process.[144] Mr. Comings concluded that "[f]or Consumers to show FERC that the purchase of the CMS plants abides by all of the guidelines for inter-affiliate purchases will not be an open and shut case. It is at best questionable whether the transaction will pass muster under FERC standards."[145]

Referencing Mr. Blumenstock's testimony on the company's modeling efforts that resulted in the 2021 RFP, Mr. Evans testified that examination of the company's workpaper WP-STW-2 did not justify the issuance of an RFP. According to Mr. Evans:

- None of the Aurora runs selected new natural gas units in 2023 or 2024;
- Of the 113 Aurora runs tabulated in the chart, only six purportedly selected new natural gas units before 2031; and
- Of the six Aurora runs that purportedly selected new natural gas units prior to 2031, two were required to select only natural gas units, two were high load growth runs, one assumed the return of 50% of Retail Open Access loads, and one did not select resources at all.[146]

Based on his review of the company's Aurora runs, Mr. Evans opined that, "the Company's reliance on them was misplaced. These Aurora runs only selected new natural gas units before 2031 in cases in which only natural gas units could be selected, or load growth was higher than anticipated."[147]

Mr. Burgess testified that in his opinion, Consumers' RFP did not result in robust competition, with only two eligible bidders. According to him, "

[144] 8 Tr 2981.
[145] Id.
[146] 8 Tr 3049-3050 (citations to Aurora cases and workpapers omitted); Exhibit MEC 46.
[147] 8 Tr 3050.

> Not only is this a very low number of bidders, it is also fewer than those participating in RFPs conducted by Consumers in prior years. Additionally, it is the exact same number of bids that Consumers ultimately selected. Had Consumers allowed for additional technology categories, I am reasonably confident it would have received a greater number of bids, leading to more robust competition and potentially lower costs to Consumers' customers.[148]

In rebuttal, Mr. Troyer reiterated that, because the company relied on a third-party administrator, the RFP process was fair, and the bids represented fair market value for the units offered.

In response to Mr. Comings, Mr. Lee testified that that the RFP met the FERC's product definition guideline. He explained that all-resource RFPs, as Mr. Comings suggested, may be appropriate in some circumstances, "but they come at a cost as well[,]" noting that these types of solicitations tend to generate a much larger number of bids making the RFP process more complex and expensive, especially when comparing bids across technologies.[149] Mr. Lee testified that it was more appropriate to select resources as part of the IRP process and then undertake targeted RFPs for different technology types. He noted that when the RFP results in multiple technologies, it is more difficult to satisfy the FERC's evaluation guideline requiring unbiased scoring.[150]

In response to Staff, Mr. Lee pointed out that Mr. Harlow's testimony was contradictory: on the one hand supporting the acquisition of Covert at the price derived from the RFP while on the other hand criticizing the RFP process. According to Mr. Lee, "[i]t is unclear from Mr. Harlow's testimony why a 'flawed' RFP structure would only impact CMS Enterprises bids . . . and not the bid for the Covert Plant."[151]

[148] 8 Tr 3299; Exhibit EIB-3.
[149] 3 Tr 517.
[150] Id. at 518-519.
[151] Id. at 520.

In response to Mr. Comings claim that the RFP process may violate the *Allegheny* transparency guideline, Mr. Lee disagreed, testifying that transparency, in this context, has to do with the flow of information to all parties to ensure an open and fair solicitation. It does not apply to the scope of the RFP. He also disputed Mr. Comings' claim that the RFP specifically targeted the CMS plants, testifying that:

> Consumers Energy's overall RFP targeted 2,000 MW. The need in Consumers Energy's RFP is more than double the bid submitted by the affiliate. In addition, the targeted MW are only a small fraction of the total existing natural gas fired capacity in LRZ7. Consumers Energy was targeting a greater number of MW than was bid by their affiliate and there were an even greater number of qualifying MW in LRZ7 capable of being bid into the RFP.[152]

In cross-examination, Mr. Lee discussed CRA's and Consumers' review of existing assets in Michigan, as shown in Exhibit MEC-103, including the CMS plants, that appeared to meet the criteria in the RFP.[153] According to Mr. Lee, there was sufficient possibility that company affiliates would participate, that he discussed the need for compliance with FERC competitive bidding guidelines.[154]

Mr. Lee was also questioned about his involvement with another RFP, which CRA designed for Monongahela Power (Mon Power), which was similar to the RFP CRA managed for Consumers.[155] Mr. Lee admitted that the acquisition at issue in the Mon Power RFP was denied by the FERC for failing to meet the definition and evaluation principles under *Ameren*.[156] He also admitted that one of the reasons the Mon Power

[152] Id. at 524.
[153] 3 Tr 543-544.
[154] Id. at 546-547.
[155] Id. at 549; Exhibit MEC-102.
[156] 3 Tr 553-554.

acquisition was denied was because the RFP was overly narrow because it excluded PPAs, as did the Consumers RFP.[157]

In its brief, Consumers largely relies on testimony by its witnesses, emphasizing that the RFP was designed to comply with the Commission's Code of Conduct and FERC competitive bidding guidelines, noting that the 2021 solicitation was similar to others conducted for Consumers and DTE Electric by CRA.[158] Consumers adds that its decision to conduct a gas-only RFP was based on the company's modeling that demonstrated that the addition of natural gas to replace retiring coal units was the most economical choice. Consumers avers that it appropriately relied on the recommendation of CRA, the third-party RFP manager, in its decision to purchase the Covert and CMS plants.

Staff maintains that Consumers RFP process was flawed "leading to few conforming bids and ultimately to the Company's proposal to purchase the CMS Units at an unreasonable and imprudent price." Staff points to Exhibit MEC-102, which lists 22 potential gas plants from 10 suppliers with capacity in or deliverable to Zone 7. Staff points out that of those 22 units, only four could have been expected to respond to the RFP, because the remaining units were already in service with other investor-owned utilities, cooperatives, or municipal utilities. Staff points to cross-examination of Mr. Troyer where he agreed that the four plants that submitted bids were the only ones expected to do so.[159]

MNS repeats that Consumers RFP was too narrow to avoid a preference for the affiliated CMS plants, noting that three of the four plants ultimately selected are owned by

[157] 4 Tr 597.
[158] Consumers brief, p. 131.
[159] Staff brief, p. 53.

CMS Enterprises. Relying on Mr. Coming testimony, MNS argues that the RFP does not conform to FERC principles for competitive bidding, pointing to the FERC's order denying the Mon Power transaction, the circumstances of which are very similar to the proposed transaction at issue here. Like Staff, MNS points out that other than the Covert and CMS plants, Consumers did not expect the other 18 units to bid on the RFP, delineating that seven of the plants are owned by DTE Electric and were not expected to bid; the MCV and Michigan Power LP plants already have PPAs with Consumers and were not expected to bid; and four of the plants are owned by WPSC, which was not expected to bid. The remaining five plants are owned by municipal utilities, MSU, and Michigan Public Power Agency, and Mr. Troyer had no information indicating that these units were for sale.[160] According to MNS, '[i]n sum, of the 22 plants eligible to bid in the RFP, the only ones Consumers believed were interested in participating were Covert and the CMS plants."[161]

The PFD agrees with Staff and MNS that Consumers 2021 competitive solicitation was flawed, resulting in one reasonable bid (Covert) plus an affiliate bid at a price that does not comport with the Code of Conduct, as discussed below. While not purporting to speak for the FERC, the PFD also finds that the RFP and process may not comply with the FERC's competitive solicitation guidelines as set forth in *Allegheny*.

Specifically, the PFD finds that even if the RFP were limited to certain resource options, Consumers could have solicited PPAs to address the capacity need, and the company should have sought bids from BMPs, generators that have many of the same

[160] MNS brief, pp. 57-58, citing 4 Tr 851-852.
[161] MNS brief, p. 58.

operating characteristics as natural gas units that could have filled close to 200 MW of the capacity need. As MNS points out, the RFP limitations in the instant case are quite similar to the RFP in Mon Power that was denied by the FERC.

Consumers appears to believe that because the CMS plants only bid about half the capacity the company solicited, this somehow demonstrates that the RFP was unbiased. However, as Staff and MNS point out, Consumers seems to have been aware, before the issuance of the RFP, that the majority of the gas plants the company identified as meeting the qualifications of the RFP were already committed to providing service to other load serving entities and were therefore unlikely bid in the RFP. And, indeed they did not.

Consumers also relies on the price benchmarking shown in Exhibit S-10.0 to support its claim that the RFP resulted in competitive bids and market-based prices.[162] However, as MNS observes, Consumers did not take the age of the plants into account in its benchmarking, and it did not consider the price of the individual CMS units, or the cost differential between NGCC and NGCT units. The PFD agrees and finds that the benchmarking performed by the company does not support its claim that the price of the CMS units is fair.

Consistent with the discussion above, the PFD recommends that Consumers 2021 solicitation does not support the acquisition of the CMS plants.

2. Covert Plant

Mr. Battaglia described the Covert plant as an existing 1,176 MW nameplate capacity natural gas combined cycle (NGCC) facility, commissioned in 2004, and located

[162] 5 Tr 1222-1223

in Covert, Michigan. Although the Covert plant has operated in MISO at times in the past, the plant currently offers generation into the PJM market.[163] Mr. Battaglia further described the Covert plant as "an extremely flexible and reliable plant which was designed to take advantage of rapid-changing load and market conditions[,]" adding that the plant turbines have been upgraded "to produce more electrical power at a higher rate of efficiency so the units have a nominal heat rate of 7,000 [British thermal units]Btu/kWh."[164] The cost of the Covert plant, inclusive of closing costs, is $815 million.

A few parties suggested that the acquisition of the Covert plant might be unnecessary or imprudent, citing: concerns that the capacity need the plant is intended to fill could be addressed by additional renewables, demand side resources, and storage; the risk of volatile natural gas prices; high emissions from the Covert plant; environmental justice concerns near Covert; and the trade-off between reducing CO_2 emissions from coal and increasing emissions from methane, a more potent greenhouse gas. However, in briefing, most parties were either silent on the issue or agreed that the purchase of the Covert plant was reasonable.[165, 166]

GLREA contends that the depreciation rate the company used in its modeling of Covert was "accelerated" because Consumers assumes that the plant will retire in 2040, although the expected remaining life of the plant is 38 years. ABATE contends that the depreciation rate used in the modeling was too low and would result in significant stranded

[163] 5 Tr 1199.
[164] Id. at 1200.
[165] See, e.g., EIBC/IEI/CGA brief, p. 17 ("there could be a viable scenario that includes the Covert resource addition[.]"); GLREA brief, p. 26 ("[the Commission] should approve recovery of the reasonable costs of the proposed acquisition of the Covert gas plant, and its migration to the MISO grid."); UCC brief, p. 16 ("Covert is a sensible means of enabling the retirement of the Company's coal plants[.]");
[166] Staff, MNS, and ABATE support the Covert purchase, while the Attorney General, WPSC, and METC do not take a position on the acquisition of Covert.

costs assuming a 2040 retirement date. Consumers responds that the 5% depreciation rate it used for calculating the cost of the PCA is reasonable and that the actual depreciation rate for the Covert plant will be set in a depreciation case.[167]

The PFD agrees that the issue of the actual depreciation rate to be applied to the Covert plant is beyond the scope of this proceeding.

3. CMS Plants-Other Issues

As discussed above, this PFD finds that Consumers should reevaluate the retirement of Campbell 3, analyzing alternative resource options, with the objective of retiring the unit in 2025, or as soon thereafter as possible. In addition, the PFD found that the RFP process that resulted in the selection of the CMS plants was biased in favor of company affiliates. Finally, as discussed below, the PFD finds that the price Consumers proposes to pay for the acquisition of the CMS plants violates the Code of Conduct. However, if the If the Commission finds that the acquisition of the CMS plants may be reasonable, the PFD provides this brief review.

In addition to the problems discussed above, parties raised other concerns about these units including: (1) additional cost risks associated with unresolved environmental issues at DIG and Kalamazoo;[168] (2) higher fixed costs at some of the CMS plants;[169] (3) additional fuel price risk associated with replacing coal with natural gas;[170] (4) significant emissions, public health, and environmental justice concerns for the DIG facility in particular;[171] and (5) the impact of methane emissions on climate;[172] among other issues.

[167] 7 Tr 1632.
[168] See, e.g., 5 Tr 2883-2887.
[169] See, 8 Tr 3905-3906.
[170] See, 8 Tr 3762-3768.
[171] See, 7 Tr 2371-2395.
[172] See, 8 Tr 3744-3747.

If the Commission decides to further evaluate the acquisition of the CMS plants, it should also consider these additional concerns.

4. CMS Plants-Acquisition Premium

As discussed in detail above, this PFD finds that: (1) Consumers retirement analysis for Campbell 3 was deficient, and because the acquisition of the CMS plants is intended to replace capacity from Campbell 3, the purchase of the CMS plants is not presently supported; and (2) Consumers 2021 RFP process and results did not result in bids that reflect fair market value or an arms-length transaction for the CMS plants. Thus, this PFD recommends that the Commission deny approval of any costs associated with the purchase of the CMS plants.

However, if the Commission determines that the acquisition of these plants is reasonable and prudent, the issue of whether it is just and reasonable to include recovery of the acquisition premium must be addressed. Several parties oppose allowing Consumers to recover an acquisition premium for the CMS plants for reasons including that any such allowance is contrary to the Commission's acquisition premium standard, FERC's acquisition premium standard, or the Commission's Code of Conduct.

Consumers disagrees, asserting that the Commission's prior orders addressing acquisition premiums do not apply because the CMS plants have never been devoted to public service, no risk exists that captive regulated utility customers will pay for them twice, and the purchase price reflects the fair market value.[173] Consumers adds that the FERC orders cited by Staff and intervenors do not support disallowance of an acquisition premium, and that while the FERC's orders are not strictly applicable to this case, if they

[173] Consumers Initial Brief, p. 273.

were, Consumers has satisfied FERC's benefits exception.[174] In addition, Consumers argues that the acquisition of the CMS plants complies with the Code of Conduct, but if the Commission concludes that the purchase does not satisfy the Code of Conduct, the Commission should grant a waiver of the pertinent rule.[175]

As an initial matter, this PFD agrees with Consumers that the FERC orders and policies, which were debated at *considerable* length in testimony and briefing, are simply not applicable here.[176] Therefore, the PFD's discussion of what the FERC would or would not do if faced with the circumstances presented in the instant case, is cursory. In addition, the ALJ observes that the Commission's acquisition premium standard, also addressed extensively by the parties, has limited applicability, because the majority of the cases cited either did not involve affiliate transactions, like the one at issue in the instant case, or they were decided before the current Code of Conduct was promulgated.

As discussed below, this PFD finds that approving an acquisition premium as part of the cost of the CMS plants would violate the Code of Conduct. In addition, the PFD finds that Consumers' request for a waiver of the Code is unsupported and should therefore be denied as well.

Staff opposes the company's request for an acquisition premium for the CMS plants on several grounds. Mr. Proudfoot testified:

> If the Commission chooses to approve the PCA, Staff recommends the Commission not pre-approve the acquisition premium for inclusion in rates for the proposed CMS unit purchases and direct the Company that the

---

[174] Id., p. 281.
[175] Consumers Reply Brief, p. 103, 115.
[176] If the Commission decides to address the applicability of the FERC's acquisition premium benefits exception, it should be noted that company witness Kelliher misrepresented FERC's precedent regarding the scope of its benefits exception and a federal appellate court's assessment of that exception. See, Mr. Kelliher's discussion of *Missouri Public Service Comm'n v FERC,* 783 F.3d. 310 (D.C. Circ 2015) at 7 Tr 1856-1857.

> acquisition premium is not recoverable in rates unless the Company can provide the following analysis in a form satisfactory to the Commission. This would result in a rate base for the CMS units that does not exceed the original purchase amount less accumulated depreciation unless the Company presents an analysis that clearly illustrates specific and non-speculative benefits to ratepayers. This analysis would require the utility to isolate the decision to purchase CMS units as compared to alternative resources utilizing the most recent Annual Energy Outlook gas price.[177]

Staff points to the Commission's prior orders in Case Nos. U-9323, U-13808, U-13898, and U-14672 in support of its position that Consumers should not be allowed to recover the acquisition premium in this case. For example, Staff notes that in Case No. U-9323, "[t]he Commission concluded that Michigan is an original cost jurisdiction and that customers must receive a net benefit from a change in ownership before an acquisition adjustment can be approved."[178]

Staff acknowledges Consumers' rebuttal, that circumstances in this case are different from the prior Commission cases because the CMS plants "have not been previously used in utility operations or in the public service, and thus regulated utility customers have not paid for these plants through retail rates."[179] However:

> This difference . . . does not alleviate Staff's concerns that the [CMS units] are being purchased from an affiliate and are not arms-length transactions.
>
> Moreover, whatever factual distinctions exist between the instant case and past cases where the Commission rejected requests for acquisition premiums, the fundamental principles the Commission announced in past cases should continue to apply. These principles caution against approving an acquisition premium for affiliate transactions unless there is net benefit to customers.[180]

[177] 8 Tr 3401.
[178] Staff brief, pp. 71-72.
[179] Id., pp. 73-74, quoting 7 Tr 1620.
[180] Id., p. 74.

Staff adds that its position is consistent with the FERC Uniform System of Accounts (USoA) and with the “Accounting for Public Utilities” treatise, which explains that that the “original cost” method came about because holding companies had a history of inflating regulated utilities’ rate base by selling their affiliates’ assets to regulated utilities at prices above the “value” of the property. And, Staff maintains that its recommendation to deny recovery of the acquisition premium comports with the “benefits exception” employed by the FERC in its evaluation of acquisition premiums.

Finally, Staff asserts that the Commission’s Code of Conduct requires that the transfer of an asset to an affiliate be at the lower of cost or fair market value, quoting from Code of Conduct Rule 8(4), Mich Admin Code, R 460.10108(4) (Rule 8(4)), which provides, “Asset transfers from an affiliate or other entity within the corporate structure to a utility for which the cost is not governed by MCL 460.10ee(8) shall be at the lower of cost or fair market value.[181] Staff adds that an asset transfer that does not comply with this provision of the Code of Conduct would require a waiver from the Commission.[182]

Staff argues that Consumers has not shown that the purchase price for the CMS units is the lower of cost or fair market value. Staff asserts that Consumers has a skewed view of “cost” and “fair market value” as those terms are included in the Code of Conduct. According to Staff:

> The Company believes that its proposed purchase of the CMS Units does not violate the Code, even though it is between affiliates, because the “fair market value” of the plants, which the Company claims should be based on its competitive solicitation, is less than the “cost” as the Company interprets “cost.” According to the Company, the term “cost” in Rule 8(4) of the Code of Conduct is the utility’s fully embedded cost of capacity. Thus, the Company compared the embedded cost of capacity of its existing

[181] Staff initial brief, p. 75.
[182] Id., citing Case No. U-20512, Order, July 2, 2019, p. 3.

> generation fleet to the supposed fair market value of the assets proposed for purchase to determine whether the purchase price violated the Code of Conduct. It claimed there was no violation because the fair market value, represented by the purchase price, was less than the Company's own embedded cost of capacity.[183]

Staff argues that Consumers' embedded cost of capacity is "not a fair proxy for the cost of CMS's aging units" and that the proposed purchase prices "are not a fair proxy for market value" because the solicitation process was not truly competitive.[184] Staff further asserts that defining "cost" to be the buyer's fully embedded cost of capacity "cannot be squared with the rules of statutory construction," which also apply to administrative rules.[185] Staff argues that the rules of statutory construction demand different words used in the same or similar statutes be given different meanings. As such, since the term "fully allocated embedded costs" is used in Rule 8(4) to describe the cost of products and services being exchanged between utilities and their affiliates, the term "cost" used later in the subsection to describe the cost of an asset transfer between utilities and affiliates cannot refer to "fully allocated embedded costs."[186]

Staff argues that its position that "cost" in the context of Rule 8(4) is synonymous with "book price" and "net book value" is consistent with the rules of statutory construction as Staff ascribes different meaning to different terms used to describe costs. In addition, Staff asserts that its interpretation "makes more sense than the Company's interpretation." Staff maintains that:

> The Company assumes that a buyer's fully allocated embedded cost is the measure of "cost" when comparing "cost" with "fair market value" under the asset-transfer provision in the Code of Conduct, but the Company acknowledges that there would be no way to determine CMS's embedded

[183] Staff, p. 76.
[184] Id., p. 76-77.
[185] Id., p. 77 (citations omitted).
[186] Id. (citations omitted).

> cost of capacity if their roles were reversed and CMS was the buyer and Consumers the seller. By contrast, cost is readily discernable— regardless of the identity of the buyer and seller—if the net book value of the asset being transferred is the measure of cost.[187]

Staff adds that the term “fair market value” used in the Rule 8(4) of the Code of Conduct is synonymous with the term “Prevailing Market Pricing” used in the “NARUC Guidelines for Cost Allocations and Affiliate Transactions.” According to Staff, the NARUC Guidelines describe “Prevailing Market Pricing” as “a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.” Just like the Code of Conduct, the Staff notes that the NARUC Guidelines require that an asset transfer be at the lower of the “Prevailing Market Pricing” or cost, which the Guidelines measure using “net book value”:

> Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.[188]

Staff observes that NARUC’s Board of Directors recommended that the Guidelines be used by state regulators as a model, and that when the Commission rewrote its Code of Conduct, “this is exactly what it did", including the same comparison that the NARUC Guidelines include for asset transfers between affiliates.[189]

In rebuttal, Mr. Troyer disagreed that “cost” in the context of Rule 8(4) is synonymous with “book price” and “net book value,” citing as support Staff’s agreement with Consumers’ position in Case No. U-17725.

> Consistent with the Company’s position in Case No. U-17725, which was previously agreed to by Staff, for the purposes of a Code of Conduct, the

---

[187] Id., p. 78, citing 4 Tr 823-824.
[188] Id., p. 78-79 (citations omitted).
[189] Id., p. 79 (citations omitted).

> "cost" considered should be the cost to the utility. The utility's cost should be the basis for this test because it assures that a transaction with an affiliate does not adversely affect the utility's cost structure and corresponding customer rates by causing the cost per unit of service, product, or property to rise above its average or fully embedded cost.[190]

Staff counters that the circumstances in Case No. U-17725 were different than the present case because the Code of Conduct was different at the time and Consumers was purchasing a commodity or service, so it appropriately referenced Section III.C of the then-current Code of Conduct: "If an affiliate . . . provides services, products, or property to an electric utility . . . compensation for services and supplies shall be at the lower of market price or 10% over fully allocated embedded cost."[191] Staff asserts that, unlike transaction in Case No. U-17725, in this case Consumers is purchasing an asset from an affiliate, and that the Code of Conduct provision governing asset transfers no longer refers to "fully allocated embedded cost" like the previous Code of Conduct. Staff adds that the word "cost," which the new Code of Conduct substituted for the phrase "fully allocated embedded cost" in the old Code of Conduct, must be given a different meaning than the phrase it replaced.[192]

Finally, Staff argues that its interpretation of the Code of Conduct is consistent with its intended purpose, and that Staff uses the same units in its cost comparison. Noting that Consumers concedes that "preventing preferential treatment [between a utility and its affiliates] is one of the purposes of the Code of Conduct," and that another is to prevent "cross-subsidization to the detriment of our retail customers," Staff argues that the Code of Conduct must be interpreted with these purposes in mind.

---

[190] Id., citing 4 Tr 774.
[191] Id., p. 80
[192] Id., p. 80-81, citing *In re Childress Trust*, 194 Mich App 319, 326 (1992) ("In construing an amendment of a statute, we presume that a change in phrasing implies an intent to change the meaning as well.").

> The acknowledged purposes of the Code of Conduct, and the case law requiring administrative rules to be interpreted to accomplish their objectives, supports Staff's interpretation of "cost," as that term is used in the new Code of Conduct. Using "original cost" or "net book value" as the measure of "cost" in the Code ensures that a utility is not passing on inflated costs to its ratepayers by purchasing an asset from an affiliate for more than it is worth and including this high cost in base rates. By contrast, using the buyer's embedded cost of capacity as the measure of "cost" provides little if any protection to ratepayers.[193]

Noting that the Commission has not yet interpreted "cost" since the new Code of Conduct rules were promulgated, Staff recommends that the Commission follow the spirit of the "NARUC Guidelines for Cost Allocations and Affiliate Transactions," and find that "cost" in the context of a Rule 8(4) asset transfer is synonymous with "net book value."[194]

Like Staff, the Attorney General asserts that if approved, Consumers' proposal would result in an "impermissible acquisition premium."[195] Dr. Dismukes recommended that the Commission disallow recovery of the acquisition premium and allow recovery only of the remaining book value of the CMS units. The Attorney General also notes that in its order in Case No. U-9323, "the Commission has only allowed acquisition premiums to be recovered in rates if a public utility can show that ratepayers will receive a net benefit from the acquisition when including the premium."[196]

The Attorney General argues that the Commission should accord "no weight to Consumers' assertions that it has demonstrated that the acquisition premium satisfies the [Commission's] benefits test."[197] The Attorney General notes that Consumers initially took

---

[193] Id., p. 81, citing *In re Forfeiture*, 432 Mich 242, 248 (1989) (holding that if the meaning of a statute is in question "a court must look to the object of the statute, the harm which it is designed to remedy, and apply a reasonable construction which best accomplishes the statute's purpose.") (Other citations omitted).
[194] Id., p. 82.
[195] Attorney General brief, p. 46.
[196] Attorney General brief, p. 48, citing 7 Tr 2114.
[197] Attorney General reply brief, p. 27.

the position that it need not demonstrate that there are net benefits outweighing the premium, and that evaluating the benefits associated with the acquisition premium would be "complex and time-consuming" and would not be expected to add value.[198] However, Consumers then shifted its position in rebuttal to suggest that, if such a showing is required, then it has been made in this case.[199] As a result, there is "little or no record for regulatory approval of rate recovery of the $430 million acquisition premium", and where interveners had "limited opportunity to evaluate and counter [Consumers'] new position."[200]

In response to Staff's position on the Commission's evaluation of net benefits, the Attorney General disagrees regarding the applicability of Commission precedent in one respect, asserting that Commission precedent does not suggest that an acquisition premium in <u>affiliate transactions</u> may be approved if there is a net benefit to customers. According to the Attorney General:

> Staff acknowledges that, unlike in the three cases just discussed, the transaction at issue in this case involves the purchase of assets from an affiliate. Staff nevertheless notes that principles articulated in prior Commission decisions should continue to apply, and those principles "caution against approving an acquisition for affiliate transactions unless there is a net benefit to customers." . . .[T]his caveat appears to suggest that both the principles and the potential "net benefits" exception may apply in this case. In other words, Staff appears to suggest that rate recovery of an acquisition premium may be appropriate, even in the transfer of an asset between affiliates, where there is a demonstrated net benefit to customers. Neither case supports the conclusion that ratepayers should pay for an acquisition premium when an asset is transferred between affiliates, regardless of whether there is a demonstrated net benefit. The cited cases do not address this situation, nor should they be extended to this case.[201]

[198] Id., citing 7 Tr 2110-2112 (quoting Company Response to data Request AG-376).
[199] Id., citing 7 Tr 1615-1624.
[200] Id., citing December 17, 2020 order Case No. U-20697 pp. 16-20 (explaining that Consumers must present a sufficiently detailed direct case where it seeks regulatory approval for cost recovery through rates).
[201] Attorney General reply brief, p. 22-23.

Next, the Attorney General argues that while Staff's references to the FERC USoA and the net benefits test applied in FERC cases are correct, the FERC net benefits test "is not helpful or applicable in this case[,]" because the FERC benefits exception for acquisition premiums only applies to non-affiliate transactions.[202]

The Attorney General generally concurs with Staff's Code of Conduct analysis:

> [A]bsent a waiver, Rule 8(4) prohibits Consumers from acquiring an asset from its affiliate at more than the lower of cost or fair market value. There is no opening under this standard for approval of an acquisition premium, irrespective of whether there is some demonstrated benefit to ratepayers. As discussed by both Staff and the Attorney General, cost generally means net book value; cost cannot also mean net book value plus a negotiated premium or mark-up.[203]

In rebuttal to Consumers' argument that the price for the CMS units is a fair market price because it is the result of a third-party bidding process, the Attorney General counters that the fact that CMS Enterprises submitted its bid through the CRA bidding process does not demonstrate that $530 million is a fair market price, and that, to the contrary, the restrictive criteria for eligibility to bid and the limited participation of eligible gas plants makes it unlikely that a fair market price was set during the CRA bidding process.[204] The Attorney General adds that this remains a transaction between a regulated utility and its affiliate, not a third-party market transaction, despite the intermediary bidding process.

Noting that whether the price to acquire the plants complies with Rule 8(4) is determined by the meaning of "cost," the Attorney General asserts that the "fair, reasonable, and consistent interpretation" of the term "cost" in Rule 8(4) means the "net

---

[202] Id. at 9-11.
[203] Attorney General reply brief, p. 23.
[204] Id., p. 54.

book value of the asset being transferred."[205] Consumer's position that "cost" means the embedded cost of capacity for the asset-buyer is contrary to the plain language of the rule, inconsistent with the interests the rule seeks to advance, and would lead to absurd results.[206]

The Attorney General contends that Consumers' reliance on Commission precedent approving affiliate PPA deals for capacity sales is misplaced in this proceeding because capacity sales are products subject to a different part of Rule 8(4).[207] The Attorney General adds that Consumers' interpretation of Rule 8(4) – that "lower than cost" means "lower than the utility's embedded cost of capacity" – would render the cost side of the Rule meaningless in affiliate transactions to acquire generating assets.[208] Conversely, the Attorney General asserts that interpreting "cost" for asset transfers under Rule 8(4) to mean the seller's net book value of the asset is clear, reasonable, and advances the interests the Code of Conduct seeks to protect.[209]

ABATE also argues that recognizing the full purchase price for the CMS Unit transaction is in violation of the Code of Conduct for affiliate transaction. Ms. York testified:

> The affiliate transaction safeguards (Code of Conduct) are in place to make sure affiliate transactions do not ultimately harm ratepayers from paying too much. The original costs of those gas units is obviously much lower than the purchase price agreed to by Consumers and CMS Enterprises. These affiliate transaction rules are consumer safeguards that must be maintained to protect ratepayers from anticompetitive behaviors from affiliates.[210]

---

[205] Id., p. 56.
[206] Id.
[207] Id., p. 57.
[208] Id., p. 59.
[209] Id., pp. 60-61.
[210] 7 Tr 2828.

Like Staff, the Attorney General, and ABATE, the UCC notes that Consumers argues that "cost" refers to the regulated utility's own cost of providing the product or service produced by the asset, and thus, proposes a comparison between the Consumers' "embedded cost of capacity" and the acquisition price per kW-year for the CMS Units. UCC counters that Consumers' interpretation "conflicts with the text and purpose of Rule 8(4)." The UCC maintains:

> One can see how the Company's interpretation of cost is incorrect by comparing Rule 8(4)'s distinct pricing regime for services or products with its approach to asset transfers. For purchases of services or products from affiliates that are not governed by the MCL 460.10ee(8) provisions regarding value-added products, Rule 8(4) provides that "compensation shall be at the lower of market price or 10% over fully allocated embedded cost." The Company's interpretation would eliminate the meaningful variation between "cost" for assets and "fully allocated embedded cost" for products or services. This difference in phrasing is particularly meaningful because it represents a clarification relative to the Commission's 2001 Code of Conduct, which used "fully allocated embedded cost" for both assets and products or services. Rule 8(4) thus follows the language of even earlier affiliate transaction guidelines established for Consumers in 1989. The current language is sensible: whereas determination of cost for products or services requires some form of cost allocation, costs for assets are specific to the asset, and hence do not require any special allocation.[211]

In response, Consumers argues that its request for recovery of the full purchase price of the CMS plants is governed by the "reasonable and prudent standard," and, as such, the referenced Commission orders do not provide a basis to deny recovery of the full purchase price of the CMS plants.[212] Consumers asserts that the Commission cases referenced by the other parties predate the enactment of Section 6t in 2016, which specifically governs IRPs. Thus, in an IRP case, Consumers argues that the Commission should review the purchase price of the CMS Plants under the "reasonable and prudent"

[211] UCC brief, p. 30 (citations omitted).
[212] Consumers Energy brief, p. 273.

standard of Section 6t, and conclude that the purchase price, including the acquisition premium, is fully recoverable in rates as a reasonable and prudent cost to implement the PCA.[213]

Next, Consumers contends that the Commission does not always require the utility to show a "net benefit" as a condition to receiving approval to recover an acquisition premium in rates. Consumers points out that the Commission has allowed recovery of acquisition premiums in prior cases with no discussion on the record regarding whether customers will receive a net benefit from the acquisition, including Consumers' acquisition of the Zeeland Plant from LS Power Group in Case Nos. U-15245 and U-15645; and DTE Electric Company's acquisition of the Renaissance Power Plant in Case Nos. U-17767 and U-18014.[214]

Finally, Consumers argues that Commission orders on which the Staff and the Attorney General rely are not relevant since the CMS transaction does not present any of the "historical concerns" with acquisition premiums that the Commission discussed in Case Nos. U-9323, U-13808, U-13898, and U-14672.

As noted above, this PFD recommends that if the Commission approves the purchase of the CMS plants, it should nevertheless deny the inclusion of the acquisition premium in any preapproval of costs, because the purchase price violates the Code of Conduct requirement that asset transfers from an affiliate to a utility shall be at the lower of cost or fair market value. As further outlined above, neither the Commission's benefits standard nor the FERC's net benefits formulation for evaluating acquisition premiums

[213] Id.
[214] Id., p. 274-276, citing 7 Tr 1603, 1616.

apply to this transaction. Fortunately, Rule 8(4) of the Code of Conduct squarely addresses the issue.

Staff, the Attorney General, ABATE, and the UCC all maintain that Consumers has not shown that the purchase price for the CMS plants complies with Rule 8(4). These parties argue that "cost" in the context of Rule 8(4) is synonymous with "book price" and "net book value" and, as such, and as the Attorney General argues, cost cannot also mean net book value plus a negotiated premium or mark-up. This PFD agrees.

Consumers counters that "cost" under Rule 8(4) means the utility's embedded cost of capacity, the use of which concept assures that a transaction with an affiliate does not adversely affect the utility's cost structure by causing the cost per unit of service, product, or property to rise above its average or fully embedded cost. However, Consumers' arguments on this point are unsupported in several respects.

First, as Staff notes, Consumers' interpretation violates principles of statutory construction applicable to the Commission's Code of Conduct.[215] Since the term "fully allocated embedded costs" is used in Rule 8(4) to describe the cost of products and services being exchanged between utilities and their affiliates, the term "cost" used later in the subsection to describe the cost of an asset transfer between utilities and affiliates cannot refer to "fully allocated embedded costs."[216] Similarly, the word "cost," which the current Code of Conduct substituted for the phrase "fully allocated embedded cost" in the

[215] *See*, *e.g.*, *General Motors v Bureau of Safety & Regulation*, 133 Mich App 284, 292, 349 NW2d 157 (1984)("In construing administrative rules, the rules of statutory construction apply.")
[216] See, e.g., United States Fidelity Guaranty v. Michigan Catastrophic Claims, 484 Mich 1, 14, 795 NW2d 101 (2009)("Simply put, 'the use of different terms within similar statutes generally implies different meanings were intended.' If the Legislature had intended the same meaning in both statutory provisions, it would have used the same word.")

old Code of Conduct, must be given a different meaning than the phrase it replaced.[217] As UCC argues:

> The Company's interpretation would eliminate the meaningful variation between "cost" for assets and "fully allocated embedded cost" for products or services. This difference in phrasing is particularly meaningful because it represents a clarification relative to the Commission's 2001 Code of Conduct, which used "fully allocated embedded cost" for both assets and products or services.[218]

Second, as Staff also notes, the acknowledged purpose of the Code of Conduct, and the case law requiring administrative rules to be interpreted to accomplish their objectives, support Staff's interpretation of "cost" as that term is used in the current Code of Conduct:

> Using "original cost" or "net book value" as the measure of "cost" in the Code ensures that a utility is not passing on inflated costs to its ratepayers by purchasing an asset from an affiliate for more than it is worth and including this high cost in base rates. By contrast, using the buyer's embedded cost of capacity as the measure of "cost" provides little if any protection to ratepayers.

