



A CMS Energy Company

December 21, 2018

Ms. Kavita Kale  
Executive Secretary  
Michigan Public Service Commission  
7109 West Saginaw Highway  
Post Office Box 30221  
Lansing, MI 48909

General Offices:  
One Energy Plaza  
Jackson, MI 49201  
Tel: (517) 788-0550  
Fax: (517) 768-3644  
\*Washington Office:  
1730 Rhode Island Ave. N.W.  
Suite 1007  
Washington, DC 20036  
Tel: (202) 778-3340  
Fax: (202) 778-3355  
Writer's Direct Dial Number: (517) 788-1846  
Writer's E-mail Address: robert.beach@cmsenergy.com

LEGAL DEPARTMENT  
CATHERINE M REYNOLDS  
Senior Vice President  
and General Counsel  
Ashley L Bancroft  
Robert W Beach  
Ian F. Burgess  
Don A D'Amato  
Robert A. Farr  
Gary A Gensch, Jr.  
Emerson J. Hilton  
Gary L Kelterborn  
Chantez P Knowles  
Mary Jo Lawrie  
Jason M Milstone  
Rhonda M Morris  
Deborah A Moss\*  
Michael C. Rampe  
Scott J Sinkwitz  
Adam C Smith  
Theresa A G Staley  
Janae M Thayer  
Anne M Uitvlugt  
Aaron L Vorce  
Attorney  
MELISSA M GLEESPEN  
Vice President, Corporate  
Secretary and Chief  
Compliance Officer  
SHAUN M JOHNSON  
Vice President and Deputy  
General Counsel  
Bret A Totoraitis  
Kelly M Hall  
Eric V Luoma  
Assistant General Counsel

**RE: Case No. U-20165 – In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t and for other relief.**

Dear Ms. Kale:

Enclosed for electronic filing in the above-captioned case is the **Initial Brief of Consumers Energy Company**. This is a paperless filing and is therefore being filed only in a PDF format. I have enclosed a Proof of Service showing electronic service upon the parties.

Sincerely,

Robert W. Beach

cc: Hon. Sharon L. Feldman, Administrative Law Judge  
Parties per Attachment 1 to Proof of Service

STATE OF MICHIGAN

BEFORE 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 and for other relief. )  
\_\_\_\_\_ )

Case No. U-20165

**INITIAL BRIEF OF CONSUMERS ENERGY COMPANY**

December 21, 2018

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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Case No. U-20165

**INITIAL BRIEF OF CONSUMERS ENERGY COMPANY**

**I. INTRODUCTION AND OVERVIEW**

This case represents the first Integrated Resource Plan (“IRP”) filed in the state of Michigan pursuant to MCL 460.6t of Public Act 341 of 2016 (“Act 341”). Consumers Energy Company (“Consumers Energy” or the “Company”) has used this historic opportunity to reshape Michigan’s energy future and redefine the Company’s role in that future. The Company’s IRP presents a comprehensive and robust assessment of the Company’s capacity resource portfolio in light of capacity needs, regulatory and environmental compliance, and the planning objectives set forth by the Michigan Public Service Commission (“MPSC” or the “Commission”). In performing this assessment, the Company developed a Proposed Course of Action (“PCA”) which will provide customers with clean, affordable, and reliable electricity and represents the best plan for Michigan.

The Company’s PCA presents a fundamental shift in the resources which make up the Company’s capacity resource portfolio and also proposes to dramatically change the way the Company procures capacity moving forward. The PCA ensures compliance with the Company’s Clean Energy Goals – a reduction in carbon emissions by 80% and the elimination of coal-fired generation by 2040 – and also proposes to predominately rely on new solar resource additions to meet the Company’s future capacity needs. Furthermore, to capture declining resource costs and

better align new capacity additions with future capacity needs, the Company is proposing to use a competitive bidding process to address all future capacity needs.