Defining "costs" as meaning "book price" or "net book value" is consistent with the policies behind the adoption of the Code of Conduct. As the Attorney General notes, when it adopted the affiliate pricing standard in 2000 as part of its Guidelines for Transactions Between Affiliates, the Commission explained that pricing restrictions are needed as these deals are inherently vulnerable to obfuscation and bias:

> Those provisions are a valid expression of a longstanding regulatory standard. Although the provisions are asymmetrical in the sense that they do not treat transfers of property or resources going from a public utility to its affiliate in the same manner as transfers going the other direction, the asymmetry is justified by the need to make it more difficult for utility companies to account for affiliate dealings in a manner that would be

[217] *See, e.g., In Re Childress Trust*, 194 Mich App 319, 326, 486 NW2d 141 (1992)("In construing an amendment of a statute, we presume that a change in phrasing implies an intent to change the meaning as well.")
[218] UCC brief, p. 30 (citations omitted).

> contrary to ratepayers' interests. Even though the subsidiaries, ventures, and affiliates embedded within a utility holding structure usually maintain distinct identities as legal persons, they act as a single firm that serves the collective economic interests of the parent company's investors and management.[219]

Similarly, ABATE argues that the affiliate transaction safeguards in the Code of Conduct are in place to make sure affiliate transactions do not ultimately harm ratepayers from paying too much, and as such must be maintained to protect ratepayers from anticompetitive behaviors from affiliates.

Turning to Consumers' request that the Commission grant a waiver of the Code of Conduct requirements as an alternative to compliance with the Code of Conduct's Asset Transfer Rule, Consumers argues that the granting of the waiver under the Code of Conduct is appropriate because the purchase of the CMS plants will not impair the development or functioning of the competitive market. Consumers reiterates that the acquisition of the CMS plants was the result of "a market-based RFP conducted by an independent third party[,]" and the contract between Consumers and CMS "resulted from an arms-length negotiation," which followed the RFP process. According to Consumers, "Customers benefit from the participation of the Company's affiliate in the RFP, and the potential harm which the Code of Conduct was intended to prevent is not present."[220]

This PFD recommends that the Commission deny Consumers the requested waiver because the company has not demonstrated that a waiver is warranted in this case. Indeed, Consumers' argument is counterintuitive; it argues for a waiver of Rule 8(4) based on its assertion that its request is not contrary to the very rule which bars its

[219] Attorney General brief, pp. 52-53, quoting May 3, 2000 order in Case No. U-11916, p. 10.
[220] Consumers brief, p. 268, citing 4 Tr 714.

request. As UCC notes, the Commission should approve waivers of the Code of Conduct provisions sparingly, otherwise, the adopted regulations will fail to provide appropriate guidance to interested parties. And, as ABATE argues, there is no reason to reject the Code of Conduct requirement that these facilities be sold at cost, which cost would still ensure CMS Enterprises is made whole for its investment. Waiving this requirement and permitting the acquisition at the unnecessarily excessive cost resulting from the acquisition premium, ABATE contends, is unjustifiably and unreasonably detrimental for Consumers' ratepayers. This PFD agrees.

5. Transmission Analysis

In addition to the requirements for transmission analysis contained in MCL 460.6t(5), quoted above, the IRP filing requirements mandate that the IRP include:

> Any information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources.[221]

As part of the settlement agreement in Consumers' last IRP, the company agreed:

> The Company acknowledges that capacity imports can lend support to the Company's PCA and that opportunities to increase the CIL should be evaluated. In addition, the Company acknowledges that the CIL supports the reliability of the transmission system and that an adequate CIL needs to be maintained. The Company shall continue to collaborate with METC and MISO on the implementation of the PCA to minimize negative impacts on the Zone 7 CIL and investigate opportunities to increase the CIL. The Company also agrees to continued collaboration with METC on the implementation of all future PCAs.[222]

[221] December 20, 2017 order in Case No. U-15896, Exhibit A, Section XII(e).
[222] June 7, 2019 order in Case No. U-20165, Exhibit A, pp. 9-10.

With that background in mind, there were several issues raised with respect to the company's transmission analysis and its compliance with Section 6t, the filing requirements, and the settlement agreement.

Mr. Scott testified that Consumers met with METC seven times as part of the IRP process, from January through August 2020, where the parties discussed IRP requirements, the CIL, and transmission alternatives. As a result of these discussions, METC created an IRP Transmission Evaluation (Exhibit A-77) that contains the results of METC's evaluation of future scenarios and potential impacts on the transmission system. The scenarios METC evaluated included: (1) generator additions and retirements in 2031 based on the PCA approved in the previous IRP; (2) retirement of Campbell 1 and 2 by 2024 and 2031; (3) retirement of Karn 3 and 4 by 2024; and (4) retirement of Campbell 1-3 and Karn 3 and 4 by 2025.[223] Mr. Scott discussed assumptions, detailed results (including estimated costs), and limitations of each of the studies,[224] testifying that for the fourth scenario where all Karn and Campbell units are retired by 2025:

> According to METC's report, steady state results identified 11 system issues that require transmission network upgrades as a result of these retirements. Three of the transmission network upgrades have been submitted in the MTEP21 cycle for other reasons. METC determined that the preliminary cost estimate of transmission network upgrades associated with this scenario is $82.1 million, excluding the MTEP21-submitted projects, and $97.2 million including the MTEP21-submitted projects. METC also provided the equivalent revenue requirement associated with this scenario.[225]

[223] 7 Tr 1974-1975.
[224] Id. at 1977-1978.
[225] 7 Tr 1982.

Mr. Scott testified that Consumers found METC's estimate of transmission network upgrade costs to be reasonable.[226] Mr. Scott also discussed interconnection costs and distribution upgrades that were included in the modeling.[227]

Turning to capacity import and export limits, Mr. Scott testified that, in Consumers' modeling, the assumptions used for CIL and capacity export limit (CEL) were based on the most recent public reports from MISO available when the company began modeling. Mr. Scott explained that Consumers assumed a CIL of 3,200 MW, and no limit for CEL, as set forth in MISO's 2020/2021 LOLE report.[228] Mr. Scott noted that MISO had updated CIL since the company developed its IRP, and that for 2021/2022, MISO determined a CIL of 4,888 MW.[229]

Mr. Scott testified that at the Commission's request, MISO performed a CIL/CEL expansion study for MISO Zone 7, in which he and representatives from METC participated. Mr. Scott presented the study in Exhibit A-78. According to Mr. Scott, the MISO study modeled three scenarios in which the CIL for Zone 7 could be increased to 4,700 MW, and up to 6,200 MW, under different assumptions about generation additions and retirements. He also noted that the MISO study included different assumptions about renewables and storage than the company included in the PCA.[230] The results of the study indicated that CIL could be increased to the higher CIL limits in the study with additional transmission projects. However, according to Mr. Scott, there were several limitations to the study, including sensitivity to assumptions about new generator siting;

[226] Id.
[227] Id. at 1983-1987.
[228] 7 Tr 1988.
[229] Id. at 1989.
[230] Id. at 1989-1990.

the study only evaluated CIL on-peak, whereas CIL could be different at other points in time, and additional studies would be needed to confirm estimated transmission project costs and that the proposed projects meet all planning criteria. As such, Mr. Scott testified that the MISO study should be viewed as informational only and that "[t]hese results demonstrate that certain transmission network upgrades could potentially increase CIL. MISO's study results, however, do not definitively demonstrate that increasing CIL is required or economically justified at this time."[231] Mr. Scott added that, based on the results of the MISO PRA from 2014/2015 through 2020/2021, "[o]n a percentage basis, the amount of CIL unutilized for these eight years was 56%, 68%, 56%, 64%, 61%, 95%, 97%, and 64%, respectively. This results in an average unutilized rate of approximately 70% over the eight-year period."[232] Mr. Scott concluded that these results further demonstrate that there is no justification for increasing CIL, noting that although CIL limits the amount of resources that can be imported from outside the zone, "those remote supply sources do not necessarily exist. Even if the Company did contract with external resources, these resources do not provide a complete supply option because external resources can only be counted toward meeting the PRMR and not the LCR."[233]

Ms. Simpson testified that Staff reviewed the filing requirements on transmission and the company's presentation, finding that the company engaged with METC/ITC and MISO to evaluate potential new or upgraded transmission solutions, including meeting with METC/ITC outside of the MISO transmission planning process. Referencing Mr. Scott's testimony and Exhibit A-77, Ms. Simpson testified that Staff supported the

[231] Id. at 1992.
[232] Id. at 1993.
[233] Id. at 1994.

METC/ITC analysis as informative and reasonable, with the caveat that the assumptions underlying the study, including generation retirements and additions, siting, load forecast, and costs could change.[234] In future IRPs, Staff recommends that Consumers continue to work with METC/ITC to determine if the transmission system could benefit from the connection of DERs.

Ms. Simpson explained that Consumers complied with the Commission's filing requirements for transmission, as well as with the requirements under MCL 460.6t(5)(h)(a)-(e), noting that the company presented an analysis of Iowa wind that could be imported into Zone 7. However, in the company's next IRP, Ms. Simpson recommended:

> With regard to subsections MCL 460. 6t(5)(h)(e)(2), the Staff would like the Company to provide more analysis of the cost of Power Purchase Agreements (PPAs) and transmission costs from neighboring RTOs, from other MISO local resource zones, and from Ontario's Independent Electricity System Operator (IESO) in the next IRP to verify that those resources are either more or less expensive on a $/kW than what is contemplated in the Company's future IRP filings. With regard to subsections MCL 460. 6t(5)(h)(e)(3) and (4), Staff would like Consumers and METC/ITCT to provide more analysis on these two sections in the next IRP filing on increasing system efficiency, reducing line losses, and advancing transmission network technologies that can affect supply-side and demand-side resources.[235]

Ms. Simpson added that, with respect to transmission upgrade and transmission interconnection cost assumptions in modeling:

> Staff would recommend that the Company utilize METC/ITCT estimates for interconnection of new resources for future modeling. The reason is that the analysis that the METC/ITCT conducted was developed in cooperation with the Company. However, since the Company used a single number for generation interconnection, the choice of which number would not likely have a significant impact on new resource selections but may impact

[234] 8 Tr 3694-3695.
[235] 8 Tr 3700-3701.

> retirement analyses. Also, part of developing these scenarios, the Company in cooperation with METC/ITCT should determine where the transmission system is most likely to be able to host new generation resources. In other words, there should be some effort to determine where new generation resources can be interconnected to either provide the lowest cost or the most bene fit to ratepayers. At this time and for the purpose of modeling resources with the limited available data, Staff finds that the interconnection cost assumptions used by the Company are reasonable.[236]

Mr. Doherty testified that the company's assumption of a CIL of 3,200 MW was reasonable, although Consumers' assumption was the lowest CIL for Zone 7 over the past decade. Mr. Doherty observed that the CIL is volatile and future CILs are difficult to project. Nevertheless, Consumers used the most recent CIL available at the time it began its modeling. Mr. Doherty noted that Consumers assumed that the full 3,200 MW of CIL was available for the company, even though there are several utilities in LRZ 7 that share the CIL.[237]

On behalf of METC, Mr. Marshall described the role of transmission in resource planning, testifying that METC has evaluated the upgrades and transmission changes needed for the execution of Consumers' PCA to ensure reliability.[238] Mr. Marshall discussed the development and execution of the Thumb Loop project, highlighting it as an example of how transmission can enable generation planning and support the transition to clean energy resources.[239] He also discussed the benefits of the long-range transmission planning (LRTP) process for evaluating multi-value transmission projects (MVPs) through MISO, which include addressing thermal and voltage issues, enhancing CIL and CEL, reducing congestion, providing for the regional transfer of generation

[236] 8 Tr 3701-3702
[237] 8 Tr 3482.
[238] 7 Tr 2549.
[239] Id. at 2551-2553.

resources, and facilitating the interconnection of large amounts of renewables, among other things.[240]

Turning to the company's IRP and PCA, Mr. Marshall testified that the proposed acquisition of gas plants, solar, and more demand-side resources, as well as the retirement of the Karn and Campbell units, will have impacts on the transmission system, which were analyzed by ITC.[241] According to him, the ITC analysis found that CIL remains constrained at less than 4,000 MW, indicating, "that the PCA may not have a material impact on the LRZ 7 CIL but it should be noted that the changes in the PCA do dramatically limit the ability for redispatch that can help optimize the use of existing transmission to maximize the CIL."[242] Mr. Marshall also suggested that Consumers evaluate locations throughout Michigan where generator interconnection will not require significant network upgrades, to more efficiently execute the PCA, and he emphasized that investments in local resource development should be balanced with regional transmission investments, especially given the company's increased investment in renewables.[243]

Mr. Marshall disagreed with Mr. Scott's contention that "there is an abundance of CIL" in Zone 7 that is not being used to meet PRMR, explaining that a portion of the CIL Mr. Scott claimed was available is actually used to meet local reliability requirements (LRR), pointing out that, "[i]n order to meet NERC reliability standards and avoid clearing at Cost of New Entry (CONE), the Zone's internal Zonal Resource Credits (ZRCs) plus

[240] Id.at 2553; Exhibit METC-2.
[241] 7 Tr 2556-2557; Exhibit A-77.
[242] Id. at 2557.
[243] Id. at 2557-2558.

CIL must meet or exceed the Zone's LRR"[244] Mr. Marshall explained that the LRR "represents the amount of internal capacity (resources located within a zone) that a LRZ would need to secure to meet its risk-adjusted non-coincident peak demand as if it were an island."[245] He added that the LRR is used to calculate the LCR (LCR=LRR-CIL) and that if a zone does not have sufficient capacity to meet its LRR, the zone will automatically clear at CONE (approximately $250 per MW-day) in the PRA, indicating that the zone does not meet NERC reliability standards.[246] Mr. Marshall testified that Zone 7 cleared at CONE in 2020/2021, the only zone to do so, and that Zone 7 is at risk of doing so again in the 2022/2023 PRA due to transmission constraints and thermal plant retirements.[247]

Mr. Marshall testified that, as outlined above, and contrary to Mr. Scott's claim, it is necessary to increase CIL at this time. According to him, in addition to the fact that all of CIL is being used to meet reliability requirements, it takes several years to build out transmission, the State's generation mix is changing rapidly, and MISO is petitioning the FERC to change to a seasonal, rather than annual, resource adequacy construct, which will put additional pressure on CIL.[248]

Finally, Mr. Marshall made four recommendations for ensuring that sufficient transmission resources are available to support the PCA:

- Increase the LRZ 7 CIL to lower the dependency on the increasingly concentrated LRZ 7 resources that result in lower reliability and higher capacity and energy prices.

- Support MISO's implementation of an annual forward-looking PRA on a five year out basis with supply assumptions that align with its annual Regional Resource Assessment.

[244] Id. at 2560.
[245] Id.
[246] Id.
[247] Id. at 2562-2563.
[248] Id. at 2564-2565.

- Include an evaluation of broad-ranging extreme events that might result in outages of significant portions of the generation or transmission systems in transmission and other resource planning.

- Foster increased transparency of the distribution system, including aggregations/behind-the-meter generation, as accounting for the significant changes on the distribution system will become increasingly essential for the reliability of the [bulk electric system] BES. As part of the transparency, information on the size and location of both Demand Response and Distributed Energy Resource Aggregation resources, which may be comprised in part of Demand Response, connected at the distribution level would be beneficial.[249]

On behalf of MNS, Mr. Caspary highlighted the importance of transmission in terms of flexibility and access to high quality renewable resources in other zones to help address system requirements, noting that there are challenges to the transmission system including aging facilities and barriers to building new transmission corridors.[250] Mr. Caspary further discussed the importance of regional and interregional collaborative planning in addressing the displacement of traditional generation with renewable energy and demand-side resources and to ensure reliability and resilience of the bulk power system. Specifically addressing Consumers transmission analysis, Mr. Caspary testified that the analysis should have been more rigorous, particularly with respect to importing wind resources, and identifying areas of available transmission capacity, adding that the company should undertake transmission planning as part of its IRP to optimize the benefits of least-cost planning.[251]

Next, Mr. Caspary detailed the need for expanded transmission, citing sharply reduced costs for renewables leading to significantly more penetration of wind and solar,

[249] Id. at 2569.
[250] 8 Tr 3101-3102.
[251] 8 Tr 3103-3104.

reduced costs resulting from diversity of supply, enhancing the value of renewable energy, increasing the reliability and resilience of the bulk power system, protection against increasingly common extreme weather events, and risk mitigation, among other benefits.[252]

Turning to his evaluation of Consumers' transmission analysis, Mr. Caspary reviewed the statutory and regulatory requirements for transmission consideration in IRPs, as well as the requirements set forth in the settlement agreement in Consumers' previous IRP.[253] Mr. Caspary testified that it did not appear that Consumers evaluated any opportunities to increase CIL, pointing to Mr. Scott's conclusions about the two CIL/CEL expansion studies. Mr. Caspary disputed Mr. Scott's reasoning that, because the LCR for Zone 7 is 1,749 MW less than PRMR and the 1,749 MW difference is less than CIL for Zone 7, no additional import capacity is required. Mr. Caspary testified that this was erroneous for two reasons. First, according to him:

> [U]nder MISO rules, the LCR is the Local Reliability Requirement minus the Zonal Import Ability (ZIA). The ZIA determines the CIL after accounting for exports to non-MISO load. Therefore, all other things equal, increasing the CIL will lower the LCR. Lowering the LCR will increase the difference between the PRMR and the LCR. Therefore, increasing the CIL will allow the use of more imports to meet the PRMR, under Consumers witness Scott's own reasoning.[254]

Second, Mr. Caspary contended that Mr. Scott only considered resource adequacy in determining that increasing CIL was not economically justified, and the company did not evaluate access to lower-cost energy. Mr. Caspary cited the company's evidence that out-of-state wind had the lowest LCOE of all of the resources the company considered,

[252] 8 Tr 3107-3117.
[253] 8 Tr 3118-3119.
[254] 8 Tr 3121-3122.

including assumed out-of-state wind PPA prices of $29 per MWh, that energy prices in Iowa are projected to be $4.77 lower than prices in Michigan, and that wind capacity factors in Iowa are assumed to be 44.4%, compared to wind capacity of 29% in Michigan.[255]

Mr. Caspary took issue with Mr. Scott's statement that while transmission could move remote supply into Zone 7, "those sources of supply do not necessarily exist," observing that Consumers did not investigate any supplies outside of Zone 7 in its RFPs since the company's last IRP.[256]

Based on his review and evaluation of Consumers' transmission analysis, Mr. Caspary recommended that the Commission find that the company has not met the requirements of Section 6t, and Consumers should be directed to undertake a new transmission analysis consistent with his recommendations.[257]

In rebuttal, Mr. Scott disagreed with Staff's recommendation that in future IRPs, the company should use METC's cost estimates for transmission network upgrade costs, testifying that the $144 per kW cost estimated by METC for interconnection of new resources "was based on a number of assumptions in the year 2032 including system topology, load forecasts, and generator siting[,]" asserting that costs from the company's recent RFPs were significantly lower and that it would be unreasonable to assume that METC's higher cost assumption would occur for every project from now until 2032.[258]

In response to Staff's recommendation that the company provide an evaluation of PPAs from outside Zone 7, Mr. Clark explained that it is unclear if resources from IESO

---

[255] Id. at 3122.
[256] Id. at 3123.
[257] Id at 3124.
[258] 7 Tr 2015.

would qualify as an external resource under MISO's requirements, adding that he was not aware how MISO resources outside of Zone 7 could be counted toward LCR or PRMR, adding that locating generation resources in Zone 7 presents a better economic opportunity.[259]

In response to Mr. Marshall's discussion of the LRTP process, Mr. Scott testified that overall, the LRTP and evaluation of MVPs is performed on a regional basis, and he agreed that some of the benefits Mr. Marshall cited could be provided. However, he observed that the LRTP is at a preliminary stage and the entity most appropriate to evaluate MVPs is MISO, noting that only MISO staff can submit projects for evaluation. Given that, Mr. Scott opined that the company's IRP proceeding is not the appropriate forum to discuss the LRTP or potential MVPs.[260]

With respect to Mr. Marshall's and Mr. Caspary's approaches to calculating or otherwise assessing CIL, LCR, LRR, PRMR, and the PRA, Mr. Scott disputed that these witnesses had necessarily defined or applied these terms correctly (i.e., in the same manner as MISO), admitting that at times their calculations were mathematically correct, but only under very specific scenarios. He further noted CIL, LCR, PRMR and LRR can each change independently in a given year due to factors beyond the company's or METC's control.[261]

Mr. Scott testified that Mr. Marshall did not provide an economic analysis to show that excess resources would result in reliability benefits that exceed the cost of those resources, nor did he demonstrate that CIL would need to increase to ensure resource

[259] 5 Tr 1152-1153.
[260] Id. at 1999-2002.
[261] 7 Tr 2003-2008; 2012.

adequacy, noting that Consumers demonstrated that resource adequacy can be met with internal resources and no increase in CIL.[262] According to Mr. Scott, Mr. Marshall did not identify or analyze any specific MVP or MISO CIL/CEL expansion projects that would increase CIL in Zone 7, nor did he identify a need to increase CIL under NERC Transmission Planning Standards. He added that benefits like geographic diversity, access, and delivery can be attained without the addition of transmission.[263]

Similar to his response to Mr. Marshall, Mr. Scott testified that Mr. Caspary failed to provide an assessment of any specific projects that justify an increase in CIL or that contradict the company's position that resource adequacy can be met with internal resources. Mr. Scott added that Mr. Caspary failed to demonstrate that CIL should be increased based on NERC Transmission Planning Standards.[264] Mr. Scott opined that Mr. Caspary's statements concerning increasing CIL to provide access to lower cost energy were general and no economic evaluation was provided.

In its brief, Consumers relies on the testimony of its witnesses, emphasizing that an increase in CIL is not necessary to meet reliability standards and that local capacity resources can be used to meet local load. Citing testimony by Mr. Clark, Consumers maintains:

> DTE and Consumers Energy's bundled load represents approximately 85% of LRZ 7 planning requirements. Given that both DTE and Consumers Energy are regulated utilities under the jurisdiction of the MPSC whose service territories are located 100% within LRZ 7, a reasonable assumption is that about 85% of resources used to meet planning requirements will be located within LRZ 7. Under this assumption there is no need to have a CIL greater than 15% of the planning requirements. This would be equivalent to ~3,500 to 4,000 MW of import capability.[265]

[262] 7 Tr 2008-2009.
[263] 7 Tr 2009-2010.
[264] 7 Tr 2013.
[265] Consumers brief, p. 215, citing 5 Tr 1146.

Consumers argues that Mr. Marshall's claim about the risk of Zone 7 clearing at CONE in the 2022/2023 MISO PRA was presented without support, and even if Zone 7 does clear at CONE, the economic impact on Consumers would be small. Consumers dismisses the remainder of Mr. Marshall's claims regarding reduced reliability as presented "[with] little evidence to support them beyond his opinion."[266]

In response to MNS, Consumers disagrees that the company did not give appropriate consideration to out-of-state resources, pointing to Ms. Walz's testimony and Exhibit A-13 to demonstrate that out-of-state wind "is not predominately economic in the 20-year planning horizon."[267] Responding to both Mr. Caspary and Mr. Marshall's discussion about MISO's LRTP initiative, Consumers reiterates Mr. Scott's testimony that the LRTP is a MISO activity, the results of which have not been released.[268] And Consumers urges the Commission to reject Staff's recommendation to further evaluate the cost of PPAs from areas outside of Zone 7, for the reasons stated by Mr. Clark.

Staff asserts that Consumers transmission analysis met the statutory and IRP filing requirements, presenting recommendations for Consumers next IRP:

1. Staff recommends the Company continue to work with ITC and METC to determine where the transmission grid could benefit from the connection of distributed energy resources and include that analysis as part of its next IRP.

2. Staff recommends that the Company work with METC and ITCT to determine where the transmission grid could benefit from the connection of distributed energy resources and include that analysis as part of its IRP.[269]

[266] Consumers brief, p. 217.
[267267] Id. at 220, citing 3 Tr 314.
[268] Consumers brief, pp. 416-417.
[269] Numbers 1 and 2 appear to be the same.

3. Staff recommends that the Company provide further analysis of the cost of PPAs and transmission costs from neighboring RTOs or other MISO resource zones and Ontario's Independent Electricity System Operator (IESO).

4. Staff recommends that the Company utilize METC and ITCT interconnection costs for new resources in future IRPs. (8 TR 3695, 3700-3702).[270]

While acknowledging the interplay between transmission and distribution, Staff contends that Mr. Caspary's recommendations "seem to be aimed at repeating the transmission planning process currently performed at an RTO level in the Company's IRP."[271] Staff disagrees with MNS that the process described by Mr. Caspary is appropriate as part of an IRP, although, "Staff does support iterative planning where the results from each planning process are continuously fed into another. Staff believes that this is the only way to co-optimize distribution and transmission planning effectively at this point in time[,]"adding that "Mr. Caspary's analysis is faulty because it is hinged on activities that are performed as part of RTO planning processes and applies recommendations that simply cannot be performed by the utility as described."[272]

Quoting Mr. Marshall's testimony, METC avers:

> Consumers' PCA, combined with the State's broader policy objectives, requires that action be taken now to increase CIL levels to maintain the reliability of the bulk electric system (BES). First, as mentioned above, all LRZ 7 CIL is being used already. Second, MISO's PRA [Planning Resource Auction] only provides a one-year outlook for capacity planning positions. However, new transmission and generation build-out can take up to four or more years for each facility and even longer for whole portfolios of facilities. Third, similar IRPs from Michigan Load Serving Entities (LSEs) describe a rapid and drastic shift in the State's capacity resources. The displacement of 1.8 gigawatts (GW) of coal thermal resources with renewable and behind-the-meter resources by 2025 will likely put upward pressure on future LRRs.

[270] Staff brief, p. 124.
[271] Id.
[272] Id. at 125.

> The retirement of coal units and lack of new dispatchable thermal generation in and around LRZ 7 could put downward pressure on future CIL levels unless the necessary transmission investments are made. The combined effect of putting upward pressure on LRRs and downward pressure on CILs explicitly results in a less reliable grid and/or higher costs for capacity. (7 Tr. 2563-2564.)[273]

METC argues that because reliability applies to the zone, and not to individual distribution utilities, increasing CIL would increase flexibility, support reliability in Zone 7, and reduce exposure to price variability. Contrary to Consumers' dismissal of Mr. Marshall's concern that Zone 7 could again clear at CONE, "METC also recognizes that a deficient planning reserve margin—that results in the MISO PRA clearing at CONE—does not merely result in an economic impact. Not meeting the requirements of resource adequacy raises larger red flags regarding reliability—it is a real signaling metric used by MISO to create real market and infrastructure build-out effects."[274] METC also points to recent extreme weather events that have caused grid failures, despite robust reserve margins, adding that "METC does not agree that there is no incremental or material benefit to increasing the CIL. A robust CIL is a cost-efficient way to access resources during extreme scarcity, and ensure that LRZ 7 does not become further bifurcated from MISO for everyday operations."[275]

METC points out that although Consumers requested that it perform an assessment of the transmission system, the company nevertheless disregards METC's analysis and recommendations. METC also points out that Consumers CSA assumes that the company may use the entire 3,200 MW of CIL, despite the fact that CIL is allocated on a pro rata basis. According to METC:

---

[273] METC brief, pp. 10-11.
[274] Id. at 12.
[275] Id. at 13.

> Stated another way, the Company's reliability modeling indicates it needs access to 3,200 MW of CIL in order to meet MISO Resource Adequacy Requirements. This level of import reliance assumes LRZ 7 as a whole has a CIL of roughly 8,000 MW. At the same time, the Company argues that further investment in LRZ 7's existing 3,749 MW CIL is not needed.[276]

METC concludes that as the owner and operator of the transmission system, it is in the best position to assess and address reliability concerns, and the Commission should give significant weight to Mr. Marshall's analysis of the need to invest in transmission now.

MNS asserts that Consumers did not meet the transmission-related requirements in Section 6t, the IRP filing requirements, or the settlement agreement in Case No. U-20165. MNS contends that Consumers: (1) used outdated assumptions for CIL; (2) the company failed to assess options for increasing CIL; and (3) it failed to evaluate or pursue PPAs from other zones or regions.[277]

Relying on Mr. Caspary's testimony, MNS recaps the benefits of transmission, emphasizing the need for expanded import capability to support increasing renewables, reliability, and resilience. Turning to its main point, that the company's transmission analysis was not compliant, MNS quotes the PFD and order in DTE Electric's IRP, Case No. U-20471, wherein the Commission found that DTE's failure to consider resource options outside of Zone 7 did not comply with MCL 460.6t(h), (j), and (k), directing the company to provide a transmission analysis containing "a full suite of options, including renewable energy imports, transmission limits and transmission growth opportunities, and ways to optimize the utility's portfolio to reduce risk and improve cost-effectiveness."[278]

---

[276] Id. at 15.
[277] MNS brief, pp. 122-123.
[278] MNS brief, p. 128 quoting February 20, 2020 order in Case No. U20471, p. 83.

MNS contends that Consumers was on notice that the use of an outdated CIL was not acceptable, citing the April 27, 2018 order in Case No. U-18419, p. 111, where the Commission admonished DTE Electric for relying on outdated material in its application for a certificate of need. According to MNS, Consumers failed to justify the use of a 2019 report for CIL for inputs to all of its modeling, and it failed to explain why it could not have updated its models using the 2020 CIL determination, or at least run additional sensitivity analyses using updated numbers.[279]

Next, MNS argues that Consumers failed to evaluate opportunities to increase CIL in Zone 7, noting that Consumers dismissed the MISO Zone 7 CIL/CEL expansion study as "informational," despite the fact that the study identified projects that could increase CIL up to 6,200 MW in certain scenarios. According to MNS, if the requirement for Consumers to evaluate opportunities to increase CIL can be met by mere participation as a stakeholder in the development of a CIL study, with a subsequent dismissal of the results of that study, then the requirement is meaningless.[280]

MNS points out that Consumers' primary justification for rejecting investment to increase CIL lies in the fact that the LCR for Zone 7 is 1,749 MW less than the PRMR, thus only 1,749 MW of imports would be needed to satisfy the PRMR, considerably less than the existing CIL for the zone. So, Consumers reasons that increasing the CIL is unnecessary.[281] MNS argues that Mr. Scott's formulation is incorrect, and that both Mr. Caspary and Mr. Marshall provided correct analyses demonstrating that, all other things being equal, increasing CIL will lower the LCR.[282] In response to Mr. Scott's rebuttal that

[279] MNS brief, p. 130.
[280] Id. at 131.
[281] Id.
[282] Id. at 132, citing 8 Tr 3122 and 7 Tr 2561.

Mr. Caspary's formulation was "mathematically true" but that a number of factors outside the company's, METC's or the Commission's control could impact CIL or LRR, MNS avers that this "is insufficient to justify Consumers' refusal to evaluate opportunities to increase the CIL as required for an IRP transmission analysis," adding that "increasing the CIL is one way to address the LCR that Consumers (and DTE) spend so much time in these cases trying to scare everyone about."[283]

Finally, MNS contends that Consumers focused only on resource adequacy, failing to evaluate the potential benefit of importing lower-cost energy into Zone 7, reiterating Mr. Caspary's testimony that Consumers' evidence strongly indicates that energy prices in other MISO zones are significantly lower than in Michigan. MNS characterizes as irrelevant Mr. Scott's rebuttal that MISO does not consider the cost of energy resources in its CIL calculations, noting that the Commission has already rejected the notion that transmission analyses in IRPs should be limited to MISO studies. MNS also dismisses Consumers claims that in-state resources avoid transmission congestion or transmission delivery charges, noting that the company's modeling of the cost of out-of-state wind was based on the cost of company-owned wind, and did not analyze the economics of a PPA for wind outside Zone 7.[284]

In reply, Consumers points out that Staff found that the company met the requirements under Section 6t, the IRP filing requirements, and the settlement agreement, and the MNS's claims to the contrary should be rejected. Consumers quotes

---

[283] MNS brief, pp. 132-133.
[284] Id. at 134-135.

language from Staff's brief stating that the analysis that Mr. Caspary calls for is outside the company's abilities and, in any event, is already undertaken by MISO.[285]

In its response to METC, Consumers expresses surprise at the "tenor" of METC's brief, contending that the company worked in good faith with METC throughout the IRP process, and the company incorporated METC's transmission analysis in its modeling.[286] Consumers adds that it does not solely rely on local resources in the IRP, contending that METC's concerns are largely related to the transmission company's pecuniary interest, alleging that, "[u]nfortunately, METC continues to use the Company's IRP proceeding as a platform to advocate for its own business interests despite METC's own analysis showing that the impact of the Company's PCA on the LRZ 7 CIL is immaterial and providing no specific reasons that the Company's PCA should not be approved."[287]

The PFD finds that Consumers complied with MCL 460.6t(5)(h), which requires the company to include "[a]n analysis of potential new or upgraded transmission options for the electric utility" as part of its IRP. This analysis is contained in Exhibit A-78. The PFD further finds that the company's presentation of Exhibit A-77 comported with the filing requirements, which requires the IRP to include "[a]ny information provided by the transmission owner(s)" with respect to options for increasing CIL or CEL, that might facilitate PPAs, or increase system efficiency. However, the PFD agrees with MNS that Consumers did not comply with the settlement agreement in Case No. U-20165, which requires more than simply including information provided by others as part of its filing. Paragraph 10 of the settlement agreement in U-20165 specifically addresses CIL and

[285] Consumers reply brief, p. 250.
[286] Id. at 250-251.
[287] Id. at 251.

requires the company (not METC or other parties) to both "[evaluate] opportunities to increase the CIL" and "investigate opportunities to increase the CIL," neither of which were done here.[288] As MNS points out, the totality of Consumers' "evaluation and investigation" of CIL involved the company's participation in an MPSC-commissioned study on CIL expansion, the results of which the company dismissed as "informational."[289] Consumers did not undertake an economic analysis of any of the options

The central problem with the company's transmission analysis, or lack thereof, appears to be Consumers' starting point assumption that, given the company's intention to retire significant capacity, it faced a binary choice to acquire new capacity in Zone 7, or it could import capacity from elsewhere in MISO or other regions. Of course, the MISO and NERC reliability requirements mandate that a significant amount of capacity be located in Zone 7, but the remainder of the company's capacity needs could have, and should have, been optimized as part of the company's modeling, evaluating the costs of transmission expansion or upgrades as well as the benefits of the additional flexibility and potential access to lower-cost capacity. To be fair, the company's PCA might still have been the most economical choice, but the Commission will never know because the analysis was never performed.

Consistent with the discussion above, the Commission should find that Consumers' transmission analysis did not comply with the settlement agreement. In addition, the Commission should require Consumers, consistent with the Commission's

[288] Paragraph 13.d. of the settlement similarly provides that "the Company's next IRP shall include . . . (i) an analysis of the PCA's impact on the Zone 7 CIL . . . as well as investigating opportunities to increase the CIL and investigating transmission alternatives to improve market access." Consumers did comply with ¶ 13.d.(i).

[289] It should be noted that the existence of this report is indicative of the Commission's concerns about CIL and its role in ensuring reliability and reducing costs in Zone 7.

directions set forth in the February 20, 2020 order in Case No. U-20471, pp. 82-83, to "provide the Commission with an examination of the full suite of options, including renewable energy imports, transmission limits and transmission growth opportunities, and ways to optimize the utility's portfolio to reduce risk and improve cost effectiveness[,]" in the company's next IRP.[290] In addition, the Commission should adopt Staff's and METC's recommendations for further collaboration and additional studies to be presented in future IRPs.

E. Demand Side Resources

1. Energy Waste Reduction

As Consumers outlines in its brief, the company first began offering EWR programs in 2009, realizing energy savings of 0.3% that year, increasing to 1.5% per year beginning in 2017, and 1.8% in 2020. Consumers states that it is targeting 2.0% energy savings in 2021.[291] In developing its EWR savings for the IRP, Mr. McLean testified that Consumers assumed incremental EWR savings of 2% of the previous year's sales for 2021-2023, and 1% for 2024-2040.[292] According to Mr. McLean, "[t]he Company chose the levels included in the PCA based on a combination of factors including historical program performance, the EWR savings levels included in the IRP in Case No. U-20165, the results of recent market potential studies included in the U.S. Department of Energy ("DOE") energy efficiency catalog, and the Electric EWR Potential Study developed by Cadmus[.]"[293] According to Mr. McLean, for 2021-2040, "the PCA includes 8,959,100 MWh of cumulative EWR achievable potential, which represents 21.57% savings relative

[290] Emphasis supplied.
[291] Consumers brief, pp. 73-74; 7 Tr 1880.
[292] 7 Tr 1882; Exhibit A-80.
[293] 7 Tr 1882-1883 (fn omitted).

to the baseline forecast[,]" which is well within the range of values documented in the DOE database of energy efficiency potential studies.[294] Mr. McLean cautioned that potential studies are forecasts and as such, there are risks in both assumptions and program execution that may prevent the company from achieving its targets. Because of these risks and uncertainties, Mr. McLean testified that Consumers' projections for EWR savings are reasonable and achievable, but the company will continue to evaluate and make adjustments to energy savings goals in EWR cases and future IRPs.[295]

Mr. McLean testified that the company requests approval of all incremental EWR investments and expenses for July 1, 2022 through June 30, 2025, including incremental O&M for 2024 and six months of 2025 of $119.5 million; base outlook O&M for 2024, and six months of 2025 of $107.2 million; and a financial incentive for 2024 and six months of 2025 of $45.3 million.

Ms. Smith testified that Staff has some concerns with the EWR amounts included in Consumers' PCA. Acknowledging that the basis for the company's estimates, primarily various energy efficiency potential studies, is reasonable, Ms. Smith testified that it is important to note that these types of studies tend to be conservative and may underestimate actual energy efficiency potential. In addition, Consumers' use of historical EWR program performance is not necessarily indicative of the future. Ms. Smith testified that Staff recommends the use of the Michigan Energy Measures Database (MEMD) as a more accurate and reliable means to forecast energy savings on the basis of actual energy efficient products or systems.[296]

---

[294] Id. at 1883.
[295] Id. at 1884.
[296] 8 Tr 3708-3709.

Ms. Smith noted that since the company's first IRP, Consumers has increased its EWR target from 1.5% to 2%, and that Mr. McLean expressed confidence that, despite challenges, Consumers can attain at least 2% EWR savings. She noted that in Consumers 2022-2025 EWR plan case, Case No. U-20875, the company projects EWR savings of 2.1%.[297]

Mr. Proudfoot explained that, in general, Staff recommends that O&M expenses be scrutinized and approved in more focused proceedings. According to him, DR reconciliation proceedings, REP and REP reconciliations, and EWR plan and reconciliation cases allow for a more detailed review of capital costs and provide context for O&M expense requests.[298] In addition, with respect to EWR costs specifically, Mr. Proudfoot explained that all projected costs and savings from EWR programs, including incentives, should be included in the modeling of EWR so that optimum levels of EWR are selected. However, because EWR programs may change as they develop, actual approval of all costs should be addressed in EWR plan and reconciliation cases, consistent with the process outlined in 2016 PA 342 (Act 342)

Mr. Proudfoot discussed demand-side cost approvals in IRPs in general, explaining that based on the references to "investments" in Section 6t(11), the costs that may be approved as part of an IRP are capital costs, which are long term investments that the company makes in its system. Mr. Proudfoot testified that the statute does not reference costs that would be considered expenses, explaining:

> Staff has based its recommendation to only pre-approve capital costs incurred within the first 3-years after the Commission's Order approving an IRP because of the inherent characteristics that differentiate capital

[297] Id. at 3709.
[298] 8 Tr 3400.

> expenses from O&M expenditures. Capital expenses are, at their core, investments because they are an expense a business incurs to create a benefit into the future. As a result, capital costs are typically collected over an extended period of time commensurate with the expected life or usefulness of the investment. This is significantly different than O&M that is incurred during the normal day-to-day operation of business and recorded on the Company's income statement in the period they occur.[299]

Mr. Proudfoot added that the lack of approval of O&M expense in an IRP does not put the company at risk, given the regularity with which Consumers files rate cases. Mr. Proudfoot testified that, "[s]ince O&M carries with it more uncertainty, it is Staff's position that O&M be reviewed and approved in the context of a general rate case where all other day-to-day operational costs are also detailed. This allows the Commission to understand the expenses associated with the Company's operational needs as a whole rather than in a piecemeal fashion."[300]

Dr. Dismukes testified that he has concerns about the EWR spending amount Consumers proposes compared to the benefits of EWR savings. Dr. Dismukes explained that the company requests approximately $272 million in EWR costs for 2024 and the first six months of 2025, to achieve 545,305 MWh, and 879 MW, of energy and capacity savings. According to Dr. Dismukes, this equates to a cost of nearly $500 per MWh and $309 per kW savings, compared to the LCOE for new generation of $51-$305 per MWh and levelized cost of capacity of $137 to $374 per kW. Dr. Dismukes testified that this makes EWR a more expensive source of energy and capacity than most of the supply-side resources the company is considering. In addition, based on a similar calculation of projected costs divided by savings, Dr. Dismukes found that EWR programs were

[299] Id.
[300] Id. at 3416.

significantly less cost-effective than CVR and DR.[301] Although the Attorney General did not propose a disallowance of any demand-side programs, he recommended that the Commission scrutinize non-program spending (i.e., evaluation and measurement and FIM) to ensure that the company's demand-side programs provide net benefits to ratepayers.[302]

Mr. Neme reviewed Consumers' EWR targets in its PCA, noting that had the company included energy savings from pilot and education programs, the level of savings in 2022 and 2023 would be 2.20% decreasing to between 1.78% and 1.94% from 2024-2030.[303] Mr. Neme noted that although Mr. McLean characterized energy efficiency as low cost and cost effective, Ms. Walz described energy efficiency as a marginal resource compared to other options. According to Mr. Neme, Ms. Walz based her conclusions on "different IRP scenario runs [that] are applicable only to the last increment of efficiency included in the Company's PCA. The base levels of efficiency that Consumers included in every scenario, which represent a large majority of the total EWR savings analyzed in the IRP, are generally more cost-effective than the last increment considered."[304]

Next, Mr. Neme testified that the company undervalued energy efficiency savings by failing to include the benefits EWR provides in terms of avoided T&D investments. And, although the company's modeling included the costs of EWR programs through 2040, the modeling did not account for energy savings that persist after 2040. Finally,

---

301 7 Tr 2115-2116.
302 Id. at 2117.
303 8 Tr 3074.
304 Id. at 3076 (fns omitted).

Consumers grossed up customer energy savings at generation using average, rather than more accurate marginal line loss rates.[305]

Mr. Neme explained that although Consumers did consider some avoided costs for generation interconnection, it did not analyze avoided T&D costs that are typically included in EWR planning and reconciliation proceedings. According to Mr. Neme:

> [E]nergy efficiency and some other distributed energy resources can defer or avoid capacity upgrades to elements of the T&D system whose capacity constraints are completely independent from generation capacity needs. For example, if peak demand growth without efficiency programs would require the capacity of a substation to be upgraded, and if systemwide EWR programs are expected to lower that localized demand growth enough to defer or eliminate the need to upgrade the substation's capacity, those EWR programs will result in an avoided T&D cost.[306]

Mr. Neme calculated that the incremental value of avoided T&D costs in Consumers' PCA was approximately $40 million through 2040, based on the avoided T&D costs the company used in its EWR plan filed in Case No. U-20875.[307]

Next, Mr. Neme explained that although Consumers' EWR modeling captures program costs through the end of the plan period, the benefits that accrue beyond 2040 are not included. In response to discovery, Ms. Walz indicated that excluding post-2040 EWR savings would in fact bias NPV cost calculations. Mr. Neme estimated that the NPV of post 2040 EWR savings is $100 million or more.[308]

Finally, Mr. Neme explained that Consumers assumes that 7.73% of power generated is lost though line losses, based on the company's average line loss rate. According to Mr. Neme, because line losses increase exponentially with load, it is more

[305] 8 Tr 3076-3077.
[306] 8 Tr 3078.
[307] Id. at 3079.
[308] Id. at 3080, 3082; Table 1.

appropriate to use marginal, rather than average, line losses, because energy efficiency savings occur on the margin. Mr. Neme calculated that using marginal line loss rates to calculate EWR savings would increase the value of energy savings by $50 million.[309] Mr. Neme testified that the combined effect of his three adjustments results in $196 million in EWR savings that were not accounted for in the company's modeling, making EWR a much more cost-effective resource than the company presented in the scenarios included in its IRP.[310]

On behalf of ABATE, Ms. York testified that 2008 PA 295 does not require the Commission to award an FIM for EWR performance, although the Commission has done so since 2009.[311] Ms. York testified that although Consumers did not provide the exact calculation of the EWR FIM of $45.3 million, it appears that it was based on the legislative maximum of 20% of the company's proposed EWR investment.[312] Ms. York noted that FIM revenue has more than doubled since 2016 due to increasing EWR expenditures.[313]

Ms. York explained that there is no regulatory lag with respect to collecting EWR program costs. She testified that because the company files periodic EWR plan cases, wherein surcharges are approved, it allows the company to recover costs in the same year in which they are incurred. In addition, the company files annual reconciliation cases to reconcile EWR costs, including a calculation of the FIM, with surcharge revenues. In addition, Consumers may reallocate up to 30% of its funding between programs without the need to file an amended plan, and there is currently no cap on EWR spending,

---

[309] Id. at 3083-3084.
[310] Id. at 3087-3088; Table 3.
[311] 7 Tr 2829-2830.
[312] Id. at 2831; Table 6.
[313] 7 Tr 2832; Table 7.

provided that the EWR portfolio overall is cost-effective. Ms. York stated that Consumers has consistently met or exceeded EWR targets, and although the Commission has the discretion to disallow unreasonable or imprudent EWR costs, she is unaware of any disallowance that the Commission may have imposed.[314] According to Ms. York:

> Based on the decade of experience thus far, and Consumers' continued ability to significantly exceed its legislatively-required spending levels with seemingly little risk of cost disallowance, I believe the EWR paradigm in itself more than adequately incentivizes Consumers to invest in EWR programs.[315]

Ms. York testified that an IRP case is not the proper proceeding to request or approve an FIM, and that the determination of the performance metrics and amount of the incentive are undertaken in EWR plan and reconciliation cases. Ms. York explained that it is not appropriate to approve a specific dollar amount for the EWR FIM when energy savings and actual program expenses are not known.[316]

On behalf of UCC, Mr. Cira-Reyes questioned whether low-income customers should pay for EWR programs that they cannot access and whether Consumers can achieve the levels of energy efficiency savings it projects without more low-income energy efficiency. With regard to accessibility, Mr. Cira-Reyes pointed to numerous programs that provide rebates for the purchase of energy efficient appliances, testifying that in order to participate in a rebate program, a customer must first have the up-front funds to purchase the product, a requirement that excludes many low-income customers. And, in cases where a customer is a tenant, the property owner has no incentive to invest in energy efficiency when the renter benefits from lower utility bills.[317]

---

[314] 7 Tr 2833-2834.
[315] Id. at 2835.
[316] Id. at 2835-2836.
[317] 7 Tr 2518.

Referencing Exhibit UCC-52, Mr. Reyes testified that although one third of the households in Consumers' service territory are low-income, these households only receive about one sixth of EWR funding. Despite this, Consumers' EWR potential study assumes that low-income households will reduce energy usage at a greater rate than other residential customers. Thus, in order for the company to reach its EWR levels in its IRP, Consumers must implement programs targeted at the needs of low-income communities.[318] Mr. Cira-Reyes added that it also may be more difficult for Consumers to attract low-income customers due a lack of trust in for-profit entities offering energy efficiency programs. Mr. Cira-Reyes cited budget billing options offered to low-income and communities of color that led customers to believe that this option would reduce bills. Instead, many customers received "surprise" bills at the end of the program because customers had used more electricity than forecast when calculating the monthly billing amount.[319] Mr. Cira-Reyes urged Consumers to rebuild trust by involving low-income and communities of color in IRP planning and actively engaging these customers in EWR and other programs.[320]

Ms. Waske Sutter discussed the objectives, progress, and achievements of sustainability efforts in Grand Rapids, and she testified regarding the importance of EWR in the City's goal to achieve zero net carbon. Echoing Mr. Cira-Reyes' concerns, Ms. Waske Sutter explained that there are significant issues with ensuring that low-income customers can participate in EWR programs, observing that higher levels of EWR savings may be achieved if Consumers focuses more efforts on making EWR available to low-

[318] Id. at 2519.
[319] Id. at 2519-2520; Exhibits UCC-2 and UCC-53.
[320] 7 Tr 2520.

income customers and small businesses. Citing a survey of 120 low-income residents on energy assistance, only 35 of those surveyed recognized Consumers' Energy Efficiency Assistance program, although over half of the participants were interested in participating in EWR programs. The survey also indicated that there were barriers to participation including lack of awareness of the programs, ineligibility, and significant paperwork.[321]

Referencing Exhibit CEO-4, Ms. Waske Sutter also discussed the significant energy burden for Grand Rapids customers at or near the federal poverty level (FPL), noting that energy efficiency could not only increase the ability to pay utility bills but also help prevent evictions for low-income renters.

On behalf of the CEOs, Dr. Lukanov discussed the energy cost (EC) burden, defined as the percentage of household income spent on energy needs, as well as the various factors that contribute to high EC burden. Dr. Lukanov observed that the average EC burden for households in the United States is 8.6% for low-income households and 3% for non-low-income households, adding that a household spending more than 6% on energy costs is considered energy burdened.[322]

Based on data from the U.S. Census bureau, Dr. Lukanov developed a map of EC burden across Consumers' service territory, noting that total EC burden in the service area is higher in rural areas, whereas electric EC burden tends to be higher in urban areas.[323] And, in urban areas where electric EC burdens are higher, Black residents have

[321] 7 Tr 2348-2349.
[322] 7 Tr 2434.
[323] Id. at 2438-2439; Figures 1 and 2.

higher EC burdens than white residents, and renters tend to have higher EC burdens than homeowners.[324]

Dr. Lukanov discussed the important role of energy efficiency in reducing EC burden but noted that there were several barriers, including upfront costs, which can limit access to energy efficiency programs for low-income customers and communities of color. According to Dr. Lukanov, "[t]his is critical because simple efficiency measures can decrease a low-income household's energy consumption 13 to 31 percent. These cost savings could be substantial for the most cost-burdened households, significantly improving energy affordability."[325]

Dr. Lukanov suggested that low-income EWR could be modeled separately in the IRP, noting that both environmental justice and climate goals are required to be considered in IRPs per ED 2020-10, stating, "[i]f requirements for energy cost burden disparity reductions are imposed as constraints within IRP modeling and optimization, then low-income energy efficiency and weatherization can serve as a viable resource to address these energy burden goals and simultaneously reduce societal costs, despite the higher resource cost."[326]

In response to Ms. Smith, Mr. McLean agreed that Consumers can endeavor to achieve higher energy savings than projected in the PCA, cautioning that overestimating EWR savings could have an adverse impact on long-term capacity planning. Nevertheless, according to Mr. McLean, the company will continue its goal to achieve 2%

[324] 7 Tr 2443-2444; Figure 5.
[325] 7 Tr 2447.
[326] Id. at 2448.

energy savings, and it will continue to evaluate and update EWR savings potential in future IRP cases.[327]

Mr. McLean disagreed with Mr. Proudfoot's recommendation that all EWR costs should be approved in EWR cases, testifying that the majority of EWR costs are O&M. According to Mr. McLean, "[l]ike capital investment in supply-side resources, pre-approval of the EWR spending gives the Company planning assurance for future investment and earnings. Pre-approval of the EWR O&M will not alter the fact that the actual EWR spending will be reviewed and approved during EWR plan filings and reconciliation proceedings. It will, however, send a clear signal that the Commission supports recovery of the spending and associated incentive at the Company's requested level."[328] Similarly, in response to Ms. York's recommendation to reject the company's request for an FIM in this proceeding, Mr. McLean pointed out that the actual amount of the financial incentive will be calculated and approved in an EWR reconciliation. Nevertheless, approval in the IRP will signal that the Commission approves the FIM level and will provide assurance of cost recovery.[329]

Mr. Blumenstock also disagreed with Mr. Proudfoot's assessment of the costs that may be approved in an IRP. According to him, "all requested capital and [O&M] costs for demand-side management programs—EWR, DR, and CVR—are integrally related and should not be severed. . . . The O&M is necessary to support the continued performance and expansion of these programs."[330] In response to Mr. Proudfoot's reliance on the language in MCL 460.6t(11), Mr. Blumenstock testified:

[327] 7 Tr 1892-1893.
[328] Id. at 1894.
[329] Id. at 1895.
[330] 3 Tr 199.

> Although Mr. Proudfoot cites MCL 460.6t(11) in his testimony for support, he does not appear to observe all applicable language in that provision regarding what costs can be approved in an IRP. Staff witness Proudfoot accurately mentions that MCL 460.6t(11) mentions cost approval of "investments" but he fails to note that MCL 460.6t(11) provides for the approval of "investments or resources used to meet energy and capacity needs..."
>
> * * *
>
> Mr. Proudfoot fails to reconcile his proposed limitation related to the IRP approval of just "investments" with the actual language in MCL 460.6t(11) which provides for the approval of "investments or resources." If the Legislature had intended to limit IRP approval to only investments, as Mr. Proudfoot claims, there would be no need to include the word "resources" as well as the word "investments" in MCL 460.6t(11). The inclusion of the word "resources" in MCL 460.6t(11) allows for the IRP approval of capital expenditures and O&M costs, among other things, for programs like EWR, DR, and CVR. This is particularly true with respect to programs like EWR which are recovered through O&M costs, as opposed to capital expenditures, and are used "to meet energy and capacity needs that are included in the approved integrated resource plan." If Mr. Proudfoot's interpretation of the law were true, utilities would be unreasonably forced to forgo the pre-approval of resources integrated into long- term resource plans simply because those resources are recovered through O&M costs.[331]

In response to Dr. Dismukes' claim that EWR is not cost-effective, Mr. McLean testified that Dr. Dismukes' calculation was erroneous because he compared one year of EWR costs to only one year of EWR savings. According to Mr. McLean, the weighted average life of an energy efficiency measure implemented as part of EWR programs is 11.31 years. Thus, "[w]hen correctly considering the measure life, the lifetime cost of conserved energy for the 2025 EWR investment is $0.03213 per kWh, not $0.50 per kWh [that Dr. Dismukes calculated]."[332] Ms. Smith likewise pointed out that Dr. Dismukes erred by including only first year energy savings rather than cumulative savings from each measure, noting that in 2020, Consumers "was able to generate lifetime savings equal to

[331] Id. at 200-201.
[332] Id. at 1896; Exhibit A-80, line 12.

6,317,782,518 MWh[,] . . . and the Company's projections for future savings values are similar if not higher."[333]

In response to questions and concerns about low-income EWR raised by Dr. Lukanov, Ms. Waske Sutter, and Mr. Cira-Reyes, Mr. McLean explained that Consumers has numerous EWR programs for low-income customers and is committed to expanding those offerings, noting that in its current EWR plan case, the company proposes to increase low-income spending by 22.9% and 24.3% in 2022 and 2023. Mr. McLean listed several new low-income initiatives, adding that the company intends to pair its EWR programs with bill assistance and other low-income efforts, and expand its income qualification level from 200% to 250% of FPL.[334] In addition, Mr. McLean testified that the company is actively participating with the Energy Affordability and Accessibility and EWR Low Income workgroups, and it has committed 1% of its EWR budget to address residential health and safety issues through pilot programs.[335]

Next, Mr. McLean addressed Mr. Cira-Reyes' suggestion that low-income customers should not have to pay for EWR programs from which they do not benefit, explaining that the EWR programs provided to income-qualified customers are offered at no cost to the participant and Consumers' low-income EWR programs continue to grow. In addition, Mr. McLean testified that Consumers recognizes the benefits of working with local communities and non-profits in implementing low-income programs to increase awareness and to identify and address barriers to participation.[336]

---

[333] 8 Tr 3714.
[334] 7 Tr 1897.
[335] Id. at 1897-1898.
[336] Id. at 1898.

In response to Dr. Lukanov's recommendation that the company model low-income EWR as a separate resource in the IRP, Mr. McLean testified that this was unnecessary since costs and savings for low-income EWR are included as part of the overall EWR costs and savings in the modeling. Mr. McLean pointed out that low-income programs are not required to be cost-effective, which allows these programs to be affordable to qualified customers.[337]

Mr. McLean agreed with Mr. Neme that the company's analysis does not fully reflect the EWR savings associated with avoided T&D costs, noting that these savings are typically included in EWR plans. The exclusion of T&D savings however did not reflect the amount of energy efficiency included in the PCA, because the IRP includes all achievable EWR potential. Likewise, Mr. McLean agreed that the inclusion of post-2040 energy savings would increase the value of EWR, testifying that the company could include these savings in EWR modeling in future IRPs. Nevertheless, including the value of EWR benefits beyond the planning period would not increase the amount of EWR selected here. As for using marginal, rather than average, line losses in the modeling, Mr. McLean explained that Consumers does not currently perform marginal line loss studies and it is unclear what the impact of using marginal line losses would be on the economics of EWR. For future IRPs, Mr. McLean testified that, "[t]he Company is willing to explore options for capturing additional EWR benefits in future IRP filings, but . . . the Company is not certain whether the recommended modifications will be feasible or

[337] Id. at 1899.

worthwhile, and thus does not believe that the Commission should require the Company to make these specific changes in future IRPs."[338]

The following issues concerning EWR were raised and are addressed below: (1) the incorporation of EC burden and low-income EWR into the modeling as well as opportunities for participation by low-income and communities of color in EWR programs; (2) whether the levels of EWR over the plan period are reasonable and prudent; (3) whether the NPV of EWR was properly calculated in the company's modeling; and (4) whether EWR capital, O&M, or FIM costs should be approved as part of this proceeding or whether these costs should be reviewed and approved as part of the company's EWR plan and reconciliation cases.

First, although this PFD finds that the concerns regarding EC burden and low-income EWR programs raised by the UCC and the CEO's have considerable merit, these issues are outside the scope of what can be addressed in an IRP. Specific matters involving funding, programming, accessibility, and participation by different customer groups are properly and comprehensively addressed in an EWR plan case,[339] or through participation in one or more of the Commission workgroups addressing energy affordability, EWR, or low-income issues. Similarly, this PFD finds that the Attorney General's recommendation to scrutinize non-program and FIM costs to ensure that EWR remains cost effective should be addressed as part of EWR plan or reconciliation proceedings.

[338] Id. at 1901.
[339] See, e.g., the recently approved low-income EWR programming for DTE Electric and DTE Gas in Case Nos. U-20876 and U-20881.

In a related issue, this PFD finds that separating low-income EWR as a resource option in the IRP, as suggested by Dr. Lukanov, is not well supported. As Consumers points out, low-income EWR is already incorporated into the EWR cost and savings inputs in its modeling, and it is not clear what purpose breaking out low-income EWR as a separate resource would serve. In addition, because low-income EWR programs are not required to be cost-effective, it appears unlikely that this resource would be selected in the modeling were it to be separately included. That said, Consumers indicates that it would be willing to undertake an EC burden analysis as part of a future IRP, suggesting:

> If the Commission desires to consider Mr. Lukanov's recommendation concerning energy cost burden analyses, it would be most appropriate to consider this issue in the Advanced Planning Phase III effort being led by the MPSC to revise the Michigan IRP modeling parameters and filing requirements. 3 TR 210-211. In that forum, the MPSC could provide guidance as to how Michigan utilities should conduct such analyses. The Commission should not approve different energy cost burden requirements for each utility.[340]

The PFD agrees with Consumers' recommendation.

Turning to the second and third issues, Consumers contends that the EWR levels included in this IRP are reasonable and prudent, noting that the company will continue to pursue 2% EWR savings. Staff describes the company's EWR modeling as "on target," and MNS urges the Commission to direct Consumers to increase its EWR level to 2% throughout the plan period. MNS argues that Consumers' failure to consider post-plan benefits of EWR, coupled with the company's exclusion of T&D benefits and the use of average rather than marginal line loss rates, resulted in an undervaluation of EWR.

---

[340] Consumers brief, pp. 434-435.

Consumers responds that it would be willing to consider MNS's suggestions for improved modeling of EWR in a future IRP,[341] however, because the PCA presented here includes all achievable EWR, including additional EWR benefits as MNS suggests, would not have increased the amount of EWR in this IRP. Finally, the Attorney General maintains that, although she does not recommend discontinuation of the EWR program, she restates Dr. Dismukes' calculation of the high cost of EWR relative to other resources.[342]

Concerning the Attorney General's claim regarding the cost of EWR compared to other supply and demand-side resources, this PFD agrees that Dr. Dismukes' calculation compares the total cost of an energy efficiency measure, generally incurred in year one, with only the first year of energy savings, although, as Staff and Consumers point out, the average life of an energy efficiency measure is over 11 years. Although the Attorney General acknowledges rebuttal on this issue in her brief, she contends that this is "beside the point raised by the Attorney General."[343] This PFD finds that the Attorney General's claim that EWR is less cost-effective than supply-side and other demand-side resources considered in this IRP should be rejected for the reasons stated in Ms. Smith's and Mr. McLean's rebuttal testimony cited above.

As for MNS's recommendation to amend the IRP to include 2% EWR savings, this PFD finds that, in light of the company's commitment to achieve EWR savings of 2% coupled with the need to ensure sufficient capacity over the plan period, Consumers'

---

[341] Consumers states that "the Commission should not require the Company to incorporate Mr. Neme's recommendations into future IRPs because it is not certain whether the recommended modifications will be feasible or worthwhile. The Company will continue to seek to incorporate all applicable EWR benefits in future IRP proceedings to appropriately capture the economics of the EWR program. 7 TR 1901."
[342] Attorney General brief, pp. 71-72.
[343] Id. at 74.

assumptions about EWR levels used in its modeling are reasonable and supported. Consumers points out that although MNS's claims about the economics of EWR are correct, it would not make a difference in the amount of EWR that would have been included in this IRP. The PFD does agree with MNS that in future IRPs, the company should be directed to more accurately reflect the benefits of EWR by including avoided T&D costs, using estimated marginal rather than average line losses, and accounting for benefits of EWR that accrue after the plan period. In addition, to ensure that the costs of EWR and other demand-side resources are reasonably accurate in the modeling, Consumers should include an FIM amount that reflects incentive costs associated with the most recently-approved FIM.

Finally, Staff agrees that in order to correctly model EWR, DR, and CVR, the company should include capital, O&M, and FIM costs in evaluating the resource. However, Staff maintains that these costs for EWR should not be explicitly approved as part of this proceeding. Instead, Staff points to the EWR plan and reconciliation processes outlined in Subpart C of Act 295, MCL 460.1071 *et seq*. ABATE likewise argues that the appropriate place to address EWR costs is in EWR proceedings, and ABATE highlights the fact that the FIM amount is unknown at this time and is dependent on actual energy savings demonstrated in the EWR reconciliation.[344]

Although the Commission has preapproved EWR costs in at least one other IRP proceeding,[345] this PFD agrees with Staff and ABATE that although EWR cost projections should be included in the modeling, all EWR costs should be evaluated and approved as

---

[344] ABATE brief, pp. 41-42.
[345] See, February 20, 2020 order in Case No. U-20471 et al., p. 88.

part of the process established under Act 295. As ABATE points out, there is no real concern with regulatory lag, because the company collects EWR costs contemporaneously through a surcharge, which is then trued up in the reconciliation. In addition, it appears that Consumers' FIM for EWR proposed here is based on 20% of non-capital spending. It is unclear whether the company would then expect an incentive at that level to be paid based on a preapproval in the IRP.

Consumers' claims that preapproval of EWR costs in this proceeding would provide "assurance of cost recovery to encourage investment in EWR resources" and would "send[] a clear signal that the Commission supports recovery of the planned spending and associated incentive amounts[,]"[346] are vague and appear to be a solution to a problem that does not exist. Since the enactment of Act 295, the Commission has consistently approved EWR costs without imposing disallowances. Moreover, if the Commission approves the level of EWR proposed in this proceeding, it is unclear how the Commission could then deny the recovery of the expenses necessary to achieve the approved level of EWR.

If, on the other hand, the Commission finds that preapproval of EWR costs in this IRP is reasonable, the PFD agrees with Staff's position that only capital costs should be approved for this and other demand-side programs. As Staff recommends, O&M and FIM costs are more appropriately addressed in other proceedings.

The PFD agrees with Staff that the language in Section 6t(11) referencing "specifically identified investments" like the construction or purchase of an electric generating facility or a PPA must be read in context. As Staff argues:

[346] Consumers brief, p. 304, citing 7 Tr 1894.

> Consumers argues in rebuttal testimony that the catchall in Act 341 was intended to expand the list of investments that qualify for preapproval. The Act allows the Commission to preapprove, in addition to the capital investments listed, "other *investments or resources* used to meet energy and capacity needs that are included in the approved integrated resource plan." MCL 460.6t(11) (emphasis added). The Company claims that Staff's interpretation cannot be squared with the "actual language in MCL 460.6t(11) which provides for the approval of 'investments or resources.' " (3 TR 200.) The problem for the Company is that principles of statutory construction dictate that the "other investments or resources" mentioned must be in the same class as the capital investments listed beforehand.
>
> Under the doctrine of *ejusdem generis*, "when a general word or phrase follows a list of specifics, the general word or phrase will be interpreted to include only items of the same class as those listed." *Home-Owners Ins Co v Andriacchi*, 320 Mich App 52, 63 (2017). O&M expenses are not in the same class as the listed capital investments. Id. As Staff witness Paul Proudfoot succinctly said, "While section 6t(11) specifically mentions the approval of costs for investments, it does not mention the approval of costs that would be classified as expenses." (8 TR 3415.) Thus, the catchall in Section 6t(11) does not cover O&M expenses.[347]

In response, Consumers asserts that Staff's position "is legally flawed and not reasonable[,]"[348] contending that Section 6t(11) provides for four separate categories of costs including (1) the construction or significant investment in an electric generating facility; (2) the purchase of an electric generating facility; (3) PPA(s); and (4) "other investments or resources to meet energy and capacity needs."[349] According to the company, while the first two categories are arguably capital costs, PPAs and "other investments or resources" include costs in addition to capital costs. Consumers asserts that reading the statutory language to include only capital expense renders the phrase "other investments or resources" nugatory.[350] Consumers adds that even if the

[347]Staff brief, pp. 8-9.
[348] Consumers reply brief, p. 168.
[349] Id.
[350] Id. at 168-169, quoting *State Farm Fire & Cas Co v Old Republic Ins Co*, 466 Mich 142, 146; 644 NW2d 715 (2002).

Commission were to find that Section 6t(11) does not include O&M costs, the Commission can nevertheless approve the company's proposed O&M costs under its broad ratemaking authority.[351]

Leaving aside the parties' arguments about the appropriate canon of construction to apply, this PFD finds that Consumers' position should be rejected for two reasons. First, the plain language of Section 6t(11) requires the Commission to "specify" that is, "to identify clearly and definitively" [352] "the costs approved for . . . other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan." While the Commission can certainly specify some costs, for example, those associated with the purchase of a generating plant or with a PPA, the costs of which are established before filing an IRP, other costs, namely those associated with demand-side programs, which are dynamic and tend to vary from year to year, cannot be "identif[ied] clearly and definitively." This is especially true in the case of financial incentives, where the mechanism may change and where the amount is calculated based on actual performance.[353]

Second, as Staff points out, there is a specific statute for addressing EWR programs and costs under Act 295 that has worked well since its inception in 2008. While Section 6t was added in 2016, the provisions of Act 295 were amended at the same time. Thus, adopting Consumers' argument that all EWR costs for the next three years must be approved as part of the IRP, could render the cost review, approval, and reconciliation

[351] Consumers reply brief, p. 171.
[352] Oxford American Dictionary (2001).
[353] The ALJ further observes that Section 6(t)12 allows for additional activities for establishing the cost for the construction of an electric generating facility, including competitive bidding for engineering, procurement, and construction, and an additional review if final costs exceed the costs approved in the IRP. No such protections are available for demand-side resources.

provisions of Act 295 nugatory. Finally, as ABATE argues, Consumers is able to collect its current costs through the EWR surcharge with no need to file a rate case or experience any regulatory lag in the collection of EWR expenses.

In summary, with respect to EWR costs, this PFD finds that approval of actual costs (capital and O&M) should be addressed comprehensively as part of the company's EWR plan case. If the Commission finds that some EWR costs should be approved here, the approval should be limited to the incremental EWR capital costs proposed by the company.

2. Demand Response

Ms. McGraw provided an overview of Consumers' residential and business DR programs and DR savings incorporated into the IRP. She also discussed costs for DR, for which the company requests preapproval in this IRP. As shown in Exhibit A-82, the amount of DR in the PCA increases from 607 MW in 2022 to 698 MW in 2030 and then remains at that level through 2040. Ms. McGraw explained that the company based its DR savings on several factors, including historical performance, DR savings levels included in the company's previous IRP, and the Demand Response Potential Study by Cadmus and Demand Side Analytics (Cadmus Study) contained in Exhibit A-85. In addition, Consumers included scenarios from the Statewide Demand Response Potential Study (Statewide DR Study) conducted in 2018.[354]

Ms. McGraw testified that for 2023-2025, Consumers is seeking preapproval of: (1) $23.7 million in DR capital costs; (2) O&M in the amount of $3.1 million; and (3) a DR

[354] 6 Tr 1441-1447.

FIM of $26.3 million based on a 20% performance incentive consistent with the company's request in Case No. U-20766.[355]

Ms. McGraw explained that the company's previous IRP included DR amounts up to 1,250 MW by 2031, whereas this PCA reduces this amount to approximately 700 MW by 2031. According to Ms. McGraw, this modification was the result of impacts of EWR measures and the company's change to a summer peak rate for all residential customers, which has resulted in some load-shifting to off-peak hours.[356]

Ms. McGraw discussed execution risks associated with the business and residential customer DR programs that could affect the amount of DR ultimately obtained, but she also indicated that the company intends to achieve the DR targets with flexibility to balance DR targets among programs.[357]

Ms. McGraw also discussed Consumers' rationale for a DR incentive, highlighting comments filed by the Advanced Energy Management Alliance in Case No. U-18369, stating that, "demand-response will not truly be on equal footing with generation, even if there is a comparable consideration in the regulatory process. From a utility's perspective, they are worse off if they invest in a program for which they cannot earn a return than if they invest in a capital project where returns are guaranteed. Given a fiduciary duty to shareholders [investing in demand-response resources] may be an imprudent choice for the utility even if it is the best choice for their customers."[358] Ms. McGraw added that the company has traditionally invested in supply-side resources to serve its customers and,

---

[355] Id. at 1449.
[356] Id. at 1450.
[357] Id. at 1451-1452.
[358] Id. at 1454.

absent an appropriate FIM, Consumers is unlikely to invest in DR beyond what is included in the PCA.