The Commission should approve the Company's PCA in its entirety, because the PCA represents the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. As part of its approval of the PCA, the Company specifically requests the Commission to make the following determinations:

- (i) Approve as reasonable and prudent for cost recovery purposes the Company's proposed Energy Waste Reduction ("EWR"), Demand Response ("DR"), and Conservation Voltage Reduction ("CVR") costs which will be commenced by the Company within three years following the Commission's approval of the Company's IRP;
- (ii) Approve the Company's proposal to recover the unrecovered book balance of D.E. Karn ("Karn") Units 1 and 2, including decommissioning costs, and proposed regulatory accounting treatment through 2031;
- (iii) Approve the Company's proposed competitive-bid methodology for determining avoided costs rates and for determining and addressing the Company's capacity position pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA");
- (iv) Approve the utilization of a five-year period for the purpose of determining the Company's capacity position and related obligations pursuant to PURPA and find that the Company has no PURPA capacity need so long as the Company is implementing the PCA, as approved by the Commission;
- (v) Approve the utilization of a five-year period for the purpose of determining the Company's capacity position and related obligations pursuant to PURPA and find that the Company has no PURPA capacity need so long as the Company is implementing the PCA, as approved by the Commission;
- (vi) Approve the Company's Financial Compensation Mechanism ("FCM") for any new Power Purchase Agreements ("PPAs") entered by the Company; and
- (vii) Grant the Company such other relief as set forth in this Initial Brief and the Company's record evidence.

The following provides a procedural overview of this case and an executive summary of the Company's IRP and PCA.

**A. Procedural Overview**

MCL 460.6t of Act 341 established an IRP process and framework for electric utilities whose rates are regulated by the Commission. 6 TR 224. MCL 460.6t requires electric utilities to include specific components in an IRP filing, and provides that the Commission shall approve a proposed IRP if the Commission determines that the IRP represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make such a determination, the Commission must consider whether the proposed IRP appropriately balances 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.” MCL 460.6(t)(8)(a).

To enable IRP filings, MCL 460.6t required the Commission to: (i) establish modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing an IRP and (ii) establish filing requirements, including application forms and instructions, and filing deadlines for an IRP filed by a utility regulated by the Commission. See MCL 460.6t(1)(f) and (3). In compliance with the above statutory provisions, the Commission set forth all required IRP modeling scenarios and assumptions, requirements, instructions, and guidelines for utilities filing IRPs by issuing an Order dated November 21, 2017 in Case No. U-18418 approving “Michigan Integrated Resource Planning Parameters” (“MIRPP”). The Commission also issued an Order on December 20, 2017 in Case Nos. U-15896 *et al.*, which approved “Integrated Resource Plan Filing Requirements.” These documents set forth all required IRP modeling scenarios and assumptions, requirements, instructions, and guidelines for utilities seeking relief pursuant to MCL 460.6t.

As directed by the Commission in its December 20, 2017 Order in Case Nos. U-15896 *et al.*, Consumers Energy filed the first ever IRP under MCL 460.6t on June 15, 2018. A prehearing conference was subsequently held on July 16, 2018 before Administrative Law Judge (“ALJ”) Sharon L. Feldman. The Commission Staff (“Staff”); Michigan Environmental Council, the Sierra Club and the Natural Resources Defense Council (collectively “MEC”); the Association of Businesses Advocating Tariff Equity (“ABATE”); Energy Michigan, Inc.; Michigan Energy Innovation Business Council and Institute for Energy Innovation (“MEIBC”); the Independent Power Producers Coalition of Michigan (“IPPC”)<sup>1</sup>,

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<sup>1</sup> Kent County, MI; City of Beaverton, MI; Energy Developments, Inc. f/k/a Granger; Boyce Hydro Power, LLC; White’s Bridge Hydro Co.; Black River, L.P.; Elk Rapids Hydroelectric Power, LLC; and Michiana Hydroelectric Co.

Solar Energy Industries Association, Inc. (“SEIA”); the Michigan Chemistry Council; Michigan Electric Transmission Company, LLC (“METC”); Cypress Creek Renewables, LLC; Residential Customer Group (“RCG”); Great Lakes Renewable Energy Association (“GLREA”); Attorney General Bill Schuette (“Attorney General”); Midland Cogeneration Ventures, LP (“MCV”); Environmental Law & Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar (collectively “ELPC”); and the Biomass Merchant Plants (“BMPs”)<sup>2</sup> intervened in this proceeding. 1 TR 10.