Mr. Doherty testified that Staff has concerns about the cost-effectiveness of Consumers' DR program, pointing to Exhibit S-6.1, which shows that DR programs cost approximately $100,000/MW-year, compared to CONE at $98,801/MW-year. Mr. Doherty cautioned that there are other ways to evaluate the cost-effectiveness of DR and that the comparison in Exhibit S-1 may not mean that the company's DR efforts are not cost-effective. But the relatively high cost of DR indicates that these programs should be evaluated for cost-effectiveness, and the way that DR is modeled (and selected) in the IRP requires more scrutiny.[359] Mr. Doherty recommended that to improve the accuracy of modeling DR in future IRPs, Consumers should offer DR resources into the model at the program level, rather than portfolio level.[360]

Noting the significant reduction in DR resources proposed in this IRP, compared to the company's previous plan, Mr. Doherty testified that Staff does not take issue with the reduction, given the high cost of DR (including a 20% FIM in the modeling), the results of the updated potential study, and the summer peak rate that have reduced peak load and limited some DR resource options. Mr. Doherty observed that the DR proposals in this case also reflect a shift from the modular, more flexible approach to resource additions used in the 2018 IRP to this IRP, which relies on the addition of large generating resources. According to Mr. Doherty, "Staff is not convinced that conditions have

[359] 8 Tr 3492.
[360] Id. at 3493.

changed to the extent that would merit completely abandoning that flexibility in this IRP."[361]

Mr. Doherty compared the Cadmus Study to the most recently-completed statewide potential study (Guidehouse Study), noting that the Guidehouse Study was not available when Consumers was preparing its IRP. Mr. Doherty testified that the Guidehouse Study generally found a higher potential for cost-effective DR, specifically an additional 640 MW above the company's current DR level of 500 MW, bringing Consumers' achievable DR potential to 1,100 MW by 2030. Mr. Doherty testified that the differences in the Cadmus Study and Guidehouse Study were the result of different assumptions, particularly a higher cost-effectiveness limit and additional DR programs in the Guidehouse Study.[362]

Mr. Doherty testified that Staff supports Consumers' request for DR capital costs of $23,751,000 for January 1, 2023 through June 30, 2025, which should be approved as reasonable and prudent. He noted that the request includes $23.3 million in existing DR capital costs and incremental capital of $450,000. Mr. Doherty stated that Staff does not support the company's request for preapproval of O&M costs, recommending that instead these costs be reviewed and approved in Consumers' rate cases, as the Commission determined in Case No. U-18369.[363] Similarly, after outlining the current 15% FIM for DR, approved on September 24, 2021 in Case No. U-20766, Mr. Doherty testified that the Staff does not support preapproval of costs that have not been determined. Therefore,

[361] Id. at 3495.
[362] Id. at 3496.
[363] Id. at 3498.

Staff recommends that the Commission deny Consumers' request for preapproval of an FIM for DR.[364]

Mr. Doherty testified that Staff also has concerns about DR performance during MISO emergencies, pointing to the poor response of DR resources when called up during the 2019 polar vortex. Noting that the Commission has issued reports and orders on the need for better DR response, Mr. Doherty maintained that Staff believes that improvements should still be made to ensure that DR is available when events are called.

Ms. York testified that the Commission should reject Consumers' request for preapproval of a DR FIM, noting that although the company requests an FIM equal to 20% of non-capitalized DR costs, the Commission recently determined that it was premature to increase the incentive above 15% in its order in Case No. U-20766.[365] Ms. York testified that, like EWR cost recovery, Consumers has no risk of regulatory lag in recovering its DR costs, pointing to the three-phase approach for DR cost approval, recovery, and reconciliation. As such, Ms. York opined that as long as FIM issues are considered in DR reconciliations, there is no need to address them in the IRP.[366]

Consistent with his concerns about undervaluing EWR, Mr. Neme again pointed out that Consumers failed to include avoided T&D costs in its analysis, and the company used average rather than marginal line loss rates. Mr. Neme testified that when asked about T&D benefits associated with DR, Consumers responded that it had limited experience in evaluating the effects of DR on T&D costs and therefore did not quantify avoided T&D costs in its modeling. Mr. Neme stated that simply because the company's

---

[364] Id. at 3498-3499.
[365] 7 Tr 2836, citing September 24, 2021 order in Case No. U-20766, p. 7.
[366] 7 Tr 2838.

experience was limited, this was no reason to assume $0 benefits from avoided T&D, adding that failing to include the benefits of avoided T&D costs could bias resource selection.[367]

Mr. Neme testified that DR can reduce T&D costs in two ways. First, during coincident peak times, DR provides both system and local distribution peak savings, thus, "[a]ross a system with over 2000 circuits, that will mean some deferral of distribution system investments."[368] Second, Mr. Neme explained that for parts of the system that peak at different times, DR could be part of a non-wires solution that could defer capital investments that are driven by load growth.[369] According to Mr. Neme, even without actual numbers, Consumers could assume that the avoided T&D benefits of DR are comparable to the avoided T&D benefits of EWR. Mr. Neme testified that had the company included avoided T&D costs in its modeling of DR, Consumers would have included significantly more DR in its PCA.[370]

Turning to line loss rates, Mr. Neme reiterated that the use of average, rather than marginal, line losses results in an underestimate of savings for all demand-side programs. According to Mr. Neme, "[i]n a nutshell, it would be reasonable to assume that the peak demand benefits of the demand response resources Consumers has analyzed in its IRP would be about 15.7% greater in magnitude than the Company has assumed. It also means that more demand response could be cost-effective."[371] Mr. Neme concluded that if Consumers DR assumptions were adjusted to include marginal line losses and avoided

[367] 8 Tr 3089-3090.
[368] Id. at 3090.
[369] Id.
[370] 8 Tr 3092-3093.
[371] Id. at 3093.

T&D costs, DR acquisition would increase from the 91 MW of incremental capacity in the PCA to 261 MW of additional cost-effective DR capacity.[372]

On behalf of CUB, Mr. Gard discussed the importance of residential DR, which provides customers with more information and control over their energy use and costs. Mr. Gard discussed the Cadmus Study, developed for the company in 2020, noting that Consumers relied extensively on that study in determining DR levels for its PCA. Mr. Gard testified that for residential customers, Consumers assumes that DR programs remain at 169 MW from 2030-2040; however, he opined that the company's projection for residential DR is too conservative. In part, this was due to the company's use of a line loss factor of 3.7% for residential customers, rather 7.73%, which is more accurate for customers connected at the distribution level.[373] According to Mr. Gard, using a higher, more appropriate, line loss factor results in more cost-effective residential DR. In addition, Mr. Gard explained that because DR is generally called during high demand periods, when line losses are even greater, residential DR has even more value when considering marginal line losses. Thus, Mr. Gard recommended that the Commission direct Consumers to collect the necessary data to estimate marginal line losses along with average line loss rates.[374]

Mr. Gard observed that the Cadmus Study evaluated only avoided costs of generation capacity and energy, but it did not consider avoided T&D and ancillary services costs. On the other hand, the Guidehouse Study assumed 80% of avoided costs were associated with generation and 20% were T&D avoided capacity. According to Mr.

[372] Id. at 3094; Confidential Table 6.
[373] 7 Tr 2461-2462.
[374] Id. at 2462-2463.

Gard, although Consumers claimed that T&D avoided costs would need to be tied to a specific capital upgrade, the company did not provide any rationale for why these costs could not have been included in the Cadmus Study. Had the company included avoided T&D costs, the total avoided capacity costs for DR would have increased from $106/kW-year in 2021 to $152/kW-year in 2040, according to the Guidehouse Study.[375] Mr. Gard further noted that the Cadmus Study included a 20% FIM, despite the fact that the Commission recently rejected such a high incentive in Case No. U-20766, adding that the Commission should also reject the proposed FIM here.

Mr. Gard criticized the Cadmus Study for including only existing DR offerings in its analysis, even though the report acknowledged that in the later years of the study horizon, new DR technologies or programs a likely to emerge. According to Mr. Gard, "[t]his limitation of the Cadmus study is particularly salient given the PCA's flat residential DR potential of 169 MW from 2030 to 2040."[376]

Mr. Gard also took issue with the assumptions about residential customer behavior in the Cadmus Study, testifying that the study failed to consider the diversity of needs and preferences of various customer groups, and contending that the assumptions were "relatively simplistic and unsophisticated."[377] In addition, Mr. Gard criticized the Cadmus Study for assuming that Consumers will continue to be a summer-peaking utility in the future and failing to consider the value of DR in the winter. Mr. Gard also raised concerns about the failure to model DR in extreme weather conditions or to consider increased load due to building electrification.[378]

[375] Id. at 2463-2464; Exhibit CUB-2, p. 68.
[376] 7 Tr 2465.
[377] Id. at 2466.
[378] Id. at 2466-2467.

Mr. Gard acknowledged that given the different assumptions and modeling used in the Cadmus and Guidehouse potential studies, it is difficult to make direct comparisons of the results. Nevertheless, the Guidehouse Study shows significantly greater potential for residential DR, particularly after 2030.[379]

In response to witnesses who opposed the FIM, Ms. McGraw explained that the assurance of cost recovery, including the FIM, is important to planning for DR resources, noting that Consumers recognizes that the amount of the DR incentive may change in the DR reconciliation. Ms. McGraw added that using a 20% incentive in the DR analysis did not materially change the result, and while a lower incentive may increase cost-effectiveness, it may reduce the company's motivation to invest in DR.[380]

In response to Staff's recommendation to exclude DR O&M costs from preapproval in this case, Ms. McGraw reiterated that "[l]ike capital investment in supply-side resources, pre-approval of the DR O&M spending gives the Company planning assurance with regard to future investment and earnings. Pre-approval of the DR programs O&M will not alter the fact that the actual DR spending will be reviewed and approved during rate cases and DR reconciliation proceedings."[381]

Ms. McGraw testified that Consumers agrees with Mr. Doherty that evaluating DR at the program, rather than portfolio, level in the company's modeling could be useful; however, she cautioned that there might be additional administrative costs shifted from programs that are not selected in the modeling to those that are. Thus, DR will still need to be evaluated at a portfolio level. Ms. McGraw also agreed with Mr. Doherty's concerns

---

[379] 7 Tr 2467-2468; Figure 1, 7 Tr 2468.
[380] 6 Tr 1459.
[381] 6 Tr 1460.

about DR performance during emergencies. She testified that Consumers will continue to work with business customers, updating the company's procedures and communications, especially concerning MISO maximum generation events.[382]

In response to Mr. Neme, Ms. McGraw explained that including T&D costs would have a minimal effect on the analysis, testifying that T&D cost avoidance is location-specific and that the Cadmus Study properly assumed that the MISO ancillary service market for small, disaggregated resources is limited. Ms. McGraw added that Consumers is exploring the use of focused DR as part of a non-wires solution. Ms. McGraw agreed with Mr. Neme that it would be technically correct to use marginal rather than average line losses for evaluating DR avoided costs, but again noted it would have little or no impact on the DR study. Nevertheless, Ms. McGraw indicated that Consumers agrees to explore the benefits of including avoided T&D costs and marginal line losses in a future IRP.[383]

In response to Mr. Gard's critique of the Cadmus Study, Ms. McGraw testified that his recommended improvements would have little impact on Consumers' DR modeling and that the company believes that the level of DR included in the PCA is realistic and accurate. Specifically, with respect to the appropriate line loss percentage, Ms. McGraw explained that the 3.7% factor the company used is more in line with the loss factor used to convert installed capacity (ICAP) to unforced capacity (UCAP), noting that "the higher line loss factor would have no impact on largest offering in our DR portfolio. The DR potential for Business Load Curtailment programs uses a 'top-down' approach using

[382] 6 Tr 1462-1463.
[383] Id. at 1463-1464.

forecasts of system load. System loads are inclusive of line losses, so the line assumption in the study has no impact."[384]

Ms. McGraw disagreed with Mr. Gard's claim that the Cadmus study was limited because it did not include potential for new DR technologies that could be implemented from 2030-2040. According to her, because the PCA includes replacement of existing resources, it is essential that those replacement resources be proven. In addition, Ms. McGraw disputed Mr. Gard's contentions that the Cadmus Study used simplistic assumptions about customer behavior, that it did not include the potential for winter DR or address extreme weather, and that it relied on a load forecast that was too low. Ms. McGraw testified that assumptions about customer behavior were based on the company's previous experience with DR enrollment as well as studies from other states, noting that residential DR enrollment tends to decline over time.[385] And, while Consumers agrees that there may be some value in winter DR, Ms. McGraw explained that both Consumers and MISO are summer-peaking. Thus, the IRP framework addresses avoided generation in the summer months. Ms. McGraw also outlined how Consumers worked with Cadmus on developing an analysis of heating electrification, concluding that additional heating electrification would not have an impact on the level of DR in this IRP. Finally, Ms. McGraw noted that while it is true that DR has more value in extreme weather, the DR modeling had to align with the peak load forecast, and more extreme weather would not equate to more DR.

[384] Id. at 1465.
[385] 6 Tr 1466.

The parties' briefs and reply briefs largely rely on the testimony of their respective witnesses. Consumers reiterates that its DR assumptions in the PCA are reasonable and accurate, urging the Commission to reject the recommendations of CUB and MNS concerning modeling assumptions and DR levels, noting that it would explore including avoided T&D costs and marginal line losses in a future IRP. Consumers agreed in part with Staff's recommendations to evaluate DR on a program rather than portfolio level and to increase outreach and communications with business customers to address DR failures in the future. Consumers further argues that the Commission should approve both O&M costs and the DR FIM in this proceeding, reiterating that "assurance of cost recovery is beneficial when planning to help program investments and encourage utility investment in DR[,]" noting that most DR costs are O&M and not capital.[386]

Citing Mr. Gard's testimony, CUB reiterates that Consumers' assumptions about residential DR are too conservative due to the use of average line losses and the failure to include avoided T&D costs. CUB contends that Consumers misses the point about including a higher line loss factor for residential DR, noting that although business DR is currently the majority of the company's DR portfolio, the Guidehouse Study found that residential customers have more than 60% of the DR potential for the Lower Peninsula. That potential cannot be realized absent more reasonable assumptions for residential DR, including the use of appropriate line loss rates for customers connected at the distribution level. CUB therefore urges the Commission to direct the company to reevaluate residential DR levels by including higher marginal line losses and avoided T&D

[386] Consumers brief, p. 294.

costs, consistent with the Guidehouse Study. CUB also recommends that the Commission reject the FIM proposal in this case.

While Staff recommends that the Commission approve Consumers' DR capital costs, it opposes the company's requests for O&M expenses and the FIM. Staff particularly takes issue with preapproval of incentives for any demand-side program, arguing that because DR O&M is approved in rate cases, and because the incentive is tied to O&M spending, then the appropriate place to address the FIM is in the reconciliation. Staff also points out that the company is requesting a 20% FIM in this case, despite the fact that the Commission recently rejected the same proposal in Case No. U-20766.

MNS repeats that Consumers undervalued DR in this IRP by assuming there are no distribution capacity benefits via avoided T&D costs and using inappropriate line loss rates. Accordingly, MNS recommends that the Commission direct the company to include avoided T&D and use marginal line loss rates in modeling DR in the company's next IRP.[387]

The PFD finds that, for purposes of this IRP, Consumers near-term assumptions about DR levels are reasonable and supported. The PFD agrees, however, that in modeling DR levels in future IRPs, the Commission should direct the company to use up-to-date potential studies; it should model DR on both the program and portfolio levels, and the company should incorporate estimated avoided T&D costs and estimated marginal line loss rates in developing its residential DR levels. CUB's concerns about the company's failure to fully consider the potential for residential DR are well-taken;

[387] MNS brief, pp. 120-122.

however, like EWR program issues, these concerns should be addressed in a DR reconciliation proceeding or in a rate case where they can be comprehensively evaluated. Likewise, the consideration of winter DR and DR under extreme weather events should be undertaken in proceedings specifically focused on DR programs.

As for cost approval, the Commission established a method for addressing DR costs in the September 15, 2017 order in Case No. U-18369. In that order, the Commission found that Staff's three-phase approach should be adopted for DR program evaluation, cost approval, and DR cost recovery. Under that approach, reasonable and prudent DR capital costs are approved in IRPs, "but operations and maintenance (O&M) costs will undergo review and approval in the utility's general rate case."[388] Actual capital and O&M costs are then reviewed and reconciled in a DR reconciliation case, along with the mechanics of the DR incentive mechanism and the actual incentive amount earned the previous year. Although Consumers again references the importance of assuring cost recovery, including an incentive, the company does not provide any evidence that the current procedure does not provide the requisite assurance. Therefore, consistent with the method approved in Case No. U-18369, the company's capital costs for the first three years of the program should be approved.

3. Conservation Voltage Reduction

Mr. Henry described CVR as:

> . . . a proven set of technologies that reduces the delivery voltage along electric circuits, then in turn reduces the amount of electric load that must

[388] Order, p. 8. The Commission recognized the need to, "ensure that the utility is able to recover the fixed investment required to implement successful DR programs, while allowing the Commission more regular oversight into the ongoing operation of those successful programs. Because the reconciliations provide the necessary review of many new programs that may deviate significantly from the initial plans proposed in an IRP or rate case, the Commission rejects DTE Electric's and Consumers' recommendations to dispense with these proceedings." Id. at 9.

be served on the electric circuit, and thus, on the electric system. The technology works together and optimizes control settings on both substation and downstream voltage regulating equipment. The technology allows for continuous monitoring and automatic adjustment of these settings to achieve optimal voltage and load reduction while staying within the regulatory requirements.[389]

Mr. Henry explained that the goal of CVR is to reduce energy demand "by optimizing service-point voltage without requiring active participation or behind the meter investment by customers[,]"[390] providing both EWR energy savings as well as DR capacity savings.[391]

Mr. Henry discussed Consumers' CVR pilot and evaluation, testifying that since first implemented in 2019, 50 low-voltage distribution (LVD) circuits were enabled. Since the conclusion of the CVR pilot, the company deployed CVR on an additional 25 circuits. And, while CVR enables demand reduction, Mr. Henry explained that for some circuits, particularly those that serve primarily commercial and industrial loads, CVR is not cost effective and will not be implemented.[392] Due to an interruption in CVR implementation and changes in residential demand due to COVID-19, Consumers intends to extend the pilot until September 30, 2021.[393]

Mr. Henry sponsored Exhibit A-86, which presents CVR circuit deployment for 2021-2040, along with projected MWh and MW reductions. Consumers forecasts that CVR will be implemented on 85 circuits per year through 2029, and 60 circuits in 2030, for a total of 900 circuits. Compared to the CVR levels in the settlement in the company's

[389] 7 Tr 1699.
[390] Id.
[391] Id. at 1703.
[392] Id. at 1700-1701; Exhibit A-90.
[393] Id. at 1702.

previous IRP, Consumers intends to increase CVR deployment by 400 circuits.[394] Consumers projects that this will result in capacity and energy reductions of 113 MW and 272 GWh by 2030.[395] Exhibit A-87 shows projected annual capital investments for CVR through 2030, and Exhibit A-88 shows projected annual O&M costs for CVR through 2040.[396] Exhibit A-89 shows the company's requested CVR capital and O&M costs for 2023 through mid-2025.

Mr. Becker provided an overview of Consumers' CVR program and its request for cost approvals of $9,736,315 for capital investment and O&M costs of $1,203,213 for a total 56.81 MW and 136,351 MWh capacity and energy reductions by June 30, 2025.[397] Mr. Becker testified that for this IRP, Consumers updated several of its assumptions based on its pilot, observing that, "the Company now needs nearly double the amount of CVR enabled circuits to reach the same MW and MWh reduction levels presented in the previous case, and the program's total capital costs have increased by over $13 million for the period of 2021-2040."[398] Given the cost increase, coupled with significant reductions in projected energy and capacity savings, Mr. Becker questioned the point at which the investment in CVR becomes uneconomic for customers. Mr. Becker also found Consumers' presentation on CVR lacking for its failure to include the impacts of DERs on CVR circuits, the dearth of information on constant energy devices for end use loads,[399] and the aforementioned failure to provide an economic break-even analysis.[400]

[394] Id. at 1711-1712; Figure 2.
[395] Id. at 1707.
[396] Id. at 1708-1709.
[397] 8 Tr 3424.
[398] 8 Tr 3425-3426; Table 1.
[399] According to Mr. Becker, constant energy devices are "those that are set to meet certain objectives such as water temperature and air temperature." 8 Tr 3428.
[400] 8 Tr 3427.

Mr. Becker testified that assessment of the impact of DERs on CVR circuits is critical because, to achieve the same reductions, additional capital may need to be invested in circuits with heavier DER penetration. Mr. Becker noted that Staff raised this issue in the company's previous IRP, and the Commission adopted Staff's recommendations for DER data analysis to enable consistency and transparency in utility planning.[401] Although Mr. Henry mentioned that constant energy devices, like water heaters and air conditioning, may limit CVR savings, Mr. Becker testified:

> AC units and water heaters are common appliances in many residential applications. Although the Company states constant energy devices are considered through the CVR factor calculation, this calculation is applied at the circuit level as an average and does not apply or consider usage at the customer level. The Company has not performed benchmarking specific to constant energy devices and consideration in CVR circuits. If not appropriately accounted for, the actual MWh and MW reductions realized would be a value less than projected.[402]

Regarding the economics of CVR, Mr. Becker explained that the costs of CVR have increased due to the company's plan to deploy CVR on 400 additional circuits. At the same time, savings are significantly less than projected, and capital costs for CVR, including for information technology (IT), may increase on circuits with higher DER penetration. While the company points to Exhibit A-9 to demonstrate that CVR is cost-effective, any changes to capital costs or energy savings could render the technology uneconomical. According to Mr. Becker, the company must perform a break-even analysis to determine the point when investment in CVR is unwarranted. Mr. Becker testified that the PCA and alternative plan contain CVR, and there are only limited

[401] Id. at 3428, referencing the September 24, 2021 order in Case No. U-20633, pp. 59-60.
[402] 8 Tr 3428-3429.

scenarios where CVR is not selected, but the company did not present an LCOE analysis for CVR in this case.[403]

Mr. Becker recommended that the Commission approve capital costs for CVR in this proceeding, provided that company meet the following conditions: (1) present a detailed stakeholder engagement plan and detailed analysis of public interest in CVR consistent with the February 24, 2021 order in Case No. U-20645, in a rate case or as part of this IRP; (2) Consumers shall determine the impacts of DERs on CVR enabled circuits as set forth in the order in Case No. U-20633; (3) Consumers must perform benchmarking to determine how to best analyze constant energy devices at the customer level and apply the results to capacity and energy reductions; and (4) Consumers shall undertake a break-even analysis that includes DER impacts and constant energy devices as well as potential additional capital investments to determine when CVR is no longer economical. The company should also be directed to continue annual reporting on CVR.[404]

Consistent with Mr. Proudfoot's general recommendation, Mr. Becker opposed preapproval of O&M costs for CVR. Mr. Becker further noted that although Consumers did not request an FIM for CVR, the company did include the cost of a CVR shared savings mechanism, based on 15% of avoided cost, in its modeling.[405] Mr. Becker highlighted that because the CVR FIM is based on cumulative savings, rather than annual spending, "[t]he incentive amount from 2022-2040 quickly surpasses the capital costs the

---

[403] Id. at 3433.
[404] 8 Tr 3431.
[405] Id. at 3431-3432; Exhibit A-87.

Company would spend on the CVR program[,]" adding that the incentive would be earned indefinitely, long after CVR investment ceases.[406]

Mr. Becker reiterated Staff's longstanding position that CVR is part of the company's grid modernization efforts, indeed CVR-type benefits were used by Consumers to justify the company's investment in grid modernization. Mr. Becker added that, unlike DR and EWR, marketing and customer engagement efforts are not necessary for an effective CVR program. Therefore, according to Mr. Becker, CVR should not qualify for an incentive and the Commission should find that the CVR FIM included in the modeling in this IRP is unreasonable. Thus, the Commission should direct the company to remove any CVR incentive from its modeling in future IRPs.[407]

Mr. Henry agreed that because there is currently little DER penetration on CVR enabled circuits, Consumers has not found any noticeable impacts. However, contrary to Mr. Becker's claim, Mr. Henry indicated that Consumers expects more CVR benefits as DERs become more predominant. Although the company has not undertaken a detailed analysis, according to Mr. Henry, "[a]s a result of the increased voltage from DERs, the CVR program would expect to achieve additional voltage reduction, which would lead to an increase in CVR load reduction benefits without requiring additional investment by the CVR program."[408]

Regarding the conditions for cost approval that Mr. Becker outlined, Mr. Henry testified that although Staff did not specify timing for a DER analysis, the company would include such an analysis in its next IRP if directed to do so. In addition, with respect to

[406] Id. at 3432.
[407] 8 Tr 3433-3434.
[408] 7 Tr 1725.

constant energy devices and end use load, Mr. Henry clarified that the CVR analysis does consider customer-level usage, albeit measured at the circuit level. Mr. Henry explained:

> [T]he data itself represents an aggregation of all loads connected to the circuit from every customer, including all of their constant energy devices as well as all other types of electrical appliances. The Company acknowledges that various electrical devices respond differently depending on the input voltage, as described in my Exhibit A-92 . . . pages 48 through 50. However, the Company does not have the capability to single out and determine usage from individual devices. The Company also does not have data regarding the type and quantity of electrical devices that are used by each of our customers. However, the advantage of the Company's CVR pilot methodology in implementing the Day On, Day Off method is that we are able to observe the load reduction behavior as an average across all customer devices. This methodology reveals the load reduction capability that the Company should expect from the typical customer moving forward.[409]

Mr. Henry also pointed out that Consumers engaged a third-party evaluator in 2021, who confirmed that the company's method for measuring CVR voltage and load reduction was appropriate. Nevertheless, Mr. Henry indicated that Consumers was willing to meet with Staff before the next IRP to further discuss constant energy devices and CVR analysis.

With respect to Staff's concerns about the break-even point for economical CVR, and its request for a break-even analysis, Mr. Henry responded that Consumers believes the analysis contained in Exhibit A-9 does contain the information on CVR economics. But, if the Commission requires an analysis in a different format, after consulting with the Staff, Consumers would provide such information. Mr. Henry further indicated that the company would provide details on a stakeholder engagement plan and public interest aspects of CVR in its next IRP, even though CVR is no longer a pilot program.[410]

[409] 7 Tr 1726.
[410] 7 Tr 1727-1728.

Concerning Staff's recommendation to approve only CVR capital costs and not O&M costs, Mr. Henry discussed the importance of O&M in maintaining CVR circuits, "[s]pecifically, the maintenance required to keep capacitor banks, voltage regulators, and their associated cellular communication infrastructure fully operational is a critical piece of CVR implementation and benefit realization[,]" noting that a significant amount of these costs are associated with labor to maintain the CVR program.[411]

The PFD finds Staff's position persuasive and recommends that the Commission approve the company's request for CVR capital costs as part of this proceeding, subject to the four conditions outlined in Mr. Becker's testimony. As discussed above, CVR O&M cost approval should occur in rate cases where these costs can be updated and more comprehensively evaluated. Finally, as noted above, while it is appropriate to include an FIM as part of the modeling of demand-side resources, the company should be instructed to include only the incentive amount consistent with the most recently approved FIM, and not the amount or mechanism the company aspires to. In the case of CVR, the Commission has not made any determination regarding whether this is the type of investment that qualifies for an incentive, or, if it does qualify, the way that the mechanism would be structured. Until the Commission makes a decision on an FIM for CVR, it is inappropriate to include an incentive in the modeling.

4. Battery Storage

In his direct testimony, Mr. Washburn discussed Consumers' plan to begin adding small-scale battery storage prototypes in 2025 as part of the PCA, as well as the modeling

[411] Id. at 1729-1730.

of the different storage options.[412] The prototypes Mr. Washburn discussed in detail include: (1) energy and capacity, (2) distribution asset upgrade deferral, (3) ancillary services market (specifically the performance of frequency regulation), and (4) solar plus storage.[413]

Although commending the company for improving its modeling of battery storage in this IRP, Mr. Matthews testified that Staff found the company's approach to adding battery storage insufficient, noting that Consumers will not be deploying significant amounts of storage until 2035.[414] Mr. Matthews testified that Staff recommends that the company move its initial investment in battery storage to 2025, rather than 2030, and that this proposal be modeled in conjunction with the retirement of Campbell 3.[415] Mr. Burgess and Mr. Rafson also raised concerns about the delay in battery storage investment.[416]

Although Consumers disputed that its PCA delays investment in storage until 2035, noting that it has already invested in a number of small-scale storage projects, the company proposed an alternative storage program, beginning in 2024, as part of its rebuttal. Mr. Blumenstock testified that Consumers agreed that moving its storage glidepath up to 2025 was feasible, and that the company is requesting approval of a battery deployment program to install localized batteries alone, or with solar, in areas "considered vulnerable or opportunistic in gaining quantifiable learnings of the benefits/consequences to the reliability, resiliency, and performance of the distribution

[412] 7 Tr 2038-2053.
[413] 7 Tr 2053. Although there were numerous criticisms of the company's initial proposal, the majority of the concerns centered on the company's failure to include significant battery storage before 2030. In response, the company presented a new program in rebuttal, which is discussed in more detail *infra.*
[414] 8 Tr 3624; Exhibit A-19.
[415] 8 Tr 3625.
[416] 8 Tr 3304; 8 Tr 3841.

system."[417] Mr. Blumenstock added that this new battery program will align with the low levels of on-peak load growth projected for EVs.

As shown in Figure 2 of Mr. Blumenstock's rebuttal, Consumers proposes to add five MW of storage in 2024 increasing to 40 MW in 2027, for a total of 75 MW of additional storage by 2027.[418] Mr. Blumenstock testified that the requirements for the battery deployment program (BDP) include:

> The Company will use the battery resources included in the program in isolation or in combination with the other resource sets identified in the PCA, (i.e. solar, EWR, DR);
>
> The battery resources, and any battery plus resource combinations, are to be owned by Consumers Energy to facilitate an expedited pace of installation and learnings;
>
> The Company will conduct an all battery RFP to develop the most economic battery projects. The RFP will consider Company bid resources as well as build-transfer agreements and other similar arrangements;
>
> The battery resources will not be used to set PURPA full avoided cost rates and therefore, will not be subject to the same competitive procurement guidelines as the IRP solicitations;
>
> The Company will have flexibility to procure solar plus storage options in the above discussed solicitations;
>
> The Company will have the flexibility to adjust amounts of annual battery deployment based upon economics of the bid proposals resulting from the RFP; and
>
> To the extent possible, siting of projects will be implemented in localized areas identified as providing potential benefits to the distribution systems' reliability, resiliency, and performance with a focus on vulnerable communities.[419]

[417] 3 Tr 203.
[418] 3 Tr 204.
[419] Id. at 204-205.

In surrebuttal, Dr. Sherman responded that EIBC/IEI/CGA do not fully support the BDP as formulated by Mr. Blumenstock. According to her, the near term deployment of battery storage and the addition of 75 MW of storage by 2027 are improvements over Consumers' original proposal; however, there are still concerns about: "(1) size of the program; (2) limitation to distribution-connected storage; (3) Company ownership of all of the new battery storage resources; (4) limitation of an all-battery request for proposals ("RFP") to only Company bids, build-transfer agreements ("BTAs") and 'other similar arrangements'; (5) the Company's position that it will not be subject to the same competitive procurement guidelines pertaining to IRP solicitations; and (6) the possibility that the BDP, as proposed, may include Company ownership of behind-the-meter ("BTM") storage resources."[420]

Concerning the size of the program, Dr. Sherman pointed to testimony by Mr. Burgess that the average result of Consumers' own analyses that showed that 80 MW of storage could be added by 2025, "and that between 80-230 MW of new storage could be viewed as a bare minimum 'no regret' option and could serve to offset a portion of the 2025 gas additions."[421] She further observed that Staff recommends that Consumers evaluate battery storage as part of modeling the retirement of Campbell 3 and that by limiting the program to only 75 MW "the Company does not address the totality of energy storage that can and should be added to meet the needs identified in the Company's IRP."[422]

[420] 8 Tr 3278.
[421] Id. at 3279.
[422] Id.

With respect to the proposal to limit storage interconnection to the distribution system, Dr. Sherman explained while there are significant benefits to distribution-connected storage, there are also important benefits to transmission-connected storage including the potential to provide capacity and a lower cost, thereby contributing to some of the company's capacity needs. Again, citing testimony by Mr. Burgess, Dr. Sherman noted that he found that a 4-hour, 60 MW battery would be cost competitive with Consumers' proposed gas plant purchases.[423]

Dr. Sherman testified that Consumers' proposal to limit battery storage to only company-owned projects, ignores the value of PPAs as part of a diverse and cost-effective portfolio. She also opposed the company's plan for the RFPs for batteries, which will be limited to company bids, BTAs, and other like arrangements. According to Dr. Sherman, although the Procurement Guidelines are mandatory for establishing PURPA avoided costs, the company should still conform its battery RFPs to the guidelines in order to receive the presumption that the investment is reasonable and prudent.[424] Finally, Dr. Sherman testified that it is unclear if Consumers intends to include BTM storage as part of the program, stating that the company's intent to use storage in combination with solar, EWR and DR suggests that the company is considering BTM storage. Dr. Sherman noted that the Commission has rejected previous proposals that the company own BTM storage and, in this proceeding, the Commission should make it clear that company ownership of BTM storage is not accepted.

---

[423] Id. at 3280.
[424] Id. at 3280-3282.

Consistent with Dr. Sherman's testimony, EIBC/IEI/CGA recommend that the Commission: (1) reject company ownership of BTM storage to the extent it may be included; (2) approve the BDP beginning in 2024 provided that the size of the program is increased, the Procurement Guidelines are followed, the program includes transmission-connected storage as well as distribution-connected storage, and at least 50% of storage capacity is obtained through PPAs.[425]

In response, Mr. Blumenstock explained that the three drivers for the company's battery program include: (1) the need for experience with battery deployment to prepare for larger distribution-connected deployments in the future; (2) the company's desire to increase the pace of battery deployment; and (3) the need for storage to offset the impact of EV load growth that may not have been included in the company's load forecast.[426] Mr. Blumenstock reiterated that, as demonstrated in the modeling, battery storage is still not an economical resource compared to other supply-side resources. Thus, it is reasonable to limit the size of the BDP in the near term. According to him, "[t]he goal with this deployment is not to add as many batteries as possible but rather to install the right amount of batteries to primarily address a conservative amount of additional EV growth while still allowing for an increased pace of battery deployment and obtaining valuable learnings about batteries."[427]

With respect to the company's proposal to limit deployment to distribution-connected batteries, Mr. Blumenstock acknowledged the economies of scale that transmission-connected batteries provide, but noted that Dr. Sherman "disregards the

[425] Id. at 3284.
[426] 8 Tr 3157-3158.
[427] Id. at 3158.

advantages of value stacking battery benefits, provides no evidence that distribution-connected batteries cannot also gain those economies of scale, and is not an example that is going to provide significant learnings to the Company beyond distribution-connected batteries."[428] He noted that an advantage of battery connection to the distribution system lies in the ability to locate batteries near areas with high EV adoption, thus providing the grid benefits that transmission-connected batteries cannot provide.

Mr. Blumenstock testified that company ownership of the batteries for this program is reasonable because it will allow Consumers to deploy batteries at a faster pace; it will allow the batteries to be located in areas where the company can best obtain experience in battery operation, and the company will be able to optimize the deployment and operation of the batteries without having to involve a third party.[429] Mr. Blumenstock dismissed concerns about the RFP process, testifying that the company will follow best practices and the RFPs will include third-parties under BTAs. As for Dr. Sherman's concerns that the program be subject to the Procurement Guidelines required under MCL 460.6t(6), Mr. Blumenstock responded that this issue is premature. According to him, the BDP is not in response to an immediate capacity need and thus Section 6t(6) does not apply. Finally, Mr. Blumenstock confirmed that the proposal in this case does not include BTM storage.[430]

In its brief, Consumers maintains that the Commission should reject the recommendations of EIBC/IEI/CGA for the BDP, on grounds that these recommendations do not further the purposes of the program, which are to increase the pace of battery

[428] Id. at 3158-3159.
[429] Id. at 3159.
[430] Id. at 3160-3161.

adoption, gain experience in battery use, and compensate for unanticipated EV load growth.[431]

Staff states that while it supports the company's proposal generally, it nevertheless recommends that the details of the program for 2024-2027 be addressed in a workgroup for interested parties and stakeholders.

Relying on Dr. Sherman's testimony, EIBC/IEI/CGA contend that the Commission should only approve the battery program if their recommendations regarding program size, exclusion of BTM resources, following the Procurement Guidelines, the inclusion of transmission connected storage in the program, and the acquisition of at least 50% of battery resources from PPAs are adopted.

The CEOs describe Consumers revised proposal as "a good starting point for discussion" noting that they agree with EIBC/IEI/GCA that the company should follow the Procurement Guidelines and that the Commission should be mindful of concerns about company ownership of BTM storage.[432]

MNS recommends that the proposal be adopted with certain conditions, namely: (1) the Commission should make clear that the approval of this program does not include any of the programs disallowed in Consumers' last two rate cases; (2) the Commission should specify that battery costs are generation and not distribution assets and should be classified as production costs for cost allocation purposes in rate cases; (3) the Commission should modify the company's ownership proposal to allow the company to own all batteries deployed in 2024-2025, but in 2026-2027, batteries should be subject to

[431] Consumers brief, pp. 257-258.
[432] CEO brief, p. 42.

RFPs that allow for both company and third-party ownership; and (4) because the proposed BDP does not contain any cost information, the Commission should make clear that approval of the program does not create a presumption that the costs are reasonable and prudent.[433]

In response, Consumers reiterates that the purpose of the program for 2023-2027 is limited and that the recommendations by Staff and other parties are unnecessary and should be rejected.

The PFD agrees with Staff that the details of the BDP, first presented in the company's rebuttal testimony, should be the subject of a stakeholder workgroup wherein issues concerning program size, grid interconnection, procurement method, and ownership issues can be comprehensively addressed. Alternatively, if the Commission finds that the proposed program is sufficiently detailed at this point, the Commission should approve the program subject to three of the four conditions proposed by MNS. The PFD finds that MNS's suggestion concerning the appropriate cost allocation of battery storage is a matter for a rate case and is outside the scope of an IRP.

F. Electric Vehicle Load

According to Consumers, for purposes of developing this IRP, the company assumed rapid growth (20% or more year over year sales increases) in EV adoption in Michigan, from a baseline of approximately 7,200 vehicles in the company's service territory when it began its modeling. Ms. Nielson testified that through the company's experiences with PowerMIDrive and PowerMIFleet programs, Consumers expects to be able to manage loads from significant residential and commercial EV adoption, noting

[433] MNS brief, p. 148.

that with rebates and customer education, 90% of residential EV owners are charging their vehicles off-peak.[434] Nevertheless, Ms. Nielson indicated that there remain many unknowns in the adoption of EV fleets, and the company will be closely monitoring changes through the PowerMIFleet pilot. Ms. Nielson summarized: "(1) residential EV adoption is still early but experiencing strong growth, (2) the Company has seen success with the current TOU rate and education based programs, but (3) fleet electrification is an emerging area that will better inform planning standards in the near future via PowerMIFleet learnings."[435] She added that fleet electrification could further advance residential EV adoption as drivers experience the benefits of EVs at work.

Staff witness Schiller testified that Consumers' starting point and near-term trends for EV adoption, based on vehicle registrations provided by the Michigan Secretary of State as well as national EV sales trends, were reasonable. However, Ms. Schiller raised a concern that Consumers has not developed a long-term plan for managing increased EV adoption, noting that the PowerMIDrive and PowerMIFleet programs may not be sufficient to offset EV load if EV adoption increases substantially.[436] Ms. Schiller cited Executive Order 14037 that President Biden signed in August 2021, that included a goal of 50% of new passenger vehicles and light trucks to be zero-emission vehicles by 2030, which might accelerate EV adoption. Ms. Schiller testified that in Consumers next IRP, the company should be directed to include an EV load sensitivity analysis in all modeling runs, including the 50% goal outlined by President Biden, as well as the highest EV

[434] 7 Tr 1955-1956.
[435] Id. at 1957.
[436] 8 Tr 3679-3680.

adoption rate feasible. In addition, Ms. Schiller recommended that the company provide the EV load impacts of its PowerMIDrive and PowerMIFleet programs in the next IRP.

On behalf of GLREA, Mr. Rafson testified regarding the potential for using EV batteries for storage under a vehicle-to-grid (V2G) program. According to Mr. Rafson, in addition to load shifting, V2G can provide peak load leveling, dispatchable power, backup power, and VAR injection. These services in turn could enable the matching of variable loads with variable generation, increase grid reliability and resilience, and decrease operating costs. Mr. Rafson further noted that even at modest levels of adoption, V2G storage could exceed the amount of pumped storage available at Ludington by 2030, and it could offset the need for the gas plants the company proposes to purchase. Accordingly, Mr. Rafson recommended that Consumers design a pilot program to test the services that V2G can provide, include V2G in grid design and resource planning, and develop a tariff to compensate customers for participation in V2G.[437]

In rebuttal, Ms. Nielson agreed in part with Ms. Schiller and Mr. Rafson. She testified that circumstances have changed significantly in EV adoption since the company developed its PCA. Citing recent announcements by major automakers, and noting that on November 4, 2021 Consumers announced its commitment to powering one million vehicles by 2030, Ms. Neilson testified that the company's EV projections are low, and that based on updated projections and customer behavior, Consumers could see a total load increase of 4.5 million MWhs, 0.7 million MWh of which will occur during on peak hours and 3.8 million MWhs during off-peak hours in 2030.[438]

---

[437] 8 Tr 3835-3839.
[438] 7 Tr 1963.

Ms. Nielson agreed with Staff that in the company's next IRP, it will update its EV forecast and provide sensitivity analyses at different levels of EV load growth. In addition, Consumers will provide the results of its PowerMIDrive and PowerMIFleet pilot programs.[439]

In response to Mr. Rafson's recommendations, Ms. Neilson agreed that there are potential benefits to V2G integration that should be explored; however, at this point, the company cannot predict whether customers would participate in V2G programs or the amount of storage that might be available to offset supply-side resources that are needed in the short term.

This PFD finds that Consumers adequately addressed EV integration in this IRP. As Consumers admits, adoption of EVs is occurring more rapidly than the company assumed in developing its PCA one and a half years ago. The company states that it will provide an updated forecast and additional sensitivity analyses in its next IRP.

Although Consumers believes it is too soon to evaluate V2G potential, and that V2G is not sufficiently developed to offset any capacity need in the plan period, the company could consider presenting a limited (i.e., one circuit or sub circuit) V2G pilot in its next IRP. At the very least, Consumers should be directed to provide testimony on its assessment of the potential for V2G in a future IRP.

G. Accounting and Other Approvals

1. Cost Recovery for Retiring Units

Consumers requests regulatory asset treatment, with full return on, the net book value of the retiring units, emphasizing that it cannot proceed with the PCA absent the

[439] Id. at 1964.

requested approval. Mr. Watkins calculated that the unrecovered book balance for the retiring units is $112 million for Karn 3 and 4, $514 million for Campbell 1 and 2, and $924 million for Campbell 3, totaling approximately $1.5 billion as of December 31, 2022.[440] Mr. Coker presented the company's proposal for recovery of the remaining book value of the units along with decommissioning costs. In summary, Consumers states:

> The Company proposes to continue to depreciate Karn Units 3 and 4 and Campbell Units 1, 2, and 3 at Commission-approved depreciation rates until the Commission resets base rates in the Company's next electric general rate case. 7 TR 1604. In the Company's next rate case after the conclusion of this IRP, the actual remaining net book value would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. The Company proposes that the Commission set an annual amortization rate that allows for the recovery of the remaining net book value and the decommissioning costs through May 2031 for costs associated with Karn Units 3 and 4 and Campbell Units 1 and 2 and through May 2040 for costs associated with Campbell Unit 3. 7 TR 1604-1605. In its next electric depreciation case, the Company would expect to remove Karn Units 3 and 4 and Campbell Units 1, 2, and 3 from the analysis to reflect the fact that those assets will be, or already were, moved to a regulatory asset. 7 TR 1605.[441]

Mr. Maddipati discussed alternative methods to recover the remaining book balance of the retiring plants, including accelerated depreciation to recover the balances and decommissioning costs before the plants are retired. He testified that this proposal was rejected because it would require a significant rate increase before 2025 resulting in a substantial burden on customers.[442] Mr. Maddipati testified that the company also considered securitization of the remaining book value of the retiring units, but it rejected this option as well. According to Mr. Maddipati, like PPAs, "a securitization creates a long-term financial obligation that has an impact on the credit of the Company. Unlike

[440] 7 Tr 2069; Exhibit A-32.
[441] Id. at 321-322; Exhibit A-37.
[442] 5 Tr 950-953.

PPAs, however, securitization debt is included on the Company's balance sheet and therefore its impact on the Company's capital structure is readily observed[,]" noting that "Moody's includes securitization debt as part of the capital structure of the company and includes the securitized debt in the corporate rating analysis despite being considered non- recourse debt. This inclusion of securitization debt adversely impacts the Company's corporate rating."[443]

Mr. Maddipati discussed the historical use of proceeds from securitization, to pay down debt and equity in equal portions, testifying that, "[w]hile that may have been reasonable when the balance of securitization debt was relatively modest (such that the capital structure remained balanced when including securitization) as in the case of the Classic 7 securitization, the magnitude of incremental securitization debt that additional securitization financings would place on the Company's balance sheet skews the relative balance of debt and equity."[444] Mr. Maddipati indicated, however, that the impacts of securitization could be addressed through adjusting the company's capital structure, as shown in Exhibit A-35.

With respect to the company's proposal to earn a full return on the retiring units, Mr. Maddipati again referenced the need for strong credit ratings, emphasizing that "[o]ne of the key criteria used by rating agencies is the quality of a utility's regulatory environment and as noted by both Moody's and S&P, the recovery of investments and the ability to earn a reasonable return are key components of that analysis[.]" He added that, "[t]o the extent the Company is forced to take an impairment on investments that were previously

[443] 5 Tr 955-956.
[444] Id. at 956; Exhibit A-37.

deemed reasonable and prudent, such an action would raise serious questions regarding the stability of Michigan's regulatory environment and ultimately negatively impact or raise the Company's long-term financing costs, thereby discouraging future investments."[445]

HSC supports the company's recommendation that the unrecovered book balances for the retiring units be recovered through a regulatory asset rather than through securitization. Mr. Feldman testified that the consequences of using securitization financing include: risk compression (i.e., shifting risk from securitization bond holders to the utility and investors); write-offs of prudently incurred investments resulting in impairment; intergenerational equity issues resulting from cost shifts; repeated usage of securitization resulting in the company being locked out of the securitization market in the future; and the creation of uncertainty for investors when prudently incurred investments do not receive a return for the full life of the asset.[446] Mr. Feldman further explained that Consumers' ratio of securitized debt to net electric plant of 8.51% would increase to 23.12% if the net book value of the retiring plants were also securitized, a percentage that is significantly higher than any other utility that has securitized retired generation plants.[447]

While Staff does support regulatory asset treatment for the remaining book balances of the retiring plants, it does not take a position on the appropriate return on the net book value of these units. According to Staff, the Commission has a number of options including: (1) regulatory asset treatment with a return at the short-term or long-term debt cost rate or some other rate the Commission finds reasonable; (2) regulatory asset treatment with no return; (3) regulatory asset treatment contingent on securitization;

[445] 5 Tr 952-953.
[446] 7 Tr 2244-2245.
[447] 7 Tr 2252-2253; Figures 5 and 6.

(4) amortization periods other than the remaining design lives of the retiring units; or (5) some other option.[448] Mr. Nichols sponsored Exhibit S-8.18, which shows the cost of different rates and amortization periods for each retiring unit. Staff points out that "the Commission could approve any number of rates and periods, and the exhibit shows a few possibilities."[449]

Staff notes that although the company is not recommending securitization, Mr. Maddipati explained that if the net book balances are securitized, the securitized debt could be included in Consumers' capital structure. Alternatively, Staff suggests that the Commission could adjust the company's return on equity (ROE). In any event, Staff recommends that any modifications to capital structure or ROE be made in a general rate case where the Commission can consider all factors.[450]

The Attorney General contends that, contrary to Consumers' claims, ratings agencies do not consider securitization a credit negative, and that securitization of retired generating units is not uncommon. Pointing to Dr. Dismukes' testimony, the Attorney General argues that even if the NPV of the benefits of securitization becomes negative, the Commission could consider securitizing only a portion of the retirement costs.[451]

MNS and ABATE both support securitization of the unrecovered book balance of the retiring units. MNS recommends that the Commission authorize Consumers to establish a regulatory asset but direct the company to file a securitization case, noting that recovery through securitization would save ratepayers approximately $273 million

[448] Staff brief, p. 104.
[449] Id.
[450] Id. at 106.
[451] Attorney General brief, pp. 16, 20, citing 7 Tr 2095-2099.

compared to the company's proposal.[452] ABATE contends that the amortization of any regulatory asset, if approved, should not begin until the first rate case after the asset is retired. ABATE adds that because the retired assets will not be used and useful in the provision of utility service, it would be imprudent to permit Consumers to earn a return on them. Moreover:

> Beyond the imprudence of the Company's proposal, the carrying charge issue is a revenue requirement matter pertaining to retired resources, meaning it does not (and should not) need to be resolved in this IRP proceeding. The Commission should instead review and assess this issue once the amount of the regulatory asset and the regulatory liability described above are known and measurable. (7 Tr 2821.) Indeed, the issue of a carrying charge for these amounts is not relevant until Consumers establishes an amortization period for the regulatory asset net of the regulatory liability (net regulatory asset). (Id.) The amortization of the net regulatory asset should not occur until Consumers files a rate case following the retirement of the plants. At that time, depending on the value of the net regulatory asset, the carrying charge can be finalized and options (such as securitization) can be analyzed.[453]

The UCC asserts that while the Commission may approve recovery of the remaining book balance of the retiring units, it would be unjust and unreasonable to permit the company to earn a full return on the retired units. UCC adds that the Commission could allow some limited return on the assets if there were concerns that the company's financials might be impaired.[454] The UCC points out that Consumers proposes to earn a full return on the retiring units as well as a full return on the resources it plans to acquire under the PCA, contending that "[t]his goes too far . . . [t]he just and reasonable outcome is for Consumers to recover the book value of its existing plants while getting a rate of return on new facilities[.]"[455]

[452] MNS brief, p. 136, citing 7 Tr 2610.
[453] Id. at 33-34.
[454] UCC brief, pp. 8-9.
[455] Id. at 12-13.

For two reasons, this PFD finds that, while approving regulatory asset treatment is reasonable (for now) for the units retiring in 2023, the issue of an appropriate return on the net book value of the retiring units, as well as whether some or all of the costs should be securitized, should be addressed in another proceeding.

First, this PFD finds that, consistent with the arguments made by Consumers and Staff regarding the interpretation of MCL 460.6t(11), the statute requires the Commission to "specify the costs approved for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan." The costs for which the company requests preapproval, namely the recovery of net book value and return on the retiring units, are clearly not "investments or resources used to meet energy and capacity needs." As such, the statutory scheme governing IRPs does not include the preapproval of recovery of sunk costs for retiring assets, even if those costs may be incurred in the next three years.

Second, the record on this issue is simply not sufficiently developed to allow for a reasoned decision. Several parties recommend securitization, but Consumers and HSC oppose this cost recovery mechanism on several grounds, including that additional asset securitization would affect the company's credit metrics. However, Staff's Exhibit S-8.18 provides an array of choices, on a unit-by-unit basis, that is a starting point for evaluating the most reasonable and fair approach to addressing cost recovery for the retiring units. As Dr. Dismukes pointed out:

> It should be noted that the instant docket is fundamentally about the appropriateness of the Company's integrated resource planning. The

> Company has chosen to include a number of related issues, including a request for Commission approval to retire certain generation units early and replace the lost capacity with new resources. The issue that the Company raises regarding a securitization threshold could be handled in a future proceeding. While I believe the Commission can fully securitize the remaining unrecovered costs associated with the to-be retired coal plants, it should be noted that the Commission would not face a binary choice in a future proceeding. If, as the Company suggests, there is some point at which the net present value of the benefits from securitization would become negative, ratepayers might still benefit from the securitization of some portion of the $1.7 billion in plant retirement costs. In fact, the Company provides an example of the Wisconsin Public Service Commission's combined use of securitization and regulatory asset treatment to recover the early retirement costs associated with Wisconsin Electric Power Company's Pleasant Prairie coal-fired plant.[456]

Consistent with the above discussion, this PFD recommends that the Commission direct Consumers to file, in a separate contested proceeding, a proposal for cost recovery of the unrecovered book balance of the units approved for retirement in this proceeding, including proposals for securitization of some or all of the retiring units and recommendation for a just and reasonable return on the unrecovered balances.

2. Decommissioning Costs

Mr. Watkins testified that there are approximately $381 million total in decommissioning and coal ash disposal costs for the retiring units and other units that were retired previously.[457] Noting that, in the December 9, 2021 order in Case No. U-20849, the Commission approved a settlement agreement removing decommissioning and ash disposal costs from the company's depreciation rates for previously retired units,[458] Consumers points out that the settlement agreement and order do not address

[456] 7 Tr 2100.
[457] 7 Tr 2070; Exhibit A-33.
[458] These units include Karn 1 and 2; B.C. Cobb plants, J.R. Whiting plants, and J.C. Weadock plants. Consumers brief, p. 321.

ash disposal and decommissioning costs for the units proposed to be retired in this case. Consumers therefore requests regulatory asset treatment for these costs.

Staff recommended an alternative to the company's proposal, noting that it agreed with the company's request for regulatory asset treatment of decommissioning costs for the retiring units. However, Staff recommended that the company record a regulatory asset for actual decommissioning spending for the retiring units, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Consumers agreed this was reasonable.[459]

This PFD finds that Staff's recommended accounting treatment for decommissioning and ash disposal costs should be adopted.

3. Transition Costs and Plans

a. Transition Costs

Consumers also requests approval in this case of regulatory asset treatment for transition expenses for the Karn and Campbell sites, with the amortization period to be established in a future rate case, and with the unamortized balance included in rate base.[460] Consumers also requests approval of regulatory asset treatment for the retention and separation plan for Campbell.[461]

Staff opposes regulatory asset treatment for these expenses. Mr. Nichols testified that the Commission could approve the deferral of employee retention cost and retirement transition costs here; alternatively, the Commission could consider these requests in a

[459] Consumers reply brief, p. 121; Exhibit S-8.11.
[460] 7 Tr 1609.
[461] Id. at 1610.

general rate case.[462] Noting that the Commission approved regulatory asset treatment for Karn 1 and 2 retention and transition costs in Case No. U-20697, a rate case, Mr. Nichols highlighted that the approved expenses "[were] not for the entire amount requested and not for the entire retroactive period-of-time requested. Additionally, the regulatory asset was approved with a cap of $14,394,000." Mr. Nichols added that, "[i]n the past, the Commission has generally not approved 'blank check' regulatory asset treatment and in the instant case it is unclear what dollar amount the company is requesting for regulatory asset treatment."[463] Mr. Nichols testified that it may be more appropriate to request regulatory asset treatment in a rate case where the costs can be scrutinized.

ABATE likewise opposes the company's request on grounds that the request is beyond the scope of an IRP. In addition, ABATE contends that because transition and retention costs are not part of utility service, there should be no carrying charge, and total costs should be split between ratepayers and the company.[464]

Consumers responds that Staff misunderstands the company's request, and that the company is not requesting a regulatory asset in a specific amount or for a specific period, simply approval to defer the costs until they can be reviewed and approved in a rate case.

Staff insists that "only providing a high-level generalized narrative to support an estimated $60 million in employee retention costs and providing ***no*** cost estimate for the

[462] 8 Tr 3646.
[463] Id.
[464] ABATE brief, p. 34.

retirement transition costs is insufficient to support approval of the company's requested regulatory asset treatment."[465] Staff therefore recommends the request be denied.

This PFD agrees with Staff that, unlike decommissioning and ash disposal costs, Consumers has not provided sufficient detail on employee retention and transition costs for approval in this proceeding. Consumers may request cost recovery for these costs in a future rate case.

b. Transition Plans

Mr. Kapala testified regarding Consumers' plans for community transition in the areas where units are proposed to retire. Mr. Kapala explained that retirement of the Karn and Campbell units will have impacts on employment and tax base in the affected communities.[466] In order to assist these communities:

> The Company will develop a community transition plan that analyzes the economic strengths and weaknesses of the community that will affect the transition after the units are retired, as well as potential threats to the transition. This community transition plan will be closely coordinated with a communications strategy that will ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company has commissioned a detailed future-use study to analyze specific potential opportunities to redevelop the Karn site.[467]

Noting that it appears likely that all four Karn units will be retiring in 2023 as well as the Campbell units in 2025, Mr. Comings testified that it is not clear whether Consumers intends to wait for the outcome of this case to move ahead with updating the transition plan at the Karn site, noting that the retirement date for the Karn units will be less than a year after this case is completed. Mr. Comings therefore recommended that the Commission direct Consumers to submit a community transition plan for the Karn

---

[465] Staff brief, p. 22.
[466] 7 Tr 1794-1795.
[467] 7 Tr 1795.

location within 150 days of the final order in this case, to direct Consumers to make its Karn community transition plan public, and to engage in robust transition planning for in anticipation of the Campbell retirements in 2025. Mr. Comings also urged the Commission to order Consumers to develop and submit a study for the reuse of the Karn site.[468]

Staff witness Gibbs recommended that Consumers include residents of the affected communities in the decision-making process and that the company begin outreach to community members immediately, rather than awaiting approval of the company's PCA. Referencing the potential decrease in tax revenue in the communities where plants are retiring, Ms. Gibbs also recommended that Consumers investigate the prospect of clean energy opportunities in the affected communities to mitigate the impacts of lower tax revenues.[469]

Mr. Cira-Reyes echoed these concerns that there was insufficient community involvement in transition planning, suggesting that community organizations be extensively involved in outreach and planning, highlighting the barriers that low-income communities and communities of color face in energy policy decision-making.[470]

In rebuttal, Mr. Kapala agreed in part with Mr. Comings and Ms. Gibbs. Mr. Kapala testified that since Consumers announced the IRP, the company has met with Karn and Campbell stakeholders to understand their concerns and "to re-imagine their communities" as part of the company's future-use planning.[471] Mr. Kapala added that the

[468] 8 Tr 2954.
[469] 8 Tr 3520.
[470] 7 Tr 2540, 2521-2522.
[471] 7 Tr 1814.

company has already begun discussions with community leaders in the Campbell location as it begins transition planning for that site.[472]

Mr. Kapala disagreed with Mr. Comings' recommendation that the transition plan for the Karn site should be made public, citing concerns about commercially sensitive information, and the fact that the transition plan is not finalized and are still subject to change. According to him, "[a]s a result, the Company may be unable follow through on certain aspects of its plan, thereby requiring the development of an alternate plan. The Company must balance its needs with the needs of the community, and it would not want to communicate any redevelopment which could jeopardize its success."[473] Mr. Kapala further testified that Consumers expects to complete the transition plan for the Karn site in the first quarter of 2023, adding that the timeline was reasonable given the need to complete a future use study and update the company's transition plan. Mr. Kapala recommended that the Commission reject Mr. Comings' recommended 150 day timeline to complete the future use study.[474]

Citing the Commission's May 8, 2020 order in Case No. U-20561, MNS observes that the Commission recognized the importance of transition planning and community stakeholder involvement in locations where coal plants are retiring. In that order, the Commission directed DTE Electric to develop and file a comprehensive community transition plan, including plans for employees, impacts on the local tax base, and site remediation in that company's next rate case. MNS contends that Consumers should be directed to follow the same process in planning the transition for the Karn and Campbell

---

[472] 7 Tr 1813.
[473] 7 Tr 1812.
[474] Id.

sites.[475] MNS points out that Consumers intended to update its plan for the Karn location in 2020, but to date, that has not happened, and as of now, there is no timeline for completing that update. MNS adds that, "[t]he Company's community transition efforts . . . have been marked by significant delays and a puzzling level of secrecy that threaten to foreclose transparency and meaningful opportunities for public engagement in advance of the retirement of the Karn units."[476]

In response to Mr. Kapala's rebuttal, MNS points out that Consumers' intention to update its transition plan for retirement by the first quarter of 2023, is only a few months before the actual retirement date, giving little time for public review and input. Again pointing to the order in Case No. U-20561, MNS notes that the Commission directed the DTE Electric to file a community transition plan four and a half months later, and eight months before the plant's planned retirement date. MNS urges the Commission to adopt a similar timeline here. Finally, MNS takes issue with the company's refusal to make its transition plan public, arguing that although there are aspects of the plan that may be business-related, in the end it is still a <u>community</u> transition plan, and not a business plan.[477]

Staff also raises concerns that there is insufficient community involvement in the company's transition planning and that the affected communities should be involved in planning as early as possible. Staff reiterates its recommendation that the company consider mitigating community impacts through clean energy resources.[478]

---

[475] MNS brief, p. 143.
[476] Id.
[477] Id. at 144.
[478] Staff brief, pp. 132-133.

The UCC recommends that the company undertake better planning to ensure a just transition for the communities and workers affected by the retirements. The UCC recommends that the Commission direct the company, in its next IRP, to include site redevelopment plans for both the Karn and Campbell sites.[479]

In response, Consumers urges the Commission to reject MNS's recommendation to require the company to file an updated plan within 150 days of the final order in this case. The company argues that Case No. U-20561 involved a different utility and different circumstances that do not apply to Consumers. Consumers avers that it already has a plan in place for the retirement of the Karn units, including an economic development study and a future use study. The future use study will be updated to include the retirement of all four units and will be completed in the first quarter of 2023. Consumers also objects to making the transition plan public, citing Mr. Kapala's rebuttal testimony.

The PFD agrees with MNS, that Consumers should be directed to file a draft, if not final, community transition plan for the Karn location within 150 days of the Commission's final order in this case. In addition, Consumers should be directed to provide an overview of past and future community engagement efforts, including how community concerns have been incorporated into the plan to date. The PFD also agrees with MNS that while there may be some commercially-sensitive information contained in the plan, which may be redacted, it is important for transparency that the transition plan be made public to the extent possible.

---

[479] UCC brief, pp. 13-15.

H. Competitive Procurement

As set forth in Mr. Blumenstock's and Mr. Troyer's testimony, Consumers intends to continue competitive procurement of solar resources annually under the PCA. Per the settlement agreement in the company's previous IRP, Consumers: (1) uses an independent evaluator to administrator the solicitations; (2) the company makes provisional awards based on blind rankings of the proposals; (3) QFs are permitted to bid any technology into the solicitations; (4) value-added criteria are added to the net cost; (5) the solicitations follow the 2008 Guidelines for Competitive Request for Proposal of Renewable Energy and Advanced Cleaner Energy set forth in the December 4, 2008 order in Case No. U-15800, including the issuance of public notice of the solicitation and terms of the contract; (6) bidders may choose a PPA term length up to the depreciable life of a similar company-owned asset; (7) 50% of capacity acquired may be company owned and at least 50% must be capacity from PPAs; and (8) bidders must be informed of the effect of the FCM on PPA proposals.[480]

Consumers states that based on competitive solicitations undertaken in 2019 and 2020, the company is recommending "improvements [that] would allow for increased flexibility in the solicitation process as well as greater certainty regarding the Commission approval process for the new resources selected."[481] The following issues were raised with respect to the company's proposed changes to competitive procurement: (1) the limitation on the amount of solar solicited annually; (2) the elimination of value-added criteria from bid evaluations as well as changing the bid evaluation criteria; (3) the amount

[480] Consumers brief, pp. 358-359; citing 4 Tr 683-684.
[481] Consumers brief, p. 360.

of new capacity the company will own versus third party ownership; (4) length of PPA contracts; and (5) the FCM and proposed changes thereto. These issues are addressed below.

1. Size of Solar Solicitations

In its modeling, Consumers assumes that the company will add no more than 500 MW of solar per year. Mr. Battaglia testified that an incremental approach is reasonable because it anticipates technological advances in the early years of the plan that can reduce costs; the approach will allow the company to gain experience in development, construction, and operation of solar facilities in the near term, and this approach will allow the company to apply its experience to improve solar performance and lower costs.[482] Mr. Battaglia added that while the modeling assumes solar additions of 500 MW per year, the company is requesting increased flexibility to add more or less than that amount annually, depending on costs, value, and effects on the company's financials.[483]

Mr. Jester testified that absent the 500 MW constraint on solar acquisition, more solar may have been selected for the PCA, noting that in the illustrative modeling performed by Mr. Evans, 780 MW of solar were selected in 2025, with minimal additions until 2030 when the contract with Midland Cogeneration Venture (MCV) ends. In all, Mr. Evans' modeling showed the addition of approximately 707 MW per year of solar capacity.[484]

Mr. Jester testified that the amount of solar in the MISO Generator Interconnection Queue, as well as the amounts offered in response to the company's competitive

[482] 5 Tr 1181-1182.
[483] Id. at 1182.
[484] 7 Tr 2598.

solicitations, indicate that substantially more solar generation is available than the 500 MW that the company proposes to acquire annually. Mr. Jester observed that the MISO queue has 11,323 MW of transmission-interconnected solar projects in the Lower Peninsula with in-service dates before 2025, including 7,134 MW of solar with in-service dates in 2023.[485] In addition, referencing Mr. Troyer's testimony, Mr. Jester explained that in 2019, Consumers issued an RFP for 300 MW of solar to be installed by 2022 and the company received proposals for 34 projects totaling 2,000 MW. Similarly, in 2020, Consumers again solicited 300 MW of new solar and received responses from 43 projects totaling 2,500 MW. According to Mr. Jester:

> The fact that the solar capacity that was offered in response to Consumers RFPs was more than six to eight times the quantity that Consumers sought indicates that the Company could have readily acquired more than the 300 MW sought. Indeed, it suggests that Consumers could have acquired well more than 500 MW in each of these solicitations. I further suggest that because solar developers will engage in the development process with some consideration of the likelihood of successfully selling the resulting project or its output, an increase in Consumers' announced rate of acquisition of new solar would also be likely to produce an increase in the amount of new solar development that is undertaken and could be offered to Consumers.[486]

MNS contends that the 500 MW cap on solar acquisitions is unreasonable, and the Commission should direct the company to modify the PCA to include solicitations of up to 750 MW of new solar for 2023-2025. MNS argues that if Consumers finds the cost of that amount of solar excessive, the company could present the results of its solicitation to the Commission, and it could limit the amount of solar energy it acquires.

---

[485] 7 Tr 2599-2600; Exhibit MEC-11.
[486] 7 Tr 2601.

On behalf of GLREA, Mr. Richter likewise testified that the 500 MW annual cap on solar acquisition was unreasonable, highlighting the fact that in response to the company's first solar RFP, Consumers received bids for nearly 2,000 MW of capacity.[487] GLREA recommends that the Commission direct Consumers to solicit up to 1,000 MW of new solar in its annual solicitations.

In rebuttal, Mr. Battaglia disagreed that an increase from 500 MW to 750 MW of solar would be reasonable. According to him, "[a] solar acquisition rate above 500 MW annually would increase solar developments risks toward: appropriate site selection, increased land acquisition, continued building of positive community relationships, additional resourcing toward successful community education, additional environmental impact studies, successful permitting, [and] arranging for additional electrical interconnection (MISO queue rates)," among other concerns.[488]

Mr. Troyer further explained that the company has noticed an increase in delays in project development, pointing to Consumers' contract with River Fork Solar that was delayed 16 months due to the need for transmission upgrades. Mr. Troyer added that several QFs have had challenges in meeting construction schedules, and supply chain issues have recently arisen, adding to the risk to the company's capacity position if projects are not completed on time.[489]

In response, MNS acknowledges that:

> [The concerns] raised by Company witnesses Battaglia and Troyer are reasonable, but they do not undercut Mr. Jester's ultimate recommendation that Consumers should solicit up to 750 MW of solar. The Commission must not allow reasonable concerns about uncertainties in solar development to lock Consumers into the self-fulfilling 500 MW cap that MNS witness Jester

[487] 8 Tr 3781.
[488] 5 Tr 1218.
[489] 4 Tr 761-762.

> described. On cross, Mr. Battaglia agreed that if Consumers issued an RFP for up to 750 MW of solar, the Company would not be obligated to acquire all of that capacity. On the other hand, if Consumers assumes it cannot acquire more than 500 MW of solar and therefore caps its solicitations, then the Company will never acquire more than that amount and could be forced to seek out other resources that are less clean and riskier in the long run.[490]

In response, Consumers reiterates that a larger solicitation increases myriad construction and development risks, and it increases the possibility that future solicitations will be unsuccessful. Consumers maintains that MNS's position is not supported by the record. Consumers adds:

> As conceded by MNS witness Jester, "MISO's seasonal construct will allow recognition of the comparatively high capacity value of solar in summer while recognizing that solar makes little or no contribution during nighttime winter hours when winter peak loads occur." 7 TR 2635. As demonstrated by Exhibit A-149, the Company will need other, controllable sources of generation besides solar to meet its winter capacity needs after the MISO seasonal resource adequacy construct is implemented, such as the natural gas plants the Company is proposing to purchase in this case. Increasing the Company's acquisition of solar resources will not help the Company meet its winter capacity needs in the MISO seasonal resource adequacy construct, particularly when the acquisition of solar is at the expense of any of the proposed gas plants purchases. It is far better from a risk implementation and capacity planning perspective for the Company to take a measured approach to new solar implementation by implementing its reasonable limit of 500 MW per year as part of the PCA and limit its exposure to overreliance on larger blocks of solar in the PCA.[491]

This PFD finds MNS's position persuasive, noting that it also appears to solve the ownership issue discussed below. As MNS argues, although many projects may never be built, Consumers' decision to set its annual solar acquisition amount at 500 MW appears arbitrary given the significant amount of solar in the MISO interconnection queue and the amounts that were offered in response to the company's RFPs in 2019 and 2020.

[490] MNS brief, p. 103.
[491] Consumers' reply brief, p. 217.

The PFD agrees that Consumers' 500 MW limitation could become self-fulfilling, even if additional cost-effective solar is available. And, again as MNS points out, Consumers would be under no obligation to purchase 750 MW of solar if it would be unreasonable or imprudent to do so. Accordingly, the PFD finds that the cap on annual solicitations for solar energy should be set at 750 MW, with the understanding that the company is not obligated to procure the maximum amount.