On August 30, 2018, a motion hearing was held to consider ELPC’s motion to strike Company direct testimony and two exhibits which presented PURPA related proposals as part of the Company’s PCA. Following the motion hearing, the ALJ granted ELPC’s motion in a September 10, 2018 Ruling. On October 5, 2018, the Commission issued an Order which granted applications for leave to appeal filed by the Company, the Attorney General, and ABATE, and overturned the ALJ’s Ruling. Among other things, the Commission found that “Section 6t requires a comprehensive, holistic examination of resource planning and costs, and that examination cannot exclude PURPA.” MPSC Case No. U-20165, October 5, 2018 Order (“October 5, 2018 Order”), page 17. The Commission further found that “[a]s Consumers has presented its unique PCA in the IRP, the PURPA-based issues and the Section 6t review are inextricably linked.” October 5, 2018 Order, page 21.

Evidentiary hearings in this case commenced on November 15, 2018 and concluded on November 20, 2018. The record in this case consists of 2,928 pages and hundreds of exhibits. Pursuant to the schedule established by the ALJ, initial briefs are due December 21, 2018, and

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<sup>2</sup> The BMPs include: Cadillac Renewable Energy, LLC; Genesee Power Station, LP; Grayling Generating Station, LP; Hillman Power Company, LLC; TES File City Station, LP; Viking Energy of Lincoln, Inc.; and Viking Energy of McBain, Inc.

reply briefs are due January 11, 2019. A Proposal for Decision target date is set for February 18, 2019.

**B. Executive Summary And Overview Of Company Requests**

Company witness Richard T. Blumenstock, Executive Director of Electric Supply, provided an overview of the Company's filing and requested relief. 6 TR 222-260. This overview specifically addressed the Company's compliance with statutory and regulatory IRP requirements, the development of the IRP, the resources proposed by the Company in the PCA, and the approvals sought by the Company in this case.

Exhibit A-1 (RTB-1) details each IRP filing requirement and the corresponding location of responsive information in the Company's filing. Furthermore, as required by the Commission's filing requirements, the Company presented an IRP Report which, among other things, details the Company's existing electric generating fleet and PPAs, resource adequacy through 2040, and analysis and decisions in selecting the PCA and proposed resource acquisition strategy. See Exhibit A-2 (RTB-2). The Company's filing meets the statutory requirements in MCL 460.6t, as well as the requirements in the Commission's IRP filing requirements, as approved in Case No. U-15896, *et al.* 6 TR 227.

The Company's modeling process used for developing the IRP was rigorous and comprehensive, consistent with good utility practice, followed all applicable Commission rules, and ultimately ensures the identification of the most reasonable and prudent resources to serve customers in a cost-effective and reliable manner. 6 TR 226-227. As required by Case No. U-18418, the Company's IRP considered three different scenarios: (i) Business As Usual ("BAU"); (ii) Emerging Technology ("ET"); and (iii) Environmental Policy ("EP"). In addition to these three scenarios, the Company also considered a collection of sensitivities which were

required to be evaluated on each of the scenarios. The Company also modeled three additional scenarios that mirrored the mandated scenarios described above, but used the Company's natural gas price forecast instead of the Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") natural gas price forecast mandated to be used by the Commission.

The Company started the IRP process with identification of the planning objectives and the engagement of stakeholders, both the general public and parties that typically intervene in the Company's electric rate case proceedings. The Company's efforts then transitioned to development of scenarios and sensitivities representing a wide range of potential future outcomes. Once scenarios and sensitivities were established, the Company completed extensive modeling and analytical work with resource planning software. The results of this modeling and analytical work were reviewed from the perspective of reasonableness in assumptions and alignment with planning objectives. The resulting portfolio of resources became the PCA. The Company then ran the PCA through all applicable scenarios and sensitivities to understand its performance under all study conditions. *See generally* 6 TR 232-244.

Results of the above analysis were then assessed using the Company's risk analysis to ensure that the PCA was robust under the reasonable range of outcomes represented by the scenarios and sensitivities, and to ensure that the PCA represented the most reasonable and prudent means of meeting the Company's energy and capacity needs . 6 TR 243. The Company's risk assessment methodology, which is consistent with the risk assessment methodology mandated by the Commission in Case Nos. U-15896 *et al.*, used a three-step process to assess the levels of risk related to selecting a resource portfolio. After completing its risk assessment, the Company determined that the PCA provides the least risk to customer

costs, when compared to the other resource plans developed in the IRP. The Company's risk assessment was then validated by an independent third party analysis.