2. Bid Evaluations and Value-Added Criteria

Consistent with the settlement agreement in Consumers' previous IRP, Mr. Troyer testified that Consumers first screened its bids on the basis of viability including size of capacity offer, interconnection status, location site control, among other criteria. Projects were then ranked based on total projected costs (including FCM), total projected value, and value-added criteria to result in an adjusted net cost of the proposal.[492]

Based on recommendations from its third-party evaluator and the company's experience with the 2019 and 2020, Consumers proposes to change its bid evaluations from ranking the proposals on a net-cost basis to a cost-to-value ratio and establishing the value-added criteria on a points rather than $/MWh basis. According to Mr. Troyer:

> The net cost concept does not appropriately scale with the changes in cost and value if the two factors move substantially. There are other metrics that should be considered such as cost to value ratios. For example, if Proposal A has a cost of $95/MWh and a value of $100/MWh, the net cost (value) is ($5)/MWh; and if Proposal B has a cost of $45 and a value of $50/MWh, the net cost (value) is ($5)/MWh. However, if the value is based on a volatile commodity, the lower risk project is likely Proposal B since Proposal A relies on a higher estimated value. Using this example, Proposal A would have a cost to value ratio of 95% and Proposal B would have a cost to value ratio of 90% which means that Proposal B is the preferred project using the cost-to-value ratio methodology.[493]

[492] 4 Tr 686.
[493] Id. at 698.

* * *

> Second, in the 2019 through 2021 solicitations the Company established all non-pricing factors as Value Added Criteria on a $/MWh basis which was more divisive than traditional points-based evaluations for unique properties of a proposal. Similarly, to address some of the qualitative aspects of a project including development progress and project risk, the Company increased the screening criteria for eligible proposals. As the Company is seeking more flexibility on the timing of CODs in each proposal, it is unlikely that a robust screening criterion will be flexible enough to handle the variety of developmental status that will be bid into the solicitation. The Company supports transparency in the solicitation process for respondents to understand how proposals will be evaluated, but this transparency must be balanced with the Company's ability to improve the evaluation process through the flexibility to adopt best practices from the utility and C&I procurement processes.[494]

Staff does not oppose these changes, provided that they are clearly explained in the RFP using the process set forth in Section 2(b) of the Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Procurement Guidelines).[495]

EIBC/IEI/CGA recognize the concerns regarding the $/MWh factor for value-added assessments but argue that the value-added criteria must be transparent to all bidders. Specifically, the company should make clear the point value of each criterion. Highlighting the importance of competitive solicitations in procuring resources, EIBC/IEI/CGA recommend that the Commission only approve the PCA if the company agrees to implement the Procurement Guidelines adopted in Case No. U-20852.[496]

Mr. Jester recommended that the Commission rely on the Procurement Guidelines for now and reevaluate those guidelines in a later stakeholder process, rather than making changes here.

---

[494] Id. at 699.

[495] 8 Tr 3560-3561. See, September 9, 2021 order in Case No. U-20852.

[496] EIBC/IEI/CGA brief, p. 60.

HSC witness Rausch testified that Consumers should expand the use of bid qualifications and value-added criteria to include specific components including environmental, social, and governance factors with respect to assessing supply chain issues in solar development. He pointed to embedded carbon, labor conditions, and reliability of the supply chain to deliver essential parts for solar development.

HSC recommends that the Commission direct the company to include: (1) lifecycle carbon emissions in the manufacture of solar equipment; (2) labor conditions; and (3) reliability and resiliency of the supply chain in evaluating solar bids, noting that there are independent entities that measure and verify lifecycle carbon and labor conditions. According to HSC, given the amount of solar the company plans to add to its system, steps must be taken to create a more sustainable solar supply chain."[497]

In the September 9, 2021 order in Case No. U-20852, the Commission made clear that the Procurement Guidelines are not rules and are therefore not intended to be mandatory. However, the Commission also acknowledged that if a utility follows the Procurement Guidelines in an RFP, "it will receive the benefit of a presumption that its resulting procurement in accordance with the guidelines is reasonable and prudent[,]" clarifying that, "the guidelines are intended to set out a standard for the Commission's expectations of a fair, transparent, non-discriminatory bidding process."[498] Thus, although a utility may deviate from the Procurement Guidelines the Commission will require additional evidence that the resulting decision is reasonable and prudent. Given the Commission's preference for the use of the Procurement Guidelines, and the

[497] HSC brief, p. 9.
[498] Order, p. 24.

presumption of reasonableness embodied in that preference, the PFD finds that EIBC/IEI/CGA's recommendation that the company be required to use the guidelines should be rejected.

The PFD does agree with Staff that, with respect to value-added criteria, the evaluation criteria used should be transparent to all bidders. And, Consumers should carefully consider HSC's recommendation to include objective criteria for lifecycle carbon and labor conditions, both of which can be, or are, certified by an independent party.

3. Ownership Structure

Consumers proposes to change the 50% company owned, 50% PPA ownership structure from the settlement agreement in Case No. U-20165. Mr. Troyer explained that:

> The Company is challenged to balance the "lumpiness" of achieving a target capacity to the exact MW with resources as large as 150-200 MW in size. Finding the perfect blend of projects to get an exact amount of capacity (e.g. 300 MW) is not a simple or easily repeatable process. Further, the Company must try to achieve exactly 50% PPA and 50% Company-owned in each solicitation further complicating the lumpiness issue. For example, if the Company has a target of 150 MW and the best evaluated project is 50 MW with the second best evaluated project at 150 MW, the Company may prefer to pursue both projects, or perhaps just the 50 MW, and make up the difference in a future solicitation. However, the current requirement to award any shortfall to PURPA incentivizes the Company to over-procure the Company-owned tranche of the solicitation to prevent missing an opportunity to own and operate half of its supply portfolio. Further, with the 50% PPA and 50% Company-owned ownership structure required in each solicitation under the IRP Settlement Agreement, the Company must similarly over-award on the PPA tranche to match any over-award on the Company-owned tranche.[499]

To remedy this problem, Mr. Troyer testified that the company is recommending two changes to the solicitation process: (1) remove the requirement that leftover capacity

[499] 4 Tr 687-688.

from each solicitation be made available to QFs; and (2) allow more flexibility to acquire more or less capacity in each solicitation subject to truing up the total amount to the amount targeted in the PCA in each IRP rather than annually.[500]

In addition to the recommendations set forth above, Mr. Troyer testified that the company "proposes to generally maintain the current ownership structure of the solicitation process, with the caveat that the Company may own at least 50% of the new capacity with the remaining capacity coming from either PPAs or Company-owned resources, based on economics."[501] Noting that due to a recent PURPA settlement, the company currently owns only 20% of solar capacity, Mr. Troyer suggested that, rather than changing the ownership structure going forward, the Commission take a longer view, "with a target of maintaining the structure, beginning with the IRP Settlement Agreement [in Case No. U-20165], in each subsequent IRP."[502]

Mr. Troyer testified that the company's proposal to change the current structure, wherein Consumers can own no more than 50% of solar capacity, to one where the company will own at least 50%, is reasonable because the current ownership structure restricts the company's ability to meet its capacity acquisition targets. Mr. Troyer explained that company-owned projects are not scalable, whereas PPAs can offer a portion of capacity to the company and sell the remainder to a third party or in the MISO market.[503] Mr. Troyer also listed the company's view of the advantages of company ownership including value, cost, risk, and oversight. Mr. Troyer noted that with company ownership, Consumers can make additional investments to prolong the life of an asset,

[500] Id. at 688.
[501] Id. at 689.
[502] Id. at 690.
[503] Id. at 691.

or retire the asset early, if it makes economic sense to do so, all under the Commission's oversight. These options may not exist with PPAs unless specifically provided for in the contract.[504]

From a cost standpoint, Mr. Troyer observed that for company-owned facilities, capital costs are typically paid up front with some O&M costs over time. All costs for company projects are reviewed constantly in rate cases and other proceedings, whereas PPA costs are only reviewed at the time the Commission approves the contract, and oversight is limited to whether contract terms are met. Finally, Mr. Troyer explained that the company owns and operates facilities in the communities it serves, where it has an obligation to care for both the customers and communities, unlike third-party developers who have no such duties.

Mr. Harlow testified that Staff recognizes the company's concerns with the "lumpiness" of acquiring the precise amount of capacity in each solicitation when the projects are of varying sizes. According to him, Staff supports additional flexibility "but continues to see value in a 50/50 ownership model, as it allows for a gauge of market pricing trends and provides a reasonableness check for Company-owned assets."[505] Mr. Harlow added that the Commission supports a transparent and non-discriminatory competitive procurement process as set forth in Section 3 of the Competitive Procurement Guidelines.[506] Mr. Harlow testified that "Staff supports the Company's proposal to procure at least 50% Company-owned assets and more or less than a 50/50 split in a particular solicitation provided: 1) the Company still solicits PPAs annually to be able to continue

[504] Id. at 692.
[505] 8 Tr 3559-3560.
[506] Id. at 3560.

gauging the market and 2) the 50/50 split is reconciled in each IRP so that any shortfalls are made up in the subsequent IRP cycle."[507]

Dr. Dismukes explained that in the settlement in Consumers' first IRP, the parties agreed that new capacity would be procured in annual solicitations with 50% of capacity from PPAs and the remainder through company-owned projects, providing the company with discretion to acquire more than 50% of capacity through PPAs. Dr. Dismukes noted that while the requirement under Act 295 that limited utility ownership of renewable assets to 50% was removed under Act 342, the rationale for the restriction, namely that allowing third-parties to provide renewable energy through PPAs would foster competition, remains valid. The Attorney General therefore recommended that Consumers' request to modify the ownership structure be rejected.[508]

Mr. Dauphinais also recommended that the Commission reject Consumers' proposal, testifying that if the company believes that the current ownership structure harms customers, then there should be no ownership limits at all and all bids should be evaluated based on economics.[509]

Dr. Sherman testified that investor-owned utilities have a significant financial incentive to own all generating facilities, and that if the company's proposal were accepted, Consumers could end up owning all, or virtually all, new solar facilities. Dr. Sherman observed that in the past, the average cost of solar PPAs has been lower, even including the FCM, than company-owned projects.[510]

[507] Id. at 3560.
[508] 8 Tr 2118-2119.
[509] 8 Tr 2769.
[510] 8 Tr 3242-3243, quoting the July 18, 2019 order in Case No. U18323 p. 23, and direct testimony of Meredith A. Hadala in Case No. U-20984.

According to Dr. Sherman, she is unaware of any material differences in Commission oversight and community obligations between third-party project owners and company projects, citing conversations with EIBC member companies. She noted that in the 2019 and 2020 RFPs, none of the company-owned projects that were selected were built by Consumers; instead, third-party developers built the projects and transferred the projects to Consumers under a BTA. These same developers may also undertake projects for PPAs, thus, "[t]here is no inherent difference in the types or nature of the parties developing these projects that is dependent upon the final owner of the projects."[511]

Similarly, Dr. Sherman testified that there are no differences in regulations, permitting, or Commission oversight of BTA versus PPA projects. According to her, all projects must meet the same local permitting requirements, and while Mr. Troyer's claim that capital and O&M costs are constantly reviewed in rate cases, this is only technically true. Dr. Sherman pointed out that O&M costs for individual projects are generally reported as aggregated expenses in rate case filings.[512] Dr. Sherman added that any commitments made by a developer made to a community, no matter the ultimate owner of the project, must be upheld per the terms of the contract.[513]

Dr. Sherman characterized Mr. Troyer's claim, that since the settlement in Case No. U-20165, Consumers has added only 20% company-owned solar projects to its portfolio, as misleading, noting that the company has added a 150 MW BTA project and 150 MW in PPAs. The additional PPA capacity relates to the resolution of a long-standing

[511] 8 Tr 3243.
[512] Id. at 3243-3244.
[513] Id. at 3245.

PURPA complaint and that the related PURPA PPAs were not part of the 2018 IRP.[514] On behalf of EIBC/IEI/CGA, Dr. Sherman recommended that the Commission reject Consumers' proposal to change the ownership allocation, but allow flexibility to achieve the 50/50 split over the first five years of the PCA.[515]

As noted above, MNS takes the position that by providing the company more flexibility in the size of annual solicitations, the need to change the 50/50 ownership allocation is unnecessary.

On behalf of GLREA, witnesses Rafson and Richter also opposed the change in ownership structure. Mr. Rafson pointed to the cost difference between the Washtenaw Solar BTA project at $54.46/MWh and the cost of 2020 PPAs of $49.10, contending that adopting the company's proposal would lead to much higher costs for customers.[516]

In rebuttal, Mr. Troyer reiterated that while it is difficult to fully account for the "intrinsic value" of utility ownership, there are significant differences in terms of value, cost, risk, and oversight. Mr. Troyer testified that there are a wide variety of ownership structures, many of which involve third-party developers, even if the utility ultimately owns the project, adding that the company will continue to provide the basis for pursuing company-owned projects over PPAs in seeking approval of a company-owned project.[517]

In response to concerns that the company's proposal could result in Consumers owning 100% of new projects, Mr. Troyer pointed out that the outcome of the 2019 and 2020 RFPs would have been the same under the settlement agreement or the proposal

[514] Id. at 3246.
[515] Id.
[516] 8 Tr 3824-3825.
[517] 4 Tr 751.

in this case, because the PPAs offered were at or below the cost of company-owned projects.

Mr. Troyer reiterated that the Commission provides significant oversight of the company's capital and O&M costs, whereas a PPA supplier is not regulated and the recovery of their costs are not overseen by the Commission. Mr. Troyer added that PPA developers "use" the utility's balance sheet for financing, as discussed by Mr. Maddipati, and under that assumption, Mr. Troyer suggested that the greatest risk with respect to PPAs is the corporate structure of most developers. Mr. Troyer noted that most third-party developers are LLCs owned by a parent company. As such, in the event of a financial impact or mismanagement, the parent company is protected if the LLC is bankrupted. If that were to occur, the community in which the facility was located could be responsible for site demolition with no funding from the bankrupt LLC. Mr. Troyer urged the Commission to reject claims that there are no differences in regulatory oversight or community obligations between company-owned assets and PPA assets.[518]

The parties' briefs largely rely on the testimony and recommendations of their witnesses. Consumers maintains that its proposal should be approved to make the acquisition of company-owned resources more efficient. Consumers also insists that the other parties misconstrue the company's request, again pointing out that the results of the 2019 and 2020 solicitations would have resulted in a 50/50 split under the revised ownership structure it recommends here.

This PFD finds the company's arguments unpersuasive. As Dr. Sherman noted, Consumers' assertion that, unlike the case with PPA projects, the specific capital and

---

[518] Id. at 753-754.

O&M costs for company projects are subject to constant scrutiny, is overstated and more theoretical than reflective of actual practice where O&M costs are presented and approved as a line item and not on a project-by-project basis. Moreover, Consumers speculates that a third-party can evade duties or commitments to communities, whereas Dr. Sherman points out that those duties are defined by the contract, and she mentions local tax disputes involving company-owned projects.[519] And, the fact remains, PPAs for renewable resources have historically been more cost effective for ratepayers, as several parties point out.

That said, Staff, MNS, and this PFD recognize the difficulties and inefficiencies of attempting to tailor each solicitation to precisely meet the 50/50 ownership allocation. The PFD agrees with MNS that simply providing more flexibility going forward, by increasing the amount of MWs solicited annually, solves this issue.

4. Power Purchase Agreement Term Length

Consumers proposes to reduce the length of PPAs from a maximum of 25 years to a maximum of 15 years. Mr. Troyer testified that in addition, the company intends to solicit PPAs for 10 years, with an option to purchase the facility or extend the PPA by five year increments.[520] Mr. Troyer explained that the company is pursuing the option to purchase facilities or extend PPAs as a means to provide a more precise comparison in value between company-owned assets and PPAs.[521]

Mr. Troyer testified that Consumers commissioned an independent analysis of PPA term lengths from Wood Mackenzie (WoodMac) to research competitive

[519] 8 Tr 3244.
[520] 4 Tr 694.
[521] Id. at 694-695.

procurement and PPA strategies in both the utility and non-utility sectors.[522] He explained that the WoodMac report compared traditional utility PPA structures to those used by commercial and industrial (C&I) customers. In addition, the report compared PPA acquisition strategies between Consumers and C&I customers, and it summarized the risks, opportunities, and evaluations of the company's approach compared to C&I customers.[523] Mr. Troyer testified that the WoodMac report supported a change from a maximum PPA length of 25 years to one of 15 years. According to Mr. Troyer:

> The C&I customer segment is successfully balancing buyer flexibility with developer certainty with contract terms in the 12 to 15-year timeframe. This shorter initial period will help ensure that the Company's customers are not saddled with higher PPA prices in the later years of a PPA. Additionally, the Company intends to include the option to extend or option to purchase in future PPAs that it acquires through the competitive solicitation process to increase the value of the PPA for customers. The combination of shorter term PPA with these options is expected to result in better PPAs for our customers.[524]

Mr. Troyer summarized other aspects of the report that identified risks and opportunities for the company's consideration including: (1) the potential for negative market prices; (2) diversification of generation risk: (3) the evaluation of bundled and unbundled renewable energy credits (RECs); (4) wholesale price separation between the project and Consumers' load; and (5) the inclusion of rights-of-first-refusal as part of PPA contracts.[525]

---

[522] Exhibit A-46.
[523] 4 Tr 695-696.
[524] Id. at 696.
[525] The WoodMac report also recommended more flexibility on commercial operation dates and "laddering" procurement, wherein the company would still undertake an annual solicitation but would stagger with staggered start dates three to five years out. 4 Tr 697. These modifications, intended to increase flexibility and ensure reliability, were unopposed.

Mr. Jester testified that MNS opposes the proposal to shorten the term of PPAs from 25 to 15 years. According to him, by reducing the time a developer has to recoup project investments, Consumers' proposal will likely drive up the bid prices, lessen competition, and increase costs to customers.[526] Highlighting the comparison between C&I customers and Consumers in the WoodMac report, Mr. Jester testified:

> The fact that commercial customer PPAs often have shorter terms does not justify use of a shorter term by Consumers. The vast majority of commercial PPAs are for facilities located in restructured competitive power markets in which the owner of a facility that reaches the end of a PPA can reasonably expect to sell power at a price determined by market conditions. In contrast, the owner of a project in the Lower Peninsula of Michigan and reaching the end of a PPA would face a monopsonistic market in which the only buyers are utilities that have incentives to own facilities even if it is more costly than a PPA.[527]

Ms. Sherman similarly criticized the WoodMac report noting that the report compares utility physical PPAs to C&I PPAs, which may be physical or virtual, an inapt comparison. According to her:

> Utilities and C&I customers are vastly different in terms of planning time horizons, capital requirements, financial models, and market structures. In addition, utility PPAs and C&I PPAs are very different both in investor return on equity and risk requirements (as described above) and in the contract terms themselves. For example, utility PPAs are often bundled and include not only energy, but also, capacity, Renewable Energy Credits ("RECs") and ancillary services. In contrast, many C&I PPA contracts are for energy-only. As a result, a third-party developer is able to contract with other entities for those other attributes of the project (i.e., capacity, RECs, and ancillary services), gaining additional revenue streams.[528]

She further observed that shortening the PPA length, as Consumers proposes, would make the company an outlier compared to other utilities.[529]

---

[526] 7 Tr 2605-2606.
[527] Id. at 2606.
[528] 8 Tr 3253.
[529] 8 Tr 3269.

In rebuttal, Mr. Troyer testified that reducing the PPA term length does not necessarily increase cost, explaining that in competitive solicitations that the company has undertaken, in some cases the shorter PPA term has resulted in lower costs and in other cases, the price increased. Mr. Troyer explained that if a supplier has an optimistic view of future market prices, then a shorter term PPA may be preferable, adding that financing or debt obligations may also influence PPA term preference. However, from the company's perspective, Mr. Troyer testified that a shorter term PPA may be preferable, assuming that solar technology costs continue to decline and efficiency improves. In that instance, one short-term PPA followed by a second short-term PPA, at a lower cost, would be more economical that one long-term PPA.[530]

Mr. Troyer reiterated that there is little correlation between longer PPA terms and lower costs, pointing to Exhibit A-132, a discovery response from Mr. Jester, and Exhibit A-130, a discovery response from Dr. Sherman, wherein these witnesses acknowledged that their responses to the company's proposal were not based on any documented evidence.[531] Mr. Troyer also testified that the company's proposal does not evince any hostility to PPAs, citing the company's 2020 solicitation where Consumers decided to over-award PPA capacity due to the quality of the bids and the number of PPAs the company has entered into since the last IRP.[532]

In its brief, Consumers reiterates the testimony of its witnesses, highlighting that neither Mr. Jester nor Dr. Sherman provided documentation to show that longer PPA term lengths equate to lower costs. Consumers adds that the purpose of the WoodMac report

---

[530] 4 Tr 755.
[531] Id. at 756.
[532] Id. at 756-757.

was not to demonstrate that shorter PPA terms will benefit customers, "the report was instead commissioned to seek additional information on current and emerging trends in renewable PPAs including . . . C&I procurement activities as well as an evaluation of the Company's renewable PPA procurement strategy to increase the Company's knowledge regarding these topics and seek opportunities for improvement in preparation of the IRP filing."[533]

Although Staff did not oppose Consumers' proposal in testimony, in its initial brief, Staff stated that it found Dr. Sherman's testimony persuasive that shortening the term length of PPAs could disadvantage third-party suppliers. Accordingly, Staff advocates that Consumers provide more analysis on the contract costs of shortening PPA term length.[534]

Quoting Dr. Sherman's testimony, EIBC/IEI/CGA contend that the WoodMac report does not support Consumers' proposal to shorten PPA contract lengths, noting that the report does support the idea that longer-term PPAs are more economical on a per MWh basis.[535] And, although the WoodMac report posits that a 12-year PPA plus a 13-year PPA would be less costly than a 25-year PPA, the assumptions about technology cost decreases used in the WoodMac report are far more aggressive than those the company used in modeling solar in the IRP.[536]

This PFD agrees with EIBC/IEI/GCA that Consumers proposal to shorten the maximum PPA term length from 25 years to 15 years was not supported. Specifically, the PFD concurs that the WoodMac report, comparing Consumers' PPA acquisition practices

[533] Consumers brief, p. 366.
[534] Staff brief, p. 111.
[535] EIBC/IEI/CGA brief, pp. 72-73.
[536] Id. p. 73

to those undertaken by C&I entities was inapt given the significant differences between public utilities and commercial businesses, as Dr. Sherman pointed out. In addition, the report relies on solar cost decreases and efficiency increases that are far more optimistic than the company used elsewhere in its modeling. Consumers may, of course, solicit bids for PPAs of varying contract lengths, provided that the company continues to offer 25-year contracts.

5. Financial Compensation Mechanism

As quoted above, under MCL 460.6t(15), the Commission may approve a financial incentive for PPAs, provided that the FCM does not exceed the utility's weighted average cost of capital.

In Case No. U-20165, Consumers requested an FCM, the mechanics of which were presented in Exhibit A-52 in that case. The company's proposal in that case characterized 25% of the NPV of new PPA payments as imputed debt, and applied the then-authorized return on equity of 10% and a gross-up factor for taxes to this imputed debt amount to derive an incentive value for each year over the life of the PPA; the NPV of these compensation payments were then discounted using the authorized return on equity and levelized over the life of the PPA using company's then-current weighted average cost of capital (WACC). The company proposed that this FCM apply to all new PPAs the company entered. In approving a contested settlement agreement in that case, however, the Commission authorized an FCM as provided for in paragraph 9 of that settlement agreement:

> The parties agree that the Company shall receive, and recover in general electric rates an FCM on all new PPAs approved by the Commission on or after January 1, 2019, including PURPA contracts. The method of cost recovery shall be determined in the Company's next rate case. However,

> the Company shall not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. For PPAs subject to the FCM, the Company will be authorized to annually earn an FCM equal to the product of PPA payments in that year multiplied by the Weighted Average Cost of Capital ("WACC"), which is currently 5.88% of the Company's total capital structure at the time of PPA execution, for the entire term of the contract. The FCM shall not exceed the WACC of the Company's total capital structure multiplied by the schedule of MWh prices in Attachment B to this Settlement Agreement based on the time of PPA execution. The parties agree that the Commission has the authority to consider the existence of an FCM in determining the overall cost of capital, including the appropriate capital structure and cost of equity, as it relates to imputed debt. The parties further agree that the amount of the FCM could be reviewed in future IRP proceedings and adjusted if circumstances warrant the adjustment and the Commission may consider the FCM in rate cases when reviewing issues related to imputed debt. However, such an adjustment would not impact the FCM approved as part of any existing PPAs. The parties agree that during the competitive bidding process addressed in Paragraph 7 of this Agreement, the Company shall provide bidding parties with information necessary to calculate the price impact of the FCM on a submitted bid.[537]

Against this background, Consumers' application in the instant case seeks to increase the size of the FCM adopted in that settlement agreement and to expand the types of PPAs to which it applies. As noted above, this PFD does not recommend that the Commission approve certain elements of the company's competitive procurement strategy, of which the FCM is also a key element. As discussed below, the ALJ also does not recommend that the Commission adopt an FCM in this case, and further recommends that if the Commission decides to adopt an incentive, the savings method adopted by the Commission in Case No. U-20713 would be preferable to the company's proposal in this case.

In his overview testimony, Mr. Blumenstock described the company's proposed FCM as follows:

[537] See June 7, 2019 order in Case No. U-20165, Exhibit A, page 9, paragraph 9.

> [B]ecause the Company is proposing to continue the competitive procurement process with modifications, the Company sought to continue the FCM. The Company proposes the FCM be applied as a fair return on PPAs at an adjusted pre-tax Weighted Average Cost of Capital. A PPA incentive helps align the Company's and customer interests by removing potential bias toward utility owned assets. This alignment of interests allows customers to access potentially lower cost supply alternatives while providing a fair return. This approach is reasonable and compliance with Act 341, Section 6t.[538]

Further testimony from Mr. Troyer explained Consumers' proposal to remove the cap on the maximum PPA payment that is eligible for an FCM:

> The FCM cap is based on a $/MWh limit which does not align with the Company's current compensation structure in PPAs which include a capacity payment based on $/ZRC-day or $/ZRC-month, and an energy payment based on $/MWh. Because of this disconnect in cap and compensation structure, the Company is limited in the amount of FCM it is able to recover for PPAs. For example, if the Company only procures ZRCs and/or RECs and not the associated energy, it would be prohibited from collecting any FCM on the PPA. Similarly, the FCM cap unfairly restricts the Company's ability to recover an appropriate amount of FCM on dispatchable resources, where the energy production may be significantly reduced in order to improve the PPAs responsiveness to energy market signals.[539]

Mr. Troyer also testified regarding the company's proposal to expand the types of PPAs eligible for an FCM to include renewable energy contracts and PPAs entered into before section 6t(15) was adopted that have been subsequently amended. In discussing the company's 2019 and 2020 solicitations, Mr. Troyer testified that the FCM was included in the economic evaluation of all PPA proposals "and its inclusion in the evaluation did not affect the ranking or impact the outcome of the solicitation results in any way."[540]

Mr. Maddipati presented the company's explanation of the need for an FCM and the proposed mechanics of the company's calculation, focusing on financial impacts. He

[538] 3 Tr 111-112.
[539] 4 Tr 664-665.
[540] 4 Tr 686.

testified that “financial analysts including rating agencies will incorporate PPA obligations in their analysis since the fixed payments, similar to interest payments, reduce financial flexibility and increase the risk of default for the utility.”[541] Elaborating on the treatment of PPA obligations as imputed debt, he characterized the perceived financial burden as “unfairly shifting costs” from the PPA provider to customers and investors of the company.[542] He testified that a PPA would not be possible without associated equity capital from the utility:

> If the Company had not raised the associated equity capital, the Company’s credit would not be sufficient to support the long-term obligations imposed by a PPA. This is hardly surprising, as PPA providers leverage the creditworthiness of PPA off-takers in order to secure advantaged financing terms, and a PPA provider would not be able to raise capital on such favorable terms, if at all, without relying on the inherent creditworthiness of Consumers Energy’s – credit which is reliant on equity capital support. PPAs utilize the equity capital of the Company, and a proper compensation mechanism is essential to ensure a fair rate of return. While PPAs have the potential to add value to customers, without the associated equity capital provided by investors, the realization of these benefits would not be possible.[543]

Mr. Maddipati drew an analogy to a child obtaining a loan with a parent as co-signatory:

> [T]he child receives more favorable loan terms with little or no money down because the lender is relying upon the parent’s credit score and net worth to determine the favorable terms. Similarly, a PPA provider is able to utilize less equity and receive favorable debt terms because the lender is relying upon the utility’s creditworthiness and equity. As a result, this PPA reliance negatively impacts the Company’s ability to attract capital, and the responsibility of maintain financial and credit metrics ultimately remains with the utility.[544]

Mr. Maddipati then testified that the currently-approved FCM does not fully address the financial impact of PPAs. While contending that he is not recommending an FCM that

---

[541] 5 Tr 946.
[542] 5 Tr 946.
[543] 5 Tr 946-947.
[544] Id. at 947.

would incorporate the impacts of imputed debt on the company's balance sheet, he proposed the use of a weighted average of the cost of the company's permanent sources of capital, adjusted to a pre-tax basis, coupled with the competitive procurement process outlined by Mr. Troyer.[545] He testified that the WACC for Consumers is "the rate of return required by investors for the deployment of capital."[546] He focused only on the cost rates for debt and equity because, he testified, "PPA expenses would not generate any substantial deferred taxes for Consumers Energy, and therefore it is appropriate to use the pre-tax WACC of the Company's permanent capital structure to calculate the incentive."[547] He used the pre-tax cost of these sources of capital because "[a]ny incentive earned by the Company for entering PPAs would be subject to income tax and therefore the appropriate incentive should clearly be based on pre-tax WACC." Mr. Maddipati testified that this incentive, applied to the annual PPA payments, is consistent with the statutory cap under section 6t(15), further testifying that it would also be permissible to apply the incentive percentage to the net present value of future PPA payments each year.[548] Mr. Maddipati articulated his view that the FCM "helps align the Company's and customer interests by removing potential bias towards utility-owned assets," allowing customers "to access potentially lower cost supply alternatives while providing a fair return."[549] Mr. Maddipati presented Exhibit A-34 to illustrate the mechanics of the FCM Consumers is requesting, showing the calculation of the 8.64% cost rate based on the long-term debt, preferred stock, and common equity amounts and cost rates approved in

---

[545] Id.at 948.
[546] Id.
[547] 5 Tr 949.
[548] 5 Tr 949.
[549] 5 Tr 949.

Case No. U-20697, increased to a "pre-tax" rate assuming that the portion of the FCM attributable in this calculation to long-term debt is not taxed, while the portion of the FCM attributable to the other two elements is taxed.

Mr. Proudfoot testified that Staff does not support the company's proposed FCM and recommends that the Commission reject any FCM in this case:

> The Company has not shown clear evidence that the energy and capacity procured through the PPAs would result in a significant negative financial impact. This specific IRP not only seeks approval to recover return on and of existing assets that would no longer be used and useful, but also seeks approval to purchase large, centralized generation that would be owned by the Company and results in significant capital investment. Therefore, it is unclear why there is any need for an FCM on PPAs at this time.[550]

He recommended that the Commission not approve an incentive based on imputed debt, but continue to consider imputed debt on PPAs in the context of setting a reasonable cost of capital in a general rate case.[551] He further explained that if the Commission does approve an FCM, Staff recommends that the incentive not apply to RPS or VGP resources, or to statutorily mandated contracts such as PURPA contracts. He also explained that if the Commission does approve an FCM, it should adopt one consistent with Mr. Nichols' testimony.[552]

Mr. Nichols recommended that the Commission adopt either the current method, or alternatively, the method approved in Case No. U-20713.[553] Mr. Nichols made clear that Staff does not recommend using the pre-tax weighted average cost of permanent capital, as the company proposes, but instead, if the Commission wants to adopt a factor,

---

[550] 8 Tr 3406.
[551] 8 Tr 3406.
[552] 8 Tr 3407.
[553] 8 Tr 3637-3638.

it should use the after-tax WACC that includes deferred taxes and all components of the total capital structure, or 5.67% as approved in Case No. U-20697.[554]

Dr. Dismukes recommended that the Commission discontinue the FCM, characterizing it as "a solution in search of a problem."[555] He testified that expenses associated with PPAs are recovered through the PSCR process, which virtually guarantees full recovery of all prudently incurred expenses and allows the utility to earn a rate of return on the financing of short-term costs between their payment of PSCR expenses and recovery from ratepayers. After reviewing the company's proposal and arguments in support, he discussed and endorsed the findings made in the PFD in Case No. U-20165, which did not recommend approval of an FCM.

Dr. Dismukes presented Exhibit AG-5, a comparison of the company's historic credit ratings by Moody's, Fitch, and S&P to its annual PPA expenses as a share of total sales to customers, concluding from the data that there is no relationship between the company's credit ratings and its PPAs. He presented Exhibit AG-7, which shows that S&P considers financial obligations created by long-term PPAs to be low risk when a utility is authorized to recover the purchased power costs through separate adjustment mechanisms.[556] Dr. Dismukes concluded that the FCM to date has not had any bearing on the company's credit rating, noting that nowhere in Moody's May 2021 announcement of a credit downgrade for Consumers Energy, does Moody's "argue that increased reliance on purchase power contracts weakens the Company's financial standing, nor

[554] The Commission's December 22, 2022 order in Case No. U-20963, p. 241, determined a weighted average cost of capital of 5.62%.
[555] 7 Tr 2081.
[556] 7 Tr 2123-2124.

does the announcement argue that the implementation of the FCM has mitigated these concerns."[557]

Addressing specific elements of the company's proposed changes to the FCM, Dr. Dismukes objected to the company's proposed increase in the FCM factor to reflect a pre-tax capital cost, disagreeing with the company's assertion that it must earn the pre-tax return because this revenue would be taxed:

> The Company explicitly argues that long-term PPA agreements have similar financial characteristics as long-term debt. I do not agree that outside equity and debt investors would agree with this characterization in the case of a regulated utility with access to near-assured cost recovery of PPA expenses through the PSCR for the same reasons expressed by the ALJ in the last proceeding. However, it should be noted that long-term debt instruments are financed at a discount to equity due to debt services having priority over equity shareholders in bankruptcy proceedings. The Company's current weighted long-term debt rate, for example, is currently 3.99 percent. Importantly, interest expenses associated with long-term debt can be expensed for tax purposes unlike financial earnings; however, accounting for this tax impact would only result in an imputed pre-tax debt rate of 5.34 percent, less than the Company's current after-tax WACC of 5.88 percent and certainly less than the proposed pre-tax WACC of 8.64 percent.[558]

Dr. Dismukes concluded that Consumers had not established that the FCM has reduced costs to ratepayers.[559]

Dr. Dismukes explained his objection to removing the $/MWh cap on FCM payments, noting that the cap was part of the negotiated agreement, and contending the company's proposal "would also decouple the financial incentives it receives from the FCM with its performance since this type of proposal would allow the Company to earn returns even when resources are not being utilized to serve load."[560] He also objected to

---

[557] 7 Tr 2125; Exhibit AG-8.
[558] 7 Tr 2128.
[559] 7 Tr 2129.
[560] 7 Tr 2126.

the company's proposal to expand the PPAs eligible for an FCM, testifying that the company has an existing obligation to pursue least cost resources.[561] As an alternative recommendation, if the Commission decides not to discontinue the FCM entirely, Dr. Dismukes recommended that the Commission reject the company's proposed changes to the currently-approved FCM.[562]

Mr. Jester recommended that the Commission reject the company's proposed increase in the FCM percentage, urging the Commission to interpret "the utility's average weighted cost of capital" using "the meaning the Commission ordinarily assigned to the phrase."[563] He cited Exhibit A-4, Schedule D-1 and Exhibit A-14, Schedule D-1 from the company's most recent rate case:

> In both cases, weighted cost of capital is computed only on the total capital structure and not on the permanent capital structure. It seems apparent that the ordinary meaning of weighted average cost of capital is based on total capital structure.
>
> Similarly, in both cases the Exhibits display a column titled 'weighted cost' that is calculation of after-tax weighted cost of capital and then show the calculation of a column titled 'Pre-Tax Return.' Again, it seems apparent that the ordinary meaning of weighted average cost of capital is the after-tax return.[564]

Mr. Jester took issue with Mr. Maddipati's testimony that PPAs should be viewed as long-term debt because they reduce the utility's financial flexibility and increase risk, testifying that the utility obligation to pay a PPA counterparty "is exactly offset by revenue and there is not a material risk to the utility's debt or equity holders" due to the PSCR

[561] 7Tr 2127.
[562] 7 Tr 2129.
[563] 7 Tr 2615.
[564] 7 Tr 2615-2616.

process.[565] He also took issue with the assertion that PPAs use the company's equity capital, characterizing this as incomplete:

> Independent power producers are able to invest in generation in restructured markets without PPAs, based on expected revenue from market sales. The principal reason that a power producer in Consumers' service territory requires a PPA in order to invest is due to the monopsony that Consumers holds for acquiring power to be delivered to Consumers' customers. That monopsony is established by law and Consumers is compensated for its investments through the regulatory process.[566]

Addressing Mr. Maddipati's further claim that PPAs impact the utility's ability to attract capital, Mr. Jester testified that the company had offered no evidence to support this statement:

> If this claim is correct, the result should be that the Company's actual cost of debt and cost of equity should increase, which should then be discernable in the company's cost of capital. It would not be discernable as caused by PPAs but as lender and investor response to the Company's total circumstances. The appropriate way to deal with this claim is not to increase PPA incentive revenue but to determine the Company's cost of capital in rate cases.[567]

Mr. Jester also disputed the company's rationale for use of the pre-tax cost of only long-term debt and equity, explaining that the FCM should be considered an incentive, and not compensation for an imputed investment, and further noting that the magnitude of the incentive is statutorily capped at the WACC.