Based on the results of a retirement analysis of J.H. Campbell ("Campbell") Units 1 and 2 and Karn Units 1 and 2 (collectively the "Medium 4"), the Company's PCA proposes to retire Karn Units 1 and 2 in 2023, prior to the end of the design lives of these units in 2031. 6 TR 249-250. To backfill the capacity lost by retiring these units early, the Company is proposing to utilize CVR, which will achieve 54 MW of capacity value by June 1, 2023; EWR, which will achieve 76 MW of incremental capacity value by June 1, 2023; and DR, which will achieve 71 MW of incremental capacity value by June 1, 2023. 6 TR 252-253. The Company also intends to leverage solar generation resources which are available as part of the Company's Renewable Energy Plan ("RE Plan") and the Company's plan to replace a large capacity need in 2030. 6 TR 253.

The Company's PCA also proposes a plan to backfill the capacity lost by the expiration of the MCV PPA in 2030, the retirement of Campbell Units 1 and 2 and Karn Units 3 and 4 in 2031, and the retirement of Campbell Unit 3 in 2039. 6 TR 254-255. To backfill the capacity lost by these units, the Company is proposing to utilize CVR, which will achieve 111 MW of capacity value by 2028; EWR, which will achieve 361 MW of incremental capacity value by 2040; DR, which will achieve 539 MW of incremental capacity value by 2030; solar generation resources, which will achieve 6,350 MW by 2040; and battery resources, which will provide 50 MW of capacity value in 2032 and will increase to 450 MW of capacity value by 2040. 6 TR 255.

Furthermore, as part of the PCA, the Company is seeking Commission approval of the investments in EWR, DR, and CVR resources that the Company will incur in the three years

following Commission approval of this IRP and the capacity value provided by these resources. 6 TR 258-259. Specifically, the Company is requesting the Commission to pre-approve the recovery of: (i) CVR deployment achieving a total peak load reduction of 44 MW (incremental 40 MW) by June 1, 2022 with a capital cost of \$8,924,600 and a total Operations and Maintenance (“O&M”) cost of \$666,600; (ii) an EWR increase from 1.5% to 2.0% per year achieving total EWR peak load reductions of 718 MW (incremental 52 MW from current EWR Plan) by June 1, 2022 with a capital cost of \$0 and incremental O&M cost of \$161,589,035; and (iii) DR expansion achieving total peak load reduction of 607 MW (an incremental 238 MW from 2019 levels proposed in the Company’s pending electric rate case) by June 1, 2022 with a capital cost of \$21,028,357 and a total O&M cost of \$36,272,652. 6 TR 259.

Because the PCA proposes the retirement of Karn Units 1 and 2 in 2023 before the end of design lives of these units, and before the remaining book balance would be recovered through traditional depreciation rates, the Company is seeking approval of a regulatory asset for the remaining book balance and costs of removal for those units. 6 TR 259-260. The Company is also proposing to move to a competitive bidding process for the future procurement of capacity—which means that the Company is proposing a new methodology for determining PURPA avoided cost rates, as well as determining the Company’s capacity needs or sufficiency for purposes of PURPA. 6 TR 260. Because this methodology entails a competitive-bid framework for procuring capacity, the Company is also seeking approval of a proposed FCM on PPAs. 6 TR 260.

In the Company’s initial filing, the Company proposed that the determination of the Company’s capacity obligations pursuant to PURPA would be based on a three-year capacity forecast. However, at the rebuttal stage of this proceeding, the Company agreed to Staff’s

proposal to use a five-year capacity forecast for determining PURPA capacity obligations. The Company's agreement with Staff's position is conditioned on a finding by the Commission that the Company has no PURPA capacity need so long as the Company is implementing the PCA, as approved by the Commission.

The Company's PCA is an integrated proposal that ties the evolution of the Company's resource portfolio to numerous proposals presented in this case (i.e., recovery of Karn Units 1 and 2 remaining book balance, new methodology for determining avoided costs pursuant to PURPA, and a FCM for PPAs) which are necessary to make that resource portfolio evolution successful. 6 TR 260. Since the Company's PCA is a fully integrated proposal with numerous components, modification 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 not modified or rejected. As such, 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.

The components of the Company's PCA, as discussed above, will dramatically change Michigan's energy future and will result in a clean, affordable, and reliable resource plan for customers. The Company is seeking Commission approval of its PCA as the most reasonable and prudent means of meeting the Company's energy and capacity needs.