On behalf of ABATE, Mr. Walters contrasted the company's currently-authorized WACC of 5.88% to the 9.02% pre-tax average cost of permanent capital he determined based on the company's most recent rate case,[568] characterizing the corresponding 53% increase in its FCM that Consumers seeks in this case as "egregious and

---

[565] 7 Tr 2616-2617.
[566] 7 Tr 2617.
[567] 7 Tr 2618.
[568] 7 Tr 2849.

unnecessary."[569] He recommended that the Commission reject it. While not disputing that the company must have sufficient creditworthiness to enter PPAs at reasonable terms or that the company's creditworthiness is supported in part by its equity capital, he testified that Consumers has not demonstrated a need to deviate from the current FCM. While agreeing that PPAs do not generate a significant amount of deferred income taxes, he explained that deferred taxes provide a substantial amount of capital to the company and thus enhance its credit profile.[570] Noting that capital raised by the utility is fungible, he testified "deferred taxes generated by other assets can be used as a source of cash to pay for all, or a portion of the annual PPA payments."[571] Mr. Walters further explained that rating agencies consider deferred taxes in credit metrics, and testified that the company's focus only on investor-supplied capital makes its analysis incomplete.

Mr. Richter recommended that the Commission reject the company's proposed modifications to the currently-approved FCM, including the company's request to extend the FCM to PURPA contracts and its request to remove the current $/MWh cap.[572] Citing the Commission's order in Case No. U-20165 to show that the company has the burden to prove that an FCM benefits ratepayers, he concluded that the company failed to demonstrate that the modified FCM would reduce costs for ratepayers, and recommended that the Commission adopt the model from Case No. U-20713.[573]

Mr. Rafson testified that GLREA opposes the FCM "as it increases rates, decreases PPA competitiveness, departs from the previously approved FCM, and is

[569] 7 Tr 2849.
[570] 7 Tr 2851-2852.
[571] 7 Tr 2850.
[572] 8 Tr 3804-3806.
[573] 8 Tr 3805.

designed to merely increase company profits."[574] He endorsed Mr. Richter's recommendation that the Commission approve an FCM based on ratepayer savings using the structure approved in Case No. U-20713.

Energy Michigan witness Zakem recommended that the company's proposed revision to the FCM should be rejected at least in part.[575] Reviewing the current FCM and the company's proposed increase in the FCM factor, he testified that the factor should not be viewed outside the context of the settlement agreement. Mr. Zakem explained that the settlement agreement specified not only the factor, but also the dollars that the factor would be applied to, focusing specifically on the variable costs of a PPA. He testified that the variable cost payment under a PPA is a payment for goods and services delivered, not a debt:

> Consumer Energy simply wants a different method from that in the settlement, by changing only the WACC used in the settlement calculation of the FCN but not the PPA dollars that the WACC applies to, which ends up simply providing more FCM dollars. The Commission should consider both factors together, the WACC and the PPA dollars that the WACC applies to.[576]

Mr. Zakem also addressed the company's request to expand the PPAs eligible for an FCM to include RPS PPAs as well as all amended PPAs. He recommended that the Commission allow an FCM on amendments to PPAs exiting at the time section 6t(15) was adopted only after the initial term of the PPA expires. He explained that for PPAs in place before this section was adopted, the utility needed no incentive to make the decision to buy power rather than build it:

> At the end of the initial contract term, the utility may face another build or buy decision, and then if the contract is extended or extended and modified,

[574] 8 Tr 3826.
[575] 8 Tr 3179-3185.
[576] 8 Tr 3181-3182.

> the amended PPA can be eligible for a FCN, beginning with the extended term.
>
> This recommendation will also avoid trivial amendments for the purpose of triggering a FCM.[577]

Dr. Sherman supported the company's FCM, conditioned on the company agreeing to contract for at least 50% of new capacity through PPAs.[578] She agreed that there are strong incentives for a utility to build and own all of the facilities from which it obtains electricity, and considers section 6t(15) as designed to change these financial incentives. She explained the significance of these incentives:

> Although each developer has a different business model, under certain circumstances, a developer may prefer to pursue a deal using a PPA rather than a build-transfer agreement. In this situation, it would be beneficial to the developer if their interests were aligned with, rather than at odds with, the utility conducting the competitive bidding process and contracting for the resources.[579]

Although she expressed a concern that an FCM "should not be so large as to disadvantage PPA projects in comparison to Company-owned BTA projects," she declined to comment on the specific method proposed by the company.[580]

In rebuttal, regarding the contracts to which the FCM would apply, Mr. Troyer emphasized that PURPA contracts are currently eligible for an FCM, and clarified that the company is seeking to extend the FCM to RPS and VGP program contracts as well as amended PPAs. In response to criticism regarding application of the FCM to PPA amendments, Mr. Troyer stated that Consumers is willing to limit the FCM application to incremental purchases resulting from a contract amendment, including extensions of the

[577] 8 Tr 3184-3185.
[578] 8 Tr 3256-3257.
[579] 8 Tr 3257.
[580] 8 Tr 3257.

PPA term or increases in purchase volume.[581] Additionally, he testified that the FCM should apply to renewable energy PPAs and PPA amendments because such contracts limit "the Company's ability to pursue FCM-eligible PPA or utility-owned assets."[582] He further responded to criticism that the company should not be given an incentive to do something it is legally obligated to do, noting, "MCL 460.6t(15) specifically permits a utility to earn such a return." According to Mr. Troyer, "[i]t seems misleading for Mr. Dismukes to claim that a utility is obligated to follow regulatory responsibilities without acknowledging that the earnings on PPAs are expressly permitted in the statute and a tool available to the utility."[583]

Mr. Troyer disagreed that the company has not demonstrated that the FCM has produced benefits for the company's customers, reiterating that the PPAs Consumers entered into as a result of its 2019 and 2020 solicitations demonstrate that the cost of the PPAs, even with an FCM, are less than the cost of utility-owned projects.[584] He characterized this as "a direct result of its ability to earn an FCM under the Settlement Agreement."[585]

Mr. Troyer also discussed the company's rationale for lifting the FCM $/MWh cap, in response to Dr. Dismukes' recommendation that it remain in place, citing the benefits of capacity and dispatchable resources.[586] Mr. Troyer was also cross-examined on his testimony, including questions regarding how the FCM is used in evaluating solicitations,

[581] 4 Tr 738.
[582] 4 Tr 739.
[583] 4 Tr 739-740.
[584] 4 Tr 741.
[585] 4 Tr 741.
[586] 4 Tr 738-739.

the cost of PPAs relative to utility-owned projects, and his assertions regarding the incentive effect of the FCM.

In his rebuttal, Mr. Maddipati first reiterated his direct testimony that PPAs have an impact on the credit of the company, also discussing specific rate agencies and presenting several exhibits.[587] Focusing on S&P first, he testified:

> S&P has the most explicit methodology for calculating imputed debt, as the agency calculates the Net Present Value ("NPV") of the PPA payments through the life of the contract and applies a risk factor to calculate the PPA's imputed debt. S&P applies a discount rate of 7% for purposes of calculating the NPV, and while the risk factor can vary based on regulatory cost recovery, a 25% - 50% risk factor is employed when cost recovery occurs outside of a general rate case. Consumers Energy's current balance of PPA debt as reported by S&P is $546 million – this balance is not currently incorporated in the Company's authorized equity ratio.[588]

He presented Exhibit A-110 to show the impact on the company's permanent capital structure of adding the $546 million to the long-term debt balance, characterizing the impact as an approximately 160 basis point increase in the debt percentage and decrease in the equity percentage.

Next, he testified that Moody's "offers a number of methodologies to calculate the imputed debt," and quoted a 2017 Moody's explanation of its rating methodology that stated: "Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default."[589] And, Mr. Maddipati referenced Exhibit A-114, a report issued by The Brattle Group, to show that some states "have incorporated the impacts of

[587] Mr. Maddipati's testimony at 5 Tr 962-971, entitled "Rationale for A FCM, does not appear to be proper rebuttal; the ALJ recognizes that a 10-month schedule allows minimal time for parties to file motions to strike, and for purposes of this PFD, the testimony is considered.
[588] 5 Tr 963.
[589] Id. at 964.

imputed debt," he testified that the company's ability to recover PPA costs through the PSCR mechanism does not eliminate the need to consider imputed debt because "PPAs are a direct obligation of the company, not customers."[590] He presented a chart at 5 Tr 966 to illustrate that PPA payments are made before any earnings can be received by equity holders, "thus placing them in an advantageous position."[591]

Mr. Maddipati also expounded on his view that PPA providers are "unfairly" using the company's capital structure:

> When comparing the price offered by a PPA provider to that of the Company's owned generation, the comparison, absent the inclusion of this financial subsidy, is not necessarily on a level playing field. As shown [in the chart at 5 Tr 966], the PPA provider is accessing capital that has the equity of the company supporting it. Whereas the Company is subject to economic conditions, sales, and potential future general rate case revision, the PPA provider is guaranteed a payment stream from the Company.[592]

After citing testimony given in Case No. U-20165 by witnesses for the Attorney General, Staff, ABATE, and MNSC supporting the settlement agreement, including the FCM adopted in that case, Mr. Maddipati also cited Dr. Sherman's testimony at 8 Tr 3253 acknowledging limits on commercial and industrial customers' ability to sign 20-year contracts "for corporate governance reasons."[593] He testified that Consumers does not enter into long-term obligations for the same reason other C&I customers do not do so, adding that, "[u]tilizing the Company's balance sheet to enter uncompensated long-term debt-like agreements would not be a reasonable course of action for the company.[594]

---

[590] 5 Tr 965.
[591] 5 Tr 965. The "them" in this sentence appears from context to refer to PPA providers, because Mr. Maddipati asserted prior to this sentence that "the risk for a PPA provider is that of its counterparty."
[592] 5 Tr 966.
[593] 5 Tr 969.
[594] 5 Tr 696.

Mr. Maddipati testified that he did not propose an FCM based on imputed debt, in part based on the cap on the amount of PPAs and the duration of those PPAs. He reiterated that if Mr. Troyer's recommended changes to competitive procurement are not adopted, Consumers would not propose entering any new PPAs "unless the impacts of imputed debt are incorporated into the Company's capital structure."[595] Mr. Maddipati disputed that a shared savings mechanism is an appropriate incentive "as method for incorporating the credit impacts on the cost of capital." He testified that if the Commission adopts a savings mechanism, "the Commission should adjust the Company's capital structure to accommodate the imputed debt created by PPAs and then allow for an incentive based on the difference between the levelized cost of a PPA (including the imputed debt) and the cost of a Company-owned asset, similar to what was approved in Case No. U-20713." He presented an example of this mechanism in Exhibit A-111, showing annual PPA payments of $7.9 million increased to an annual cost of $10.2 million after adding $2.3 million in incremental equity cost to offset the imputed debt amount of 6 times the annual PPA payment, increasing the levelized per-MWh cost of the PPA from $45.00 per MWh to $58.04 per MWh. In this exhibit, this cost is greater than the "example A" hypothetical company-owned cost of $57.00 per MWh, generating no savings and no incentive, while this cost is less than the "example B" company-owned cost of $65.00 per MWh, thus generating savings of $6.96 per MWh and an incentive of 30% of that amount.

Mr. Maddipati addressed Mr. Proudfoot's testimony to the effect that the company had not established a significant negative financial impact from PPAs, contending that the

[595] 5 Tr 970.

company need not show a significant impact, and also contending that he had made such a demonstration. Citing Exhibit A-110, discussed above, he testified:

> While Staff argues the issue of imputed debt can be addressed in a separate proceeding, it should be noted Staff has consistently argued against the inclusion of off-balance and on-balance sheet debt items that have not previously been included in regulatory capital structure. The Company cannot proceed with its planned competitive procurement strategy without reasonable assurance that the credit impacts of PPAs will be recognized and compensated. My rebuttal testimony also provides further evidence that PPAs are currently skewing the equity capital ratio of the Company as outlined in Exhibit A-110 (SM-3).[596]

He contended that "[u]nless Staff proposes that any new PPA contract include provisions to either modify the price or cancel the contract at the Company's discretion, not evaluating all costs associated with a PPA at the time it's entered would lock customers and the Company into contracts that are potentially more expensive than alternatives."[597] Addressing Staff's recommendation that any FCM should not be applied to all contracts as Consumers requests, Mr. Maddipati contended that Staff had not offered any reasons for this recommendation, reiterating his view that PPAs create debt-like obligations "and the equity capital provided by investors supports this financing mechanism."[598] He testified that for any PPAs for which the Commission does not authorize an FCM, the imputed debt from those PPAs should be incorporated in the company's capital structure.[599]

Addressing Mr. Walters' concern with the magnitude of increase the company is seeking in its FCM, Mr. Maddipati testified this concern "lacks context" because the

[596] 5 Tr 978.
[597] 5 Tr 979.
[598] Id. at 980.
[599] Id.

company is not requesting a 53% change in its revenue requirement.[600] He testified that the incremental revenue associated with the company's most-recently-filed PPA in Case No. U-20165 would be approximately $300,000. Comparing this figure to the company's total $4 billion revenue requirement, he testified that the 53% increase "is hardly egregious."[601] Mr. Maddipati responded to Mr. Walters' testimony regarding the importance of deferred income taxes to the company's capital structure by contending that Mr. Walters fails to recognize that "deferred income taxes are used to fund the assets that generate those deferred income taxes," accusing Mr. Walters of "attempting to use the same dollar twice, once to fund the asset that generated the deferred income tax at 0% cost and the second time to pay for the PPA."[602] He further testified: "Since PPAs create no incremental deferred income taxes the impact is solely negative to the credit metrics."

Responding to Dr. Dismukes' testimony, Mr. Maddipati objected that "Dr. Dismukes does not even acknowledge that PPAs create a financial obligation for the utility. While the AG did not initially support an FCM in the Company's prior IRP, the AG's expert witness in that case explicitly noted the financial obligations created by PPAs. Dr. Dismukes has simply ignored this impact without any reason for why the rationale previously offered no longer applies."[603]

Mr. Maddipati also took issue with Mr. Jester's discussion of the ordinary meaning of the term 'weighted average cost of capital," arguing: "[t]he term WACC is the rate customers pay for the capital provided by investors (which does not include deferred

[600] Id. at 982.
[601] 5 Tr 983.
[602] 5 Tr 983.
[603] 5 Tr 989.

income taxes) – and since it's being applied to customer costs, it should be done on a pre-tax basis."[604] He also disputed that the Commission's order in the previous IRP addressed the statutory cap.[605] Mr. Maddipati acknowledged Mr. Jester's testimony that a good practice for Consumers to mitigate risk would be to include a regulatory out in its contracts, contending:

> Mr. Jester is conflating the method of cost recovery with the legal obligation incurred by the Company. . . [T]he fact that PPA costs are recovered through a PSCR mechanism does nothing to change the fact that credit and financial analysts treat PPAs similar to long-term debt when analyzing the Company. Their concern is not necessarily whether the Company will be able to recover sufficient funds through rates to pay those obligations; it is whether the money recovered through rates to pay those obligations will create greater risk that other debt holders and equity investors will not be paid for their investments if the Company's revenues experience stress.[606]

He also took issue with Mr. Jester's discussion of monopsony power, citing the existence of the MISO market. Finally, he contended that by acknowledging the potential for PPA obligations to affect the company's financial profile, Mr. Jester is "asking the Commission to approve PPAs now and then increase customer rates later to subsidize the financing of these PPAs."[607]

In response to Dr. Sherman's testimony regarding the benefits of longer-term PPAs, Mr. Maddipati testified that PPAs are able to obtain lower-cost financing with longer-term PPAs "because the PPA provider is using a great portion of the utility's balance sheet to finance the assets and shifting the risk to the utility and its customers."[608] In response to her concern regarding the potential impact of the FCM on the company's

[604] 5 Tr 994.
[605] 5 Tr 995.
[606] 5 Tr 995-996.
[607] Id. at 997.
[608] Id.

evaluation of PPA bids relative to company-owned projects, Mr. Maddipati testified that the "cost of imputed debt created by PPAs . . . should be considered by the Commission irrespective of the size of the adder."[609] Responding to Mr. Zakem, Mr. Maddipati found his testimony that the FCM approved in Case No. U-20165 should be viewed in the context of the settlement as a whole, and that the FCM percentage should also be considered relative to the base to which is applies, to be "unclear." He testified that the incentive "scales as the Company enters more PPAs and ultimately pays more PPA expense," and also characterized the incentive as "relatively modest compared to the Company's total revenue."[610] Responding to Mr. Richter's recommendation that the Commission adopt a shared savings mechanism, Mr. Maddipati referenced his recommended shared savings mechanism as illustrated in Exhibit A-111, discussed above. Responding to Mr. Rafson's testimony, he agreed that Consumers would not pursue PPAs without approval of its proposed FCM because "PPAs leverage the Company's balance sheet and entering into such PPAs without addressing the cost would not be fiscally responsible as it could raise the Company's cost of capital over the long term."[611] He testified that the company would use competitive bidding for build-transfer agreements only.

Mr. Maddipati was also cross-examined on his testimony, responding to questions regarding his views on imputed debt, and questions regarding rating agency considerations of imputed debt.

---

[609] Id. at 998.
[610] 5 Tr 998, 999.
[611] 5 Tr 1000.

The parties' briefs in this case generally follow the testimony of their witnesses. Consumers asks the Commission to approve the FCM described by Mr. Troyer and Mr. Maddipati, in conjunction with the other elements of the company's procurement strategy as discussed above.[612] The company's argument starts with the premises that the traditional regulatory model creates a bias toward utility ownership, and that PPAs generate hidden costs for utilities that should be recognized in the evaluation of alternatives. The company relies primarily on the arguments Mr. Maddipati made in his direct and rebuttal testimony to justify its proposed increase in the FCM,[613] including his specific responses to the testimony of witnesses for Staff, the Attorney General, ABATE, MNS, and GLREA.[614] Consistent with Mr. Maddipati's rebuttal testimony, Consumers states that the company would accept continuation of the current method of calculating an FCM, provided that the number of PPAs is limited to 50% and the term of each is limited, with the other modifications described by Mr. Troyer.[615] Consumers also relies on Mr. Troyer's testimony in arguing that the FCM should apply to RE PPAs as well as PPA amendments, and that the cap adopted as part of the current FCM should be lifted.[616]

Staff recommends that the Commission reject the company's proposed FCM for the reasons explained by Mr. Proudfoot, arguing that the company has not shown that any FCM is necessary.[617] Should the Commission determine to provide some incentive, Staff proposes as a preferable alternative either the method adopted in the settlement agreement in Case No. U-20165 or the method adopted in Case No. U-20713, as

[612] Consumers brief, pp. 391-403.
[613] Consumers brief, pp. 392-394.
[614] Consumers brief, pp. 394-401.
[615] Consumers brief, p. 394.
[616] Consumers brief, pp. 401-403.
[617] Staff brief, pp. 95-99.

explained by Mr. Nichols.[618] Staff argues that any incentive should not be applied to RPS, PURPA, or VGP PPAs. Staff acknowledges the company's willingness to accept continuation of the current FCM as long as all other elements of its competitive procurement process are approved, but Staff emphasizes that its preference is for the Commission to simply reject an FCM.[619]

The Attorney General relies on Dr. Dismukes' testimony in recommending termination of the current FCM.[620] She contends that not only has the company failed to provide an evaluation of the total cost to ratepayers of the changes it is seeking, it has not presented an estimate of the total cost to ratepayers of the current FCM, or attempted to quantify any benefits to ratepayers attributable to the current or proposed FCM.[621] The Attorney General takes issue with Mr. Troyer's rebuttal testimony attributing savings from PPAs the company pursued because of the FCM, characterizing the testimony as mere assertion.[622] The Attorney General takes issue with Mr. Maddipati's rebuttal testimony regarding the company's need for compensation for "imputed debt" by arguing that the statute authorizes an "incentive" rather than "compensation,"[623] that the regulatory capital structure is properly considered in rate cases,[624] and that the company overstates rating agencies' view of the risks associated with PPAs.[625] If an FCM is adopted notwithstanding her objections, the Attorney General further objects to lifting the cap included in the

[618] Staff brief, pp. 96-97.
[619] Staff brief, p. 98.
[620] Attorney General brief, pp. 80-100.
[621] Attorney General brief, p. 98.
[622] Attorney General brief, pp. 90-91.
[623] Attorney General brief, p. 92.
[624] Attorney General brief, pp. 92-93.
[625] Attorney General brief, pp. 93-98.

current FCM,[626] objects to expanding the PPAs for which the company can recover an FCM,[627] and objects to increasing the FCM above current levels.[628]

MNS argues that both the use only of the company's permanent capital and its adjustment to a pre-tax revenue violate the statutory cap on the FCM.[629] Citing the Commission's prior decisions in Case Nos. U-20350, U-20713, and U-20963 along with Mr. Jester's testimony, MNS argues that the ordinary meaning of the statutory phrase "weighted average cost of capital" is the company's WACC as determined in its rate cases, based on its total capital structure on an after-tax basis. MNS disputes the company's assertion that PPA costs should be treated as long-term debt of the utility, arguing that because the costs are recovered through the PSCR process, there is no material risk to the utility's debt or equity holders. MNS argues that if the Commission continues to authorize an FCM for Consumers, it should continue to use the method approved in the Case No. U-20165 settlement agreement.[630]

ABATE argues the Commission should reject the company's proposed changes to the FCM, characterizing the increase in the factor the company proposes to apply to its PPA costs as unnecessary and unreasonable.[631] ABATE further argues that the increase violates the statutory cap by moving from the after-tax WACC used in ratemaking to a pre-tax average cost of capital based only on the company's permanent capital structure. ABATE argues that the WACC must include deferred taxes, also disputing that deferred

[626] Attorney General brief, p. 88-89.
[627] Attorney General brief, pp. 89-90.
[628] Attorney General brief, pp. 99-100.
[629] MNS brief, pp. 140-141.
[630] MNS brief, p. 142; reply brief, p. 77.
[631] ABATE brief, pp.44-46; reply brief, pp. 22-23.

taxes as a source of financing should be ignored because PPAs themselves do not generate deferred taxes:

> Specifically, while PPAs themselves may not generate deferred taxes for the Company, Consumers receives a substantial amount of deferred taxes from other assets which generally enhance Consumers' annual cash flows, meaning they enhance the Company's credit profile, and can be used to fund annual PPA payments.[632]

ABATE cites testimony by witnesses Walters, Dismukes, Zakem, Proudfoot, and Richter in arguing that the company did not demonstrate a need to deviate from the currently-approved FCM.

GLREA argues that the Commission should discontinue the FCM for future PPAs.[633] GLREA cites the testimony of witnesses Proudfoot, Dismukes, Rafson, and Richter in support of its contention that the company has failed to demonstrate that an FCM is in the interest of ratepayers. GLREA disputes that the FCM will avoid company bias toward company-owned assets:

> When making generation resource acquisition decisions, either the Company is showing bias towards Company-owned assets in its decision making, or it isn't. The Company can't have it both ways. If the company is not allowing this potential bias to influence its decisions, there is little support for the company's request for enhancements to the FCM. If the company is making biased decisions, the company is not acting in the best interest of its customers.[634]

It further argues in its reply brief that the fact that under the current FCM, Consumers has pursued company ownership to the full extent permitted by the settlement agreement demonstrates that the FCM failed to incentivize the company to pursue PPAs that they would not otherwise pursue.[635]

---

[632] ABATE brief, p. 45-46.
[633] GLREA brief, pp. 21-23; reply brief, p. 3.
[634] GLREA brief, p. 22.
[635] GLREA reply brief, p. 3.

GLREA argues that if the Commission wishes to adopt an incentive, it should require a savings-based mechanism such as the one approved in Case No. U-20713, and should exclude PPAs entered into as part of the company's REP as well as modified or amended PPAs.[636]

The CEOs request that the Commission reject the company's proposed FCM and allow the company to file a revised IRP with a financial incentive based on savings achieved for customers, similar to the incentive approved in Case No U-20713.[637] They argue that Consumers has failed to show the current FCM has benefitted customers, or that its proposed FCM will benefit customers. The CEOs characterize as speculative the company's claim that PPAs have an adverse effect on its cost of capital.[638] The CEOs further argue that the intent of an FCM is not to compensate the company for perceived financial impacts of PPAs, but to achieve savings for customers through a PPA option. In their reply brief, the CEOs argue that the Commission's order in Case No. U-20165 approved an FCM as the product of compromise on multiple issues, while the Commission's decision in Case No. U-20713 was made after considering "exhaustive testimony and briefing" on the FCM alone.[639]

Energy Michigan states that it "does not necessarily contest Consumers' proposal to change the basis of the WACC factor from after-tax to pre-tax"[640] but cites Mr. Zakem's testimony explaining his concerns that the incentive factor would apply to the full PPA payment, even though that payment includes the variable costs of the supplier. Energy

[636] GLREA brief, p. 23.
[637] CEOs brief, pp. 47-49, reply brief, pp. 17-18.
[638] CEOs brief, p. 49, also citing cross-examination of Mr. Maddipati at 5 Tr 1069-1070.
[639] CEO reply brief, p.18.
[640] Energy Michigan brief, p. 9.

Michigan urges the Commission to consider both the percentage level and the PPA payment factor together in assessing the total effect of the FCM.[641] Energy Michigan also relies on Mr. Zakem's testimony in arguing that amended PPAs should only be eligible for an FCM after the initial term expires.[642]

EIBC/IEI/CG are generally supportive of the company's proposed FCM, provided the company's current obligation to procure at least 50% of its new capacity through PPAs is retained, as discussed above, and provided that the calculation method is transparent to bidders and not so large as to disadvantage those bidders.[643] They argue: "It would be a sad irony if an overgenerous FCM were adopted that ultimately undermined the competitiveness of proposed PPA projects."[644]

In its reply brief, Consumers reiterates the company's willingness to maintain the current FCM, "as long as it is understood . . . that the company will retain flexibility to own at least 50% of its new generation resources and to contract for shorter terms for those PPAs it does utilize."[645] Consumers further responds to Staff's view that an FCM is not needed, arguing that the IRP assumes an increase in solar above the levels in the company's last IRP, 7,800 MW by 2040, an increase of 1,450 MW above the U-20165 levels.[646] Addressing the Attorney General's and GLREA's argument that no FCM should be needed for the utility to pursue least-cost planning, the company argues that no such legal requirement exists. It argues that Commission's authority is to fix just and reasonable rates, balancing the interests of investors and the public, while rates may be

[641] Energy Michigan brief, pp. 8-10.
[642] Energy Michigan brief, pp. 10-11.
[643] EIBC/IEI/CG brief, pp. 75-76.
[644] EIBC/IEI/CG brief, p. 76.
[645] Consumers reply brief, p. 163-164
[646] See Consumers reply brief, pages 164-165.

"materially higher than is required to meet the Constitutional test, and still be regarded as reasonable."[647] The company focuses on its need for compensation:

> Since the traditional ratemaking paradigm requires the utility to forego any profit at all for segments of the business that do not include Company ownership of assets, the interests of utility investors are not properly balanced and incorporated in the making of utility rates if the utility is expected to merely serve as an uncompensated conduit between customers and other companies' profitable enterprises. Planning for current and future capacity needs, coordinating the procurement of those resources, and ensuring that sufficient electric generation capacity is available when and where it is needed are significant business undertakings that should be compensated in some respect. Again, Consumers Energy will not utilize PPAs to acquire approximately half of the expected new solar needed in this IRP if it does not have an acceptable FCM.[648]

It argues that it is also in the customers' interest to have a financially healthy utility, contending that PPAs will drive up capital costs and hamper access to equity needed to finance utility operations. Citing *Union Carbide,*[649] Consumers further responds that the parties disputing this detrimental impact fail to realize that it is the company's perception of this impact that matters:

> As long as Consumers Energy believes there is a detrimental impact caused by entering a significant number of PPAs without an adequate FCM, that will be a factor in Consumers Energy's management decision, which may result in the Company choosing more utility-owned options over PPAs than it would if there were an adequate FCM.[650]

Discussion

As quoted above, Paragraph 9 of the settlement agreement in Case No. U-20165 providing for the currently-approved FCM stated in key part: "The parties further agree that the amount of the FCM could be reviewed in future IRP proceedings and adjusted if

[647] Consumers reply brief, p. 166.
[648] Consumers reply brief, p. 166.
[649] *Union Carbide Corp. v PSC*, 431 Mich 135 (1988).
[650] Consumers reply brief, p. 167.

circumstances warrant the adjustment."[651] In its June 7, 2019 order approving the current FCM, the Commission recognized that if Consumers could not show that the FCM reduces costs for Michigan customers, it has the authority to discontinue the FCM for new contracts in Consumers' next IRP case.[652] As shown from the review of briefs above, several parties, including Staff, the Attorney General, and GLREA, recommend that the Commission discontinue the FCM as unnecessary and not shown to be in ratepayers' best interest. Consumers instead contends that it needs an FCM as compensation for the financial impacts of PPAs and that its willingness to pursue PPAs is dependent on approval of the entirety of its competitive solicitation proposal, including its proposed FCM. For the reasons discussed below, this PFD recommends that the Commission discontinue the FCM following its final order in this case, and in the alternative, should the Commission determine that an incentive is appropriate, adopt a shared savings FCM of the form adopted in Case No. U-20713.

First, this PFD finds that Consumers has failed to establish that it needs an FCM, either as "compensation" for financial impacts or as an "incentive" to pursue reasonable and prudent PPAs. Regarding its claim that it requires an FCM to offset financial impacts of PPAs because they are viewed as imputed debt by some rating agencies, the company has clearly exaggerated the magnitude of any impact. Mr. Proudfoot's testimony that the company has failed to show that procuring energy and capacity from PPAs would result in a significant negative financial impact is persuasive on this point.[653] Dr. Dismukes' finding that there is no demonstrable relationship between the company's historical PPA

[651] June 7, 2019 order in case No. U-20165, Exhibit A.
[652] June 7, 2019 order, p. 85.
[653] 8 Tr 3406.

costs and its credit ratings is also persuasive.[654] Citing Exhibit AG-8, Dr. Dismukes testified:

> The FCM was implemented in mid-2019, however, since its implementation the Company has experienced credit downgrades. In its May 2021 announcement, for example, Moody's downgraded Consumers Energy from Aa3 to A1, noting poor outcomes of the Company's last rate cases and declining financial metrics caused by the 2017 federal tax reforms and continued high leverage to support elevated capital investments. Nowhere in Moody's announcement does it argue that increased reliance on purchase power contracts weakens the Company's financial standing, nor does the announcement argue that the implementation of the FCM has mitigated these concerns.[655]

Dr. Dismukes further testified that in Exhibit AG-8, Moody's "noted that several regulatory and statutory practices in Michigan mitigate financial risks including timely cost recovery, such as that provided through the PSCR, as well as a streamlined rate case process."[656] In a similar vein, Exhibits AG-7, AG-9, AG-10, and HSC-8 support Dr. Dismukes' conclusions. In Exhibit AG-7, in explaining its "adjustment of financial measures to incorporate PPA fixed obligations . . . [achieving] greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load," S&P states: "PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates."[657] In Exhibit HSC-8, Moody's expressly states that PPAs that reduce operating and financial risk are "credit positive."[658] Both Moody's in Exhibit AG-10 and S&P in

---

[654] 7 Tr 2123.
[655] 7 Tr 2125.
[656] 7 Tr 2125.
[657] Exhibit AG-7, p. 12.
[658] Exhibit HSC-8, p. 46.

Exhibit AG-9 identify the company's planned capital expenditures as a source of financial risk.[659]

In contrast, despite Mr. Maddipati's numerous assertions, his testimony is unpersuasive that credit rating agencies do regard or reasonably should regard PPAs approved by the Commission as presenting any material risk to debt or equity holders. At the heart of the company's contention that PPAs have an adverse effect on its cost of capital is the following explanation Mr. Maddipati provided in his rebuttal testimony as he contended that recovery of PPA costs through the PSCR mechanism is irrelevant to rating agency evaluation of risk:

> [T]he fact that PPA costs are recovered through a PSCR mechanism does nothing to change the fact that credit and financial analysts treat PPAs similar to long-term debt when analyzing the Company. Their concern is not necessarily whether the Company will be able to recover sufficient funds through rates to pay those obligations; it is whether the money recovered through rates to pay those obligations will create greater risk that other debt holders and equity investors will not be paid for their investments if the Company's revenues experience stress.[660]

Consumers quotes this testimony in its brief to show "PPAs have a negative impact on the Company's credit quality despite the exhibits of a PSCR mechanism for recovering the costs."[661] This "explanation," however, lacks explanatory power. It is not reasonable to expect that a PPA approved by the Commission, for which cost recovery is provided to the dollar through Act 304 and through Act 295, will jeopardize the company's ability to use the money otherwise provided through base rates to cover its debt and equity costs. While the record shows that credit rating agencies take differing approaches to the consideration of imputed debt, as the Attorney General explained in her brief at pages

[659] Exhibit AG-9, p. 7; Exhibit AG-10, pp. 3-4.
[660] 5 Tr 995-996.
[661] Consumers brief, p.395.

94-97, there is no credible evidence that the explicit or implicit recognition of PPA obligations has had a material impact on any rating agency's perception of the riskiness of Consumers as a borrower or as an equity investment.

As part of its claim that the cost recovery mechanisms applicable to PPA costs are irrelevant, Consumers argues that, as the contracting party, the utility has ultimately responsibility to meet the PPA payment obligations.[662] The existence of this legal distinction does not further explain how PPAs have any material impact on the company's financial risk, or the cost of capital passed through to ratepayers, when both statutorily and practically, ratepayers reimburse the company for the costs of its approved PPAs. Not only are the direct PPA costs recovered through Act 304 and/or Act 295, but to the extent Consumers requires capital to pay expenses in advance of receiving revenue from ratepayers, ratepayers also fund a working capital allowance and short-term debt financing for the utility through base rates.

Further protecting the company's creditors and equity holders from risk, as Mr. Jester testified, the company's contracts as approved in Case No. U-20165 contain regulatory out clauses. Mr. Jester cited paragraph 7.4 of the company's standard offer contract, filed in Case No. U-20165 to comply with the Commission's May 26, 2021 order in that docket.[663] The same language appears in the other PPAs approved in that docket; these contracts also do not become effective until they are approved by the Commission, as provided in paragraph 2.1 of the agreements.