## **II. DEVELOPMENT OF IRP**

The Company has developed an IRP that meets the Company's commitment to the triple bottom line of *People, Planet, and Prosperity* while simultaneously resulting in the most reasonable and prudent as the most reasonable and prudent means of meeting the Company's energy and capacity needs, pursuant to MCL 460.6t(8)(a). Development of this plan required significant modeling effort and consideration of many different costs, regulations, communities,

customers, and environmental impacts. Furthermore, in compliance with the Commission's orders in Case Nos. U-17990 and U-18322, the Company assessed whether continued operation of the Medium 4 units is in the best interest of customers. The different components of the IRP development process are addressed in detail below.

**A. Planning Objectives**

The Company's planning objectives, which are based upon a commitment to *People*, *Planet*, and *Prosperity*. 6 TR 232-236. As explained by Mr. Blumenstock these planning objectives to align with the following planning objectives of the Commission: (i) resource adequacy and capacity requirements; (ii) compliance with environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risk; (vi) diversity of generation portfolio; and (vii) reasonable and cost effective EWR and renewables. See MCL 460.6t(8)(a). There were also several key decisions which allowed the Company to develop the most reasonable and prudent means of meeting short- and long-term energy and capacity needs.

With respect to the *People* component of the Company's planning objectives, the Company considered the impact of its PCA on communities, employees, and customers. 6 TR 233. Reliability is also central to the Company's *People* commitment. The Company considered reliability by ensuring that the PCA provided sufficient capacity to serve anticipated peak electric load plus applicable Planning Reserve Margin Requirement ("PRMR") and Local Clearing Requirement ("LCR") results in reliable energy supply. 6 TR 233. The Company's commitment to *People* further included listening to customers regarding their desire for Michigan's energy future, and considering and minimizing customer rate impact. 6 TR 234.

From a *Planet* perspective, the Company ensured that the PCA met the Renewable Portfolio Standard ("RPS"), as specified in Michigan law, and complied with applicable state

and federal environmental regulations. 6 TR 234. Transitioning to a clean and lean resource portfolio positions the Company to achieve compliance with potential environmental regulation that may be imposed in the future, such as carbon dioxide emissions regulations, which reduces future financial risk to customers. 6 TR 234. The Company's PCA must also align with the Company's Clean Energy Goal which calls for reducing carbon emissions by 80% (from 2005 levels) and no longer using coal to generate electricity, both by 2040. 6 TR 234. The Company's Clean Energy Goal extends beyond the compliance level required by current law and illustrates the Company's deep commitment to protecting the environment while maintaining competitive rates for our customers.

Finally, with respect to the *Prosperity* component of the Company's planning objectives, Mr. Blumenstock explained that the PCA must provide for both a financially healthy utility that attracts capital investment for needed electric infrastructure, and affordable bills for customers. 6 TR 234. The traditional utility regulatory model provides utility investors with an opportunity to earn returns on capital investment in new infrastructure and gives little incentive for utilities to utilize PPAs to meet energy and capacity needs. The Commission's adoption of financial compensation for utilizing PPAs, as provided for in MCL 460.6(t)(15), is critical to creating a stable, sustainable regulatory, and financial model that drives utilization of PPAs that benefit the Company's customers and the state of Michigan. 6 TR 234-235.

The development of the Company's PCA considered and ensured customer bill affordability and competitive pricing, which are both critical to support the lives of the Company's residential customers and the businesses of its Commercial and Industrial ("C&I") customers. The PCA's modular supply plan provides a scalable supply portfolio that minimizes

potential for surplus capacity, diversifies supply resources, insulates the Company and its customers from commodity price risks, and protects against high customer rates. 6 TR 235.

There were four key decisions which allowed the Company to develop the most reasonable and prudent means of meeting short- and long-term energy and capacity needs. 6 TR 235-236. First, as directed by the Commission in its March 29, 2018 Order in Case No. U-18322, the Company analyzed the best plan for the disposition of the Medium 4, which included consideration of early retirement in years 2021 and 2023 as well as continued operation until 2031, consistent with the design lives of these units. Second, the Company had to ensure the PCA achieved all planning objectives set forth by the Commission and the Company. Third, to seek competitive pricing for supply options, the Company developed a new manner for procuring capacity through competitive bids and using this complete bidding process to establish PURPA avoided costs. Fourth, because the Company is proposing a competitive-bid methodology, the FCM was developed to earn a fair return on PPAs—a strategy that the Company believes is aligned with providing the lowest costs to customers.

#### **B. Stakeholder Outreach**

During the development of the IRP, the Company conducted a stakeholder engagement process consisting of public and technical stakeholder outreaches. 6 TR 237-240. Each outreach event was designed to provide transparency, education, and an opportunity to provide input to the IRP. These outreach events were designed to educate participants about the purposes and process of an IRP, and invited participants to share their ideas, suggestions, and opinions on meeting Michigan's future energy and capacity needs. A report detailing the Company's public outreach efforts is provided as part of the Company's IRP Report, Exhibit A-2 (RTB-2).

With respect to the Company's general public outreach, the Company held two public open house events. 6 TR 238. The first open house was held on January 29, 2018 at the Kellogg Center in East Lansing and the second open house was held on February 12, 2018 at the Company's John Russell Leadership Center in Grand Rapids. The Company widely promoted these events through press releases, customer outreach, owned media, social media, employee communications, and through the Company's State and Federal Governmental Affairs staff. Mr. Blumenstock explained that these events consisted of four main areas of interest: (i) overview of the IRP; (ii) the environment; (iii) Emerging Technologies ("ET"); and (iv) renewable resources. To ensure participants wishing to make a formal comment, the participants were provided with the opportunity to do so, each participant was allowed to provide hand-written comments or verbal comments recorded by a stenographer. 6 TR 238.

In addition to the general public events, the Company held technical stakeholder workshops with those expected to be highly involved in the technical aspects of the IRP. 6 TR 238-239. The parties that were invited to participate in these stakeholder technical workshops included, but were not limited to, the parties that were granted intervention in the Company's last electric rate case, Case No. U-18322. The technical workshop sessions were held on December 12, 2017 and February 27, 2018 in Jackson, Michigan. The technical workshops provided an opportunity to explain the modeling and analytical approach to the IRP, to take questions, and to solicit feedback on the technical aspects of the IRP. Mr. Blumenstock explained that the format of these technical workshops included:

“A presentation of information by the Company on the project schedule and status, modeling approaches and explanations, information sources, and, with respect to the second technical conference, responses to comments formally provided by the stakeholders;

“An opportunity for stakeholders to ask questions on the information presented or a topic that was not presented. During this segment of the technical conference, a verbal response was provided to each question; and

“An opportunity for each stakeholder to make comments. To ensure accurate portrayal of stakeholder comments, an electronic document capturing the comments was projected on screens for all stakeholders to see. Stakeholders were also asked to confirm the accuracy of each comment as written.” 6 TR 239.

The above outreach events successfully resulted in a constructive discussion of the IRP and also provided the Company with numerous comments and recommendations to consider during the development of the IRP. Comments received during these events focused on developing additional renewables and clean energy resources, and also included a focus on the content of the regulatory filing, minimizing time constraints in the regulatory process, and providing an opportunity for the Company to perform and provide analysis on behalf of technical stakeholders. 6 TR 239. As noted by Mr. Blumenstock, the Company took action or responded to all stakeholder comments. 6 TR 239-240.

**C. Transmission Outreach**

The Company also engaged a local transmission owner in its IRP process. As explained in detail by Company witness Donald A. Lynd the Company reached out to, and established meetings with, METC, a subsidiary of ITC Holdings Corporation, to discuss the IRP and request METC’s analysis of various future transmission scenarios and assessment of the effects on the transmission system. 6 TR 672. METC is the predominant owner of electric transmission systems in the Company’s retail service territory and operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in Michigan and surrounding areas. 6 TR 272-273. As Mr. Lynd explained, “[t]hrough ITC’s joint planning approach, these meetings also provided the perspectives of ITC Transmission (‘ITCT’), also a

subsidiary of ITC, which owns a fully-regulated high-voltage system that transmits electricity to local electricity distribution facilities in the eastern portion of the lower peninsula of Michigan.” Mr. Lynd attended these meetings as a representative of the Company’s transmission business. 6 TR 273. Four meetings were held as part of the IRP process on November 16, 2017; January 11, 2018; March 14, 2018; and April 17, 2018. See Exhibit A-96 (DAL-1) for the minutes from each meeting.