---

[662] Consumers brief, p. 395.
[663] 7 Tr 2617 at n 27.

While Consumers has not established that it is likely to incur any PPA-related costs in pursuit of its PCA that are not fully funded by ratepayers, it also contends that the PPA providers are wrongly "using" the company's capital structure, and that the company and its ratepayers are thus "subsidizing" the PPA providers. In part, the company's argument turns on a claim that to offset "imputed debt," it must increase the equity layer in its capital structure.[664] As discussed above, Consumers has not established a material increase in its cost of capital due to PPAs. Mr. Maddipati also analogized Consumers' role relative to the PPA providers to that of a parent cosigning a loan for a child. This analogy is unpersuasive to establish that PPA providers unfairly utilize the company's capital structure. Unlike the cosigning parent in this analogy, Consumers is not legally responsible for the debts of the PPA providers. The company's obligations are defined by contract, and presumptively confer benefits on both parties. As a better analogy, the company does not claim that its employees are unfairly taking advantage of the company's capital structure if the rely on their company salaries to obtain a mortgage or other loan: the income employees earn provides a benefit to them and their work for the company provides a benefit to the company.

The company's claim in this regard also ignores the PPA providers' contractual obligations to deliver capacity and/or energy, as well as other contractual protections available to the company. Multiple other provisions of the PPAs approved in Case No. U-20165 protect the company from paying for anything other than the performance required under the agreement. Similarly, the company has not established that an FCM is required to prevent subsidization of PPA providers. As explained above, Consumers has not

[664] Consumers brief, p. 392, also citing Maddipati, 5 Tr. 946-947.

established a material impact on its capital costs attributable to PPAs that would affect the proper evaluation of the economics of PPAs relative to a company-owned project. Nor has the company considered how to evaluate the potential impact on its cost of capital from the additional debt and equity required to fund company-owned generation.

Because Consumers has not shown that the PPAs it would enter have a direct or material adverse effect on its credit rating, cost of debt, or cost of equity, as Staff and the Attorney General argue, any incidental impact on the cost of capital will be and should be addressed in the company's rate cases.[665] As Mr. Jester explained, even if there is some impact, the rate cases are the best forum to evaluate that impact:

> Witness Maddipati makes this claim, building on his earlier argument that PPAs are reliant on utility equity capital, and offers the analogy of co-signing a loan. However, he offers no evidence that PPAs affect the ability to attract capital (Maddipati Direct, p. 5). If this claim is correct, the result should be that the Company's actual cost of debt and cost of equity should increase, which should then be discernable in the Company's cost of capital. It would not be discernable as caused by PPAs but as lender and investor response to the Company's total circumstances. The appropriate way to deal with this claim is not to increase PPA incentive revenue but to determine the Company's cost of capital in rate cases.[666]

Consumers has provided no basis to separate the potential impacts on its financing costs from additional capital investments, additional PPAs, or other elements of its total circumstances. Since Consumers may file a rate case at least annually, this ensures that the cost of capital used in setting rates reflects the most recent cost information.

Turning to Consumers' claim that it needs an incentive to overcome the bias toward company ownership inherent in the regulatory model, this PFD finds that the company has not shown that the FCM acts as such an incentive, or that ratepayers

[665] See Staff brief, p. 98; see Attorney General brief, pp. 92-93.
[666] 7 Tr 2618.

benefit. As Dr. Dismukes and Mr. Jester explained in their testimony, the company has certain obligations, including an obligation to show that the capital costs it seeks to recover in a rate case are reasonable and prudent. Dr. Dismukes testified:

> The Company is incorrect in stating that it requires financial incentives to engage in least cost planning. Signing new PPA contracts or engaging in the construction of a new generation resource that is not least cost is simply an imprudent action and inconsistent with the Company's regulatory obligations. Put another way, the Company does not need an incentive to pursue least cost resources since it has a regulatory obligation to do so.[667]

Consumers disputes that this obligation is any constraint on its choice of generation ownership over third-party contracts.[668] Consumers also cites *Union Carbide* to show that it has the legal ability to refuse to contract with third-party providers. While recognizing that the Commission has the authority to set reasonable rates, the company argues that rates may lawfully be set above the constitutional minimum, at least suggesting that the Commission would be obligated to set rates to cover the entire cost of the company's actual resource acquisition strategy. The company's position is not tenable. *Union Carbide* clearly recognizes the Commission's authority over rates, and its ability to protect ratepayers from imprudent utility decision-making. *Union Carbide* does not insulate the company's choices from review, and the company's refusal to consider PPAs should its competitive solicitation proposal be rejected in any key particular demonstrates a bias against PPAs that is without foundation on this record.

A review of the testimony in this case shows that the company did not view the FCM adopted in Case No. U-20165 as an incentive**.** As GLREA and the Attorney General argue, once the minimum PPA requirement was set at 50% in the settlement agreement,

---

[667] 7 Tr 2127.
[668] Consumers reply brief, pp. 165-168.

Consumers viewed this as a firm limit on its obligation. Mr. Troyer testified that the company responded to its settlement agreement by planning to own the full 50% permitted under the settlement agreement. For example, he testified to the difficulty the company faced achieving its target of 50% ownership for each of the 2019 and 2020 solicitations, explaining, "the Company must try to achieve exactly 50% PPA and 50% Company-owned in each solicitation[.]" [669] This makes clear that the company was not responding to the FCM as an incentive to increase its PPA supply above the 50% level.

As discussed above, the company is proposing that only 50% of its requirements going forward will be filled on an economic basis, i.e. with PPAs or BTA projects, while 50% will be filled through company-owned resources without regard to cost, reducing further the opportunity for an incentive to be effective. Consumers has made no effort to project the total cost of the FCM to ratepayers, or to realistically compare the total projected cost of its competitive solicitation proposal including the FCM, to the alternative cost of a strategy that does not limit the Commission's ability to fully evaluate the cost of company ownership relative to third-party contracts.

While this PFD recommends that the Commission decline to continue an FCM, it must be recognized that in evaluating the settlement agreement in Case No. U-20165, the Commission concluded: "The Commission is persuaded that, even when the law requires Consumers to enter into contracts with PURPA QFs, this may not happen seamlessly or without delay absent an incentive that compensates the utility for the costs of contracting with third parties for capacity through PPAs."[670] Given this conclusion, it is

[669] 4 Tr 687.
[670] June 7, 2019 order in Case No. U-20165, p. 84.

appropriate to examine the alternative FCM approaches proffered in this case. As discussed below, the company's proposed FCM exceeds the statutory cap, is excessive, and should be rejected. While several parties do not object to continuation of the current FCM, some parties advocate for the shared savings approach adopted in Case No. U-20713. This PFD recommends the latter approach as the most likely to result in savings for ratepayers.

This PDF concludes that the company's proposed FCM exceeds the statutory cap limiting the magnitude of any incentive to "the utility's weighted average cost of capital." As MNS argues, this section is properly and most-straightforwardly interpreted as limiting the amount of the incentive to the company's WACC based on its ratemaking capital structure on an after-tax basis. Indeed, in Case No. U-20713, the Commission interpreted section 6t(15) as limiting the incentive to the after-tax WACC, based on the utility's ratemaking capital structure. After acknowledging DTE Electric Company's request in that case for a financial incentive equal to the utility's after-tax WACC, determined by its ratemaking capital structure, the Commission characterized the company's request as seeking the statutory maximum:

> The Commission does not agree, however, with the company's proposal to apply the maximum incentive allowed by statute to its PPA payments. The WACC represents the maximum incentive allowable under Section 6t(15), not the prescribed incentive amount. The Commission is not convinced by the record and arguments put forth by DTE Electric that this level of incentive is appropriate in this case. The primary intent of Section 6t(15) is to incentivize electric providers to utilize PPAs that may be more cost-effective over self-build options that have the benefit of earning the company a rate of return. In this case, however, authorizing the company to add an incentive equal to the after-tax WACC of 5.46% to PPA payments could lead to higher costs for customers than BTAs or other procurement options.[671]

[671] June 9, 2021 order in Case No. U-20713, p. 23.

In explaining the savings method for determining a financial incentive, the Commission further explained:

> Finally, the total incentive must be compared to the WACC to ensure compliance with the provisions of MCL 460.6t(15). For the purposes of calculating an annual maximum allowable incentive (cap) in the instant case, the product of the 5.46% after-tax WACC multiplied by the sum of the eligible PPA payments for the year shall be the cap.[672]

In seeking to increase the incentive amount above the after-tax WACC by proposing use of a pre-tax cost of capital, Consumers ignores the Commission's prior decision and the statutory language.[673] The "pre-tax weighted average cost of capital" is a misleading term in that it confuses the source of the funding of the cost of capital with an actual cost. The cost of capital to the utility, *i.e.* "the utility's" cost of capital, is what is referred to as the after-tax cost of capital. That is what the utility is projected to actually pay.

The company's justification for using a tax multiplier, which generates the higher "pre-tax weighted average cost of capital," is its assumption that the source of funds used to pay the incentive, i.e. revenue from ratepayers not offset by tax-deductible expenses, is subject to income tax. This concern is not reflected in the statutory cap, which looks

[672] June 9, 2021 order in Case No. U-20713, p. 28.

[673] Mr. Maddipati in his rebuttal testimony at 5 Tr 994 and the company in its brief at p. 396 argue that the Commission did not address the interpretation of the statutory cap in its June 7, 2019 order in Case No. U-20165, but they do not address the Commission's June 9, 2021 order in Case No. U-20713. While the Commission did not expressly address the interpretation of section 6t(15) in Case No. U-20165, the settlement agreement itself, in paragraph 9, identifies the weighted average cost of capital as the 5.88% determined in the company's most recent rate case. The Commission order makes clear that Consumers as well as MEC/NRDC/SC identified that as the "weighted average cost of capital" or WACC. See June 7, 2019 order, pp. 42, 47. The Commission found persuasive MEC/NRDC/SC's point "that Section 6t(15) specifically authorizes the Commission to consider such an incentive and that the FCM complies with the limits of this statutory provision as it does not exceed Consumers' WACC." June 7, 2019 order, p. 85.

only to the utility's own WACC. Thus, the amount of incentive paid by ratepayers is limited to the company's actual, i.e. after-tax, WACC.

Similarly, the company's request to use only its "permanent" capital structure, including only equity and long-term debt, is inconsistent with the statutory limit to "the utility's weighted average cost of capital," because the utility's actual average cost of capital reflects the cost-free sources of capital supplied by ratepayers in the form of deferred taxes, as well as other sources of capital reflected in the ratemaking capital structure. The critical statutory words are "the utility's . . . average cost of capital." The ratemaking capital structure reflects the utility's actual WACC; the permanent capital structure by analogy represents the utility's marginal cost of capital, adding additional equity and debt, once the deferred tax balances, short-term debt funding, and other sources of capital are set, but it does not reflect the utility's weighted average cost of capital. Thus, the straightforward interpretation of MCL 460.6t(15) limits the financial incentive to the utility's WACC as reflected by its ratemaking capital structure on an after-tax basis.[674]

The company's proposal is also excessive because it has failed to establish that its proposal bears any relationship to the capital costs associated with a PPA, as discussed above, and has failed to tie the FCM to ratepayer cost savings. While Mr. Troyer testified that the PPA costs, including the FCM, were lower than the cost of

---

[674] This is consistent with Mr. Jester's testimony regarding the ordinary meaning of the term "weighted average cost of capital," and consistent with the Commission's recent rate case order in Case No. U-20963, which reported only the company's weighted average cost of capital based on its ratemaking capital structure. See December 22, 2021 order in Case No. U-20963, p. 241. While Mr. Maddipati, not an attorney, asserted that "[t]he term WACC is the rate customers pay for the capital provided by investors," the statute clearly refers to "the utility's" cost of capital. Mr. Maddipati's testimony at 5 Tr 994 is cited in Consumers brief, p. 395.

company-owned projects, he made no comparison of the costs and benefits to ratepayers. Moreover, the company's insistence that it will not pursue any PPAs unless its competitive solicitation approach is approved in its entirety, including an FCM, says nothing about the level of incentive that would actually motivate the company to pursue PPAs, recognizing the risks of underrecovery it would be courting, should it adhere to this position in practice.

Turning to the potential to continue the current FCM, as the Commission concluded regarding DTE in Case No. U-20713, in this case Consumers has not established the full after-tax WACC is necessary to counter the financial detriment posted by PPAs that it alleges: the company's testimony does not demonstrate the certainty of the negative credit impact; the rating agencies do not always use a debt equivalence method; and the company has not established its plans to use PPAs would impact its credit ratings by the rating agencies that do use a debt-equivalence method.[675] The Commission in that case also found that the incentive as proposed "would instead perversely incent the utility to select the highest cost PPA option, as this will maximize the incentive the utility receives when multiplied by a set percentage, regardless of whether this option results in savings to its customers."[676] The Commission found instead that an incentive tied to the savings achieved for customers through a PPA would be a better option.[677]

While the risk that the company will pursue high-cost PPAs is minimized in this case by its competitive procurement strategy, the Commission's order set forth a structure for an incentive at pages 27-28 of that order that aligns the company's interests in

[675] June 9, 2021 order in Case No. U-20713, p. 24.
[676] June 9, 2021 order in Case No. U-20713, p. 24.
[677] June 9, 2021 order in Case No. U-20713, p.25.

attaining reasonable-cost resources and obtaining additional income with the ratepayer interests in reasonable-cost resources. The Commission further found that this structure "provides the right incentive to the company and aligns with the Commission's goals of exploring and incorporating performance-based and savings-based incentives."[678] With this method, no $/MWh cap is necessary. The incentive remains capped by the utility's WACC as discussed above.

Although Consumers also proposed a version of a shared-savings mechanism that Mr. Maddipati explained in his rebuttal testimony, that savings method goes beyond shared savings to require the Commission to provide unjustified compensation for "imputed debt" before a cost comparison of alternatives can be made. The "savings" method Mr. Maddipati proposed in Exhibit A-111 first inflates the cost of the PPAs by almost 30% from $45 per MWh to $58.04 per MWh to reflect his estimate of imputed debt costs, before comparison to the cost of a utility-owned project.[679] In order to accept a shared-savings mechanism, Consumers asserts that it will require the Commission to commit to awarding the company this 30% compensation for "imputed debt" through a rate case, in addition to awarding the shared savings of 30% of the remaining difference between the PPA cost and the company ownership cost as an FCM. As discussed above, the company has shown no such significant impact on its financing costs as a result of entering into PPAs, and has made no comparison of the potential cost to ratepayers of a 100% company ownership strategy, which would require the company to

[678] June 9, 2021 order in Case No. U-20713, p. 28.
[679] Exhibit A-111, lines 11, 19, and 20.

significantly increase its long-term debt and equity financing. This PFD thus concludes that the Commission should reject this alternative version of a savings-based incentive.

Should the Commission determine to adopt an FCM, it also needs to determine what PPAs will be eligible for the FCM. This PFD finds Staff's recommendations to exclude PURPA contracts, contracts for RPS compliance, and amendments to existing contracts to be persuasive. In recognition of the Commission's order in Case No. U-20713, which adopted an FCM for VGP PPAs, this PFD recommends that the question of the applicability of an FCM for those contracts be deferred to the company's next VGP case.

I. Public Utility Regulatory Policies Act Issues

Mr. Troyer testified regarding the PURPA avoided cost construct approved in the company's previous IRP case, explaining that under the current construct, the Standard Offer Tariff and Standard Offer contact are available to QFs up to 2 MW in size. In addition, per the settlement agreement, the full avoided cost rate offered will be equal to the highest priced proposal that received a contract in the competitive solicitation and the contract length will be the same as offered in the competitive solicitation."[680] Mr. Troyer explained that Consumers offers both full and reduced avoided cost rates, with the reduced rate based either on the PRA price (adjusted annually) or on various prices based on forecasts of locational marginal price (LMP). Mr. Troyer described the current avoided cost construct as follows:

> 1. Any QF up to the Company's must buy obligation threshold can participate in the Company's competitive solicitations, regardless of the technology specified, and receive the rate included in their proposal, if selected;

[680] 4 Tr 667.

2. Any remaining capacity solicited but not filled through each solicitation is made available to QFs on a first-come, first-served basis at the full avoided cost rates based on that solicitation;

3. Any QF with an existing PPA as of January 1, 2019 with an expiring full avoided cost PURPA PPA for energy and capacity is eligible to receive the most recently Commission-approved full avoided cost rate for a new PPA; and

4. QFs up to 150 kW that request the Standard Offer Contract will receive the most recently Commission-approved full avoided cost rates.[681]

Mr. Troyer testified that Consumers is requesting several changes to the review and implementation of PURPA avoided costs including: (1) Consumers requests that the Commission confirm that the review of the company's avoided cost construct is met through IRP filings every three years;[682] (2) Consistent with FERC Orders 872, and 872-A,[683] Consumers proposes to remove two options for full avoided cost rates, namely the option for eligible QFs up to 150kW that request full avoided cost rates to receive the most recent Commission-approved full avoided cost rates and the option to make available to QFs, on a first-come-first-served basis, any unfilled capacity from an annual solicitation;[684] (3) consistent with PURPA regulations, the company proposes to reduce the size of the Standard Offer PPA from 2 MW to 100 kW; and (4) Consumers proposes to update the basis for capacity compensation consistent with the anticipated MISO seasonal construct.

Staff witness Hadala testified that Staff supports Consumers' request to meet its obligations for PURPA review through the IRP process, assuming that the company continues to file IRPs every three years. Staff also supports the company's proposal to

---

681 Id. at 668.
682 4 Tr 669.
683 July 16, 2020 Order, 172 FERC ¶ 61,041and November 19, 2020 Order. 173 FERC ¶ 61,158.
684 4 Tr 670-671.

remove QFs from eligibility for unfilled capacity from the annual solicitations, and it agreed with the company's request that as long as Consumers implements a competitive solicitation process, the company has no capacity need. And, Staff agrees with Consumers' request to remove the reduced avoided capacity rate from the standard offer tariff.

However, Staff recommends QFs less than or equal to $100kW_{ac}$ receive full avoided cost rates as updated in annual solicitations. Ms. Hadala noted that FERC Order 872 provides that QFs with capacity of 100kW or less are entitled to standard offer rates, whether or not they compete in a competitive solicitation.[685] Ms. Hadala testified that currently, QFs of 150kW or less are able to participate in either the company's DG program or in the self-generation program. Staff's recommendation would give customers with projects of 100kW or less a third option, without requiring that they negotiate a contract with Consumers.[686]

Ms. Hadala testified that Staff recommends that Consumers extend full avoided cost eligibility "to all QFs with existing contracts that include payments for capacity at a rate other than the MISO PRA. If a QF has an existing contract with capacity payments that is expiring, the QF should have the option to renew its existing contract at the current full avoided cost rate, based on the most recent results from a competitive solicitation, and continue to receive capacity payments from CE."[687] Ms. Hadala also explained that, contrary to the company's proposal, Staff recommends that Consumers produce a standard offer, energy-only contract for QFs between 100 kW and 5 MW, noting that this

---

[685] 8 Tr 3538-3540.
[686] Id. at 3541.
[687] Id. at 3542.

is consistent with the company's reduced obligation to purchase. According to Ms. Hadala:

> Staff also recommends that CE offer an energy payment option for the first five years of the contract based on a schedule of forecasted LMP rates. The following years of the contract will have energy payments based on actual LMP rates. This methodology differs from current practices. Currently, CE has an energy payment option for a 10-year contract with years 1-5 based on scheduled energy rates, and years 6-10 equal to the year six LMP forecast. Staff's recommendation for providing a forecasted energy payment for five years and then basing the payment on actual LMP prices is intended to strike a balance between a QF's need for certainty and the risk that the forecasted LMP rates will differ from actual LMP prices.[688]

Ms. Hadala explained that because Consumers will acquire all of its capacity through competitive solicitations, providing a standard energy-only contract will streamline the contracting process for both the company and QFs. Finally, Ms. Hadala testified that Staff recommends that Consumers develop a process for acquiring capacity from QFs with existing energy-only contracts before issuing a competitive solicitation. According to Ms. Hadala, "QFs in energy-only contracts would have the option to sell their capacity to CE. Once these QFs responded with their choice of whether to accept or not accept the capacity purchase offer from CE, the Company would then issue the competitive solicitation with the reduced capacity need."[689]

Mr. Kenworthy testified that projects below 150 kW are likely BTM projects, and it is not reasonable to expect these projects to compete with 2 to 20 MW wholesale projects in a competitive solicitation. Mr. Kenworthy added that PURPA-specific issues should be addressed in PURPA implementation dockets, and not as part of the IRP.[690] On behalf of GLREA, Mr. Richter likewise testified that while an IRP proceeding may be the

[688] Id. at 3543-3544.
[689] Id. at 3545.
[690] 7 Tr 2333.

appropriate venue for addressing capacity need, capacity price, and energy price, it is not the appropriate forum for addressing Consumers other proposed changes to the PURPA construct.[691]

Dr. Sherman quoted the Commission's January 21, 2021 order in Case No. U-20905 *et al*. p. 26, which stated that the Commission agreed with the Staff that the standard offer cap should be set at 5 MW if the FERC reduces the obligation to purchase, and if a utility proposes to set the standard offer at less than 5 MW, it should justify its decision.[692] Noting that Consumers has received authorization from the FERC to terminate its obligation to purchase from QFs above 5 MW, Dr. Sherman observed that not only has Consumers decided not to set its standard offer at 5 MW, but the company proposes to reduce the standard offer from 2 MW to 100 kW. Dr. Sherman testified that although Mr. Troyer presents some reasons for the change, namely that it is consistent with FERC regulations, requests for standard offer PPAs come from large, more sophisticated developers, and the FERC order 2222 allows participation in the wholesale market for DERs greater than 100 kW, these reasons should be rejected. Dr. Sherman points out that the size or sophistication of most developers requesting a standard offer is irrelevant, and while it will be possible for resources 100 kW and larger to participate in MISO, that is not expected to be the case for several years.[693]

In rebuttal, Mr. Troyer observed that he provided support for reducing the standard offer to 100 kW, as Dr. Sherman acknowledged. Mr. Troyer added that "[u]nder the PURPA Standard Offer Contract, as litigated in Case No. U-18090 and most recently

---

[691] 8 Tr 3803.
[692] 8 Tr 3237.
[693] 8 Tr 3238-3239.

approved in Case No. U-20165, there is a provision requiring the Company to pay for capacity based on the methodology at the time of contract execution, not based on the actual ZRCs delivered from MISO. This provision protects suppliers at the detriment of the Company's customers. Expanding the size of the standard offer would further exacerbate this issue."[694] However, he agreed with Staff that a standard offer, energy only contract for QFs of 5 MW or less was reasonable, and that Staff's proposal for establishing the energy rate was also reasonable.

Mr. Troyer disagreed with Ms. Hadala that the company should offer capacity contracts to QFs with existing energy-only contracts ahead of any competitive solicitation. Mr. Troyer testified that Ms. Hadala provided no details on how the company would do this or what safeguards could be put in place to avoid executing above-market PPAs. According to Mr. Troyer, "Ms. Hadala's proposal incentivizes QFs to take energy only contracts shortly before the Company's annual solicitations with the intent of switching to full avoided contracts. Not only would there be negative customer cost implications to Mr. [sic] Hadala's approach, as discussed above, but it would also be extremely administrative burdensome to the Company to potentially fill an entire solicitation with capacity from QFs 5 MW and below should the QFs request all available capacity sought in the solicitation." [695]

The PFD agrees with Staff and EIBC/IEI/CGA that, although the company is endeavoring to simplify and standardize all of its PUPPA contracts, the Commission should direct the company to develop an energy-only standard offer PPA for QFs at or

[694] 4 Tr 742.
[695] 4 Tr 749-750.

below 5 MW. The Commission found 5 MW to be reasonable in Case No. U-20905, and the company's justifications for reducing the standard offer from 2 MW to 100 kW is not persuasive. As Dr. Sherman pointed out, the purported sophistication of QF developers is irrelevant, and the prospect for DERs of 100 kW or less to participate in the MISO market may be years away.

However, the PFD agrees with Consumers' concern that first offering capacity contracts to QFs with existing energy-only contracts, using capacity prices from the company's previous competitive solicitation, could lead to inflated PPA costs, especially in light of projections that solar technology costs will continue to decrease. While this recommendation may merit further consideration, it should be addressed in a PURPA-specific proceeding. Finally, the PFD agrees with Mr. Kenworthy and Mr. Richter that although determining capacity need for purposes of PURPA may be appropriate in an IRP, more specific issues related to the company's PURPA construct are better addressed in more focused proceedings that are not time-constrained like the IRP.

J. Other Issues

1. Community Solar

Several parties, including GLREA, UCC, and Grand Rapids, advocated that Consumers include more consideration of community solar in its IRP. Mr. Rafson testified that since the settlement agreement was approved in Consumers' previous IRP, the company has had ample time to evaluate community solar as part of DG. Mr. Rafson testified that community solar provides benefits to both the utility and its customers including grid resiliency, lowered EC burden, and wealth building for customers. Mr. Rafson acknowledged Consumers' community solar efforts in its VGP program (e.g., Solar Gardens and Sunrise Pilot) but he criticized these programs for failing to include third-party ownership of community solar resources.[696]

Also referencing the EC burden for low-income customers, Ms. Waske Sutter urged Consumers to expand its community solar offerings.[697] Likewise, on behalf of the CEOs Dr. Krieger and Dr. Lukanov discussed the role of community solar in increasing energy affordability for low-income households.[698]

On behalf of the UCC, Mr. Cira-Reyes testified that although Consumers is increasing the amount of renewable energy in its IRP, the company does not go far enough, especially concerning community solar. Mr. Cira-Reyes discussed the benefits of community solar, especially for low-income communities and communities of color, including capacity and distribution reliability benefits, financial benefits, and environmental and health benefits.[699]

The PFD finds that although the issues surrounding community solar raised here have merit, and are particularly important for low-income customers, a forum for addressing the specifics of community solar initiatives is available in Consumers' VGP program filings. Thus, recommendations for improving or expanding these programs should be addressed as part of the VGP dockets.

2. Distributed Generation Pilot

In addition to recommendations concerning modeling of DG in Aurora, Mr. Kenworthy and Ms. Hotaling presented a proposal for two DG resource programs (DGRs) that would provide a financial incentive to customers, including low-income customers, to

[696] 8 Tr 3829-3835.
[697] 7 Tr 2358.
[698] 7 Tr 2366, 2374, 2389. 2434, 2448
[699] 7 Tr 2509, 2512-2517; 2539-

install rooftop solar. Mr. Kenworthy stated that the results of Ms. Hotaling's analysis showed that the addition of these DGR programs would replace utility-scale resource additions and would be more cost-effective than Consumers' PCA.[700] The CEOs contend that their modeling was sufficient for the Commission to direct Consumers to undertake a $10 million pilot low-income DGR pilot program. The UCC supported this proposal if the upfront cost of installing the technology were provided as a grant.[701]

In response, Consumers contends that, in general, the CEOs' modeling of DG was flawed because it failed to consider any costs, beyond an incentive, associated with customer-owned solar. Consumers states that it supports low-income access to solar energy, and it points to its Sunrise pilot program that provides access to community solar for income qualified customers.

The CEOs presented their DG modeling and the proposed low-income DGR pilot in their direct testimony, and the company and other parties had only three weeks to respond to the proposal. Unfortunately, given the mandated period for processing an IRP under Section 6t, there is simply not sufficient time available to address new and potentially complex proposals. The PFD therefore recommends that a low-income DGR pilot program be addressed as part of Consumers' VGP docket.

3. Voluntary Green Pricing

Mr. Rafson described the VGP program, noting that large industrial customers contracting for green energy and capacity require other customers to assume additional

---

[700] 7 Tr 2327-2332.
[701] 7 Tr 2359.

costs. Like the issues raised with respect to community solar, alleged VGP cost shifting should be addressed as part of a VGP case.

4. Site Redevelopment

Ms. Waske Sutter urges the Commission to require additional details on plans for site redevelopment at Karn and Campbell, and direct Consumers to remove coal and remediate the sites to allow for redevelopment in the future.[702] In response, Mr. Kapala testified that the company has been working with community stakeholders on site decommissioning and redevelopment plans.[703]

Like many of the other proposals addressed above, this PFD finds that issues concerning site redevelopment should be addressed in other proceedings.

5. Must-run Designation

CEO witness Daniels noted that although Consumers did not use the "must-run" designation for all of its modeling runs, in the company's next IRP, the company should turn off the must-run constraint in all scenarios and sensitivity analyses. Mr. Daniels testified that the must-run constraint forces the model to run all coal units at some minimum capacity despite the economics of doing so. Mr. Daniels explained that this is contrary to the purpose of an IRP, which is to select a portfolio of resources that most cost-effectively meets capacity and energy needs.[704]

In response, Ms. Munie testified that this recommendation no longer has any relevance because the company intends to close its coal units within a year of its next IRP. In addition, Ms. Munie explained that the Commission has repeatedly rejected

[702] 7 Tr 2353.
[703] 7 Tr 1808.
[704] 7 Tr 2293, 2295-2298.

recommendations to model coal units as other than must-run. Ms. Munie added that it would be inappropriate for the Commission to rule on the must-run designation for all utilities as part of this proceeding.[705]

This PFD agrees with Consumers that the issue of using the must-run designation for thermal coal units may not be relevant in Consumers' future IRPs. And, while the IRP may not be the appropriate proceeding to address this issue, it does appear that the Commission is considering the costs associated with bidding units into the market as must-run as part of power supply cost recovery reconciliation proceedings.

6. Change to the Calculation of Local Clearing Requirement

For Energy Michigan, Mr. Zakem testified that MISO's calculation of LCR is in error, and, if corrected, CIL for Zone 7 would increase by 527 MW at no cost and considerable customer savings. Mr. Zakem recommended that the Commission petition the FERC to correct MISO's calculation of LCR for Zone 7.[706]

The PFD recommends that the Commission consider Energy Michigan's recommendation outside the IRP.

7. Wolverine Power Supply Contract

After providing an overview of the Ownership and Operating Agreement (Agreement) between Consumers and WPSC, Mr. King testified that the terms of the Agreement provide for rights and obligations and between the parties "including, but not limited to, matters involving payment, cooperation, and consultation related to the operations and maintenance of Campbell 3, Campbell 3 capital improvements, and

[705] 7 Tr 1945-1946.
[706] 8 Tr 3188-3190.

retirement."[707] According to Mr. King, Article 7 of the Agreement provides for payments by WPSC for its share of capital, O&M, insurance, liability, certain taxes, and retirement costs, among other items.[708] Referencing Article 20.2 of the Agreement, Mr. King testified that decommissioning costs have been included in WPSC's monthly payments since the beginning of the contract, however, Consumers was unable to identify the amount of decommissioning costs the company has already collected from WPSC, nor could the company detail the retirement and decommissioning costs yet to be collected.[709] Given the absence of information on funds WPSC has already provided for retirement and decommissioning of Campbell 3, Mr. King urges the Commission to find that Consumers should be responsible for any additional retirement costs.[710]

In addition to WPSC's concerns about retirement and decommissioning costs, Mr. King pointed out that, although Articles 9.1 and 18 of the Agreement require consultation and cooperation between the parties with respect to all activities related to the operation of Campbell 3, Consumers failed to consult with WPSC on its decision to accelerate the unit's retirement. According to Mr. King, WPSC was only informed about the retirement approximately 30 minutes before Consumers made a public announcement.[711]

In rebuttal, Mr. Troyer explained that Consumers invoices WPSC its share of costs and expenses associated with the operation of Campbell 3. Mr. Troyer testified that a review of these invoices indicates that although WPSC has been billed for the cost of removal of specific equipment, the company does not consider these costs to be

---

[707] 7 Tr 2265; Exhibit WPSC-1.
[708] Id.
[709] Id. at 2269; Exhibit WPSC-2.
[710] 7 Tr 2269-2270.
[711] 7 Tr 2266-2267.

retirement or decommissioning costs.[712] Mr. Troyer dismissed Mr. King's concern about previously-paid decommissioning expenses, explaining that no decommissioning costs have been collected and therefore there is no accounting of these costs. Mr. Troyer testified that Mr. King misinterpreted the company's discovery response in Exhibit WPSC-2, explaining that the response refers to costs collected from customers (not joint owners) and placed in reserve for decommissioning.[713] Finally, Mr. Troyer testified that "Section 7.5 of the agreement, provided as Exhibit WPSC-1, unambiguously gives Consumers Energy the sole discretion to make retirement decisions of the facility."[714]

In its brief, WPSC references Consumers' failure to consult or collaborate on the decision to retire Campbell 3 in 2025, contending that Consumers breached the Agreement, but it does not address Mr. Troyer's rebuttal. In its reply brief, Consumers contends that any dispute over an alleged breach of contract must be addressed through arbitration, as set forth in Article 18 of the Agreement. Therefore, according to Consumers, WPSC's issues are not properly raised here.

The PFD agrees with Consumers and finds that WPSC's claims concerning Consumers' compliance with the Agreement should be addressed as provided in Article 18 of the Agreement.

VI.

CONCLUSION

The ALJ recommends that the Commission adopt the following findings of fact and conclusions of law:

[712] 4 Tr 728.
[713] Id. at 728-729.
[714] Id. at 729.

(1) In Consumers' next IRP, the company should use the results of its most recent competitive solicitation to establish cost assumptions for renewables.

(2) The Commission should approve the company's request to retire Karn 3 and 4 and Campbell 1 and 2 in 2023 and 2025 respectively.

(3) The Commission should require Consumers to provide additional analysis of Campbell 3 retirement in 2025 consistent with the discussion above.

(4) The Commission should find Consumers 2021 RFP deficient.

(5) The Commission should approve the company's request for costs associated with the purchase of the Covert Plant.

(6) The Commission should deny Consumers request for cost approval for the purchase of the CMS plants. If the Commission finds that the purchase of the CMS plants is reasonable, it should nevertheless deny cost recovery for the acquisition premium included in the purchase price.

(7) The Commission should direct Consumers to appropriately evaluate and model transmission alternatives in the company's next IRP.

(8) The Commission should approve the company's level of EWR included in this case, but it should defer approval of all EWR costs to EWR plan and reconciliation proceedings.

(9) The Commission should approve Consumers' DR level and capital costs associated with DR for the first three years of the IRP. DR O&M and FIM approvals should be deferred to a rate case or DR reconciliation proceeding.

(10) The Commission should approve the company's CVR capital costs, and it should direct the company to undertake additional analyses of the cost-effectiveness of CVR.

(11) The Commission should direct Consumers to convene a stakeholder group to address the details of the company's proposed battery storage program for 2024-2027.

(12) The Commission should find Consumers projected EV load reasonable for purposes of this IRP. The Commission should direct the company to update its projections of EV load in the next IRP.

(13) The Commission should defer consideration of the company's request for accounting approvals related to cost recovery for the retiring units to a special-purpose proceeding.

(14) The Commission should approve the company's request for regulatory asset treatment for decommissioning and ash disposal costs as discussed in this PFD.

(15) The Commission should direct the company to increase the size of its solar solicitations from 500 MW to 750 MW annually.

(16) The Commission should maintain the current 50/50 ownership split between company-owned projects and PPAs.

(17) The Commission should deny the company's request to reduce the maximum length of PPA terms from 25 years to 15 years.

(18) The Commission should deny an FCM for PPAs going forward.

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

Sally L. Wallace

Digitally signed by: Sally L. Wallace
DN: CN = Sally L. Wallace email = wallaces2@michigan.gov C = US
O = MOAHR OU = MOAHR - PSC
Date: 2022.03.07 12:11:09 -05'00'

Sally L. Wallace
Administrative Law Judge

Issued and Served:
March 7, 2022