**D. Modeling**

**1. Modeling Assumptions**

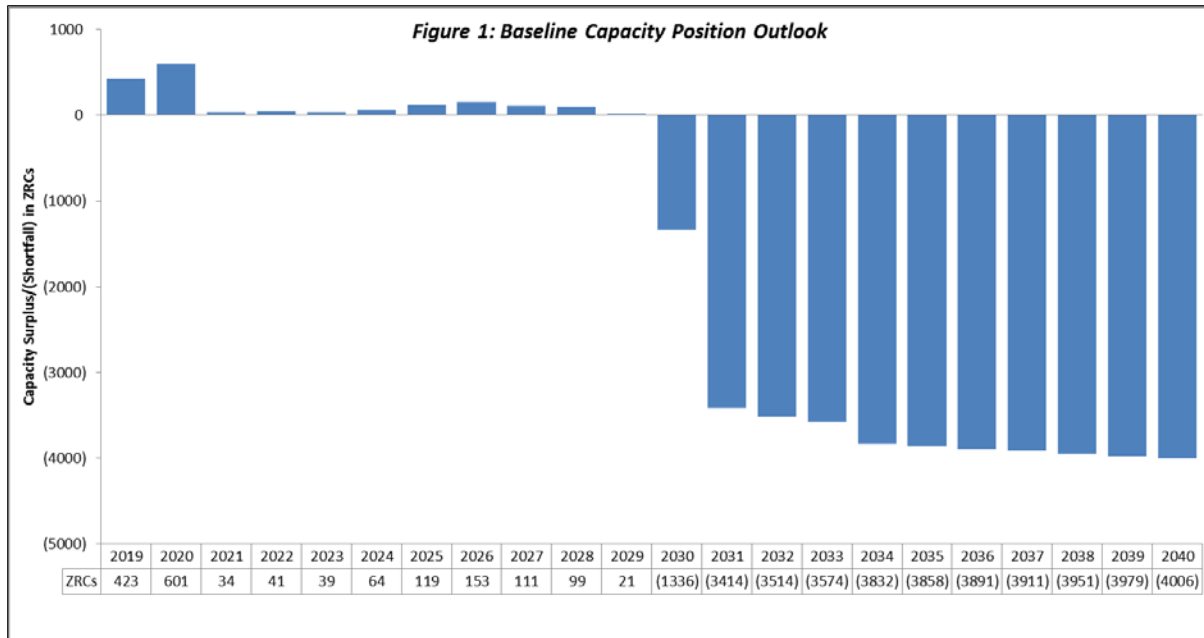
Consumers Energy developed the PCA based on the types and timing of the resources chosen by computer optimization models that select the least-cost portfolio of resources available. 6 TR 425. Using ABB Enterprise Software, Inc.’s (“ABB”) Strategist software, in conjunction with ABB’s PowerBase database, Consumers Energy optimized its resource plan and alternatives. 6 TR 437. Inputs to these optimization models included a variety of technical, cost, and environmental data. 6 TR 426. 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. 6 TR 431. A detailed summary of the amount of capacity anticipated from all existing assets, and the associated year those assets are available (assuming a 2023 retirement of Karn Units 1 and 2), is shown in Exhibit A-12 (STW-3). Major modeling assumptions were developed 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, CVR, and incremental DR; (vi) capital and operating costs

for construction of new supply-side resources; (vii) network upgrade costs for all new generation resources; (viii) fuel price forecasts for coal, natural gas, and oil; (ix) existing PPAs with Non-Utility Generators (“NUGs”); and (x) economic parameters such as the discount rate and fixed charge rate. 6 TR 432-435.

**a. Baseline Capacity Position**

Company witness Thomas P. Clark, Director of Merchant Operations and Resource Planning, explained that the purpose of an IRP is to identify if additional resources will be needed to serve customers’ energy and capacity needs based on forecasts of future load and assumptions regarding the operation and use of existing resources. 7 TR 876. The first step in this process involves the determination of a capacity position. 7 TR 876-877. The Company’s Baseline Capacity Position provides the Company’s current capacity position (i.e., excluding the resources proposed in the PCA) and includes the latest forecasts of peak electric demand and the demand-side and supply-side resources currently available to the Company. 7 TR 877.

The Company’s Baseline Capacity Position, as illustrated in Figure 1 below, forecasts a surplus of capacity from 2019 through 2029. 7 TR 878. The first capacity shortfall of approximately 1,300 Zonal Resource Credits (“ZRCs”) occurs in the year 2030 and then increases to approximately 3,400 ZRCs in 2031. A capacity need then persists from 2031 to the end of the planning period in 2040.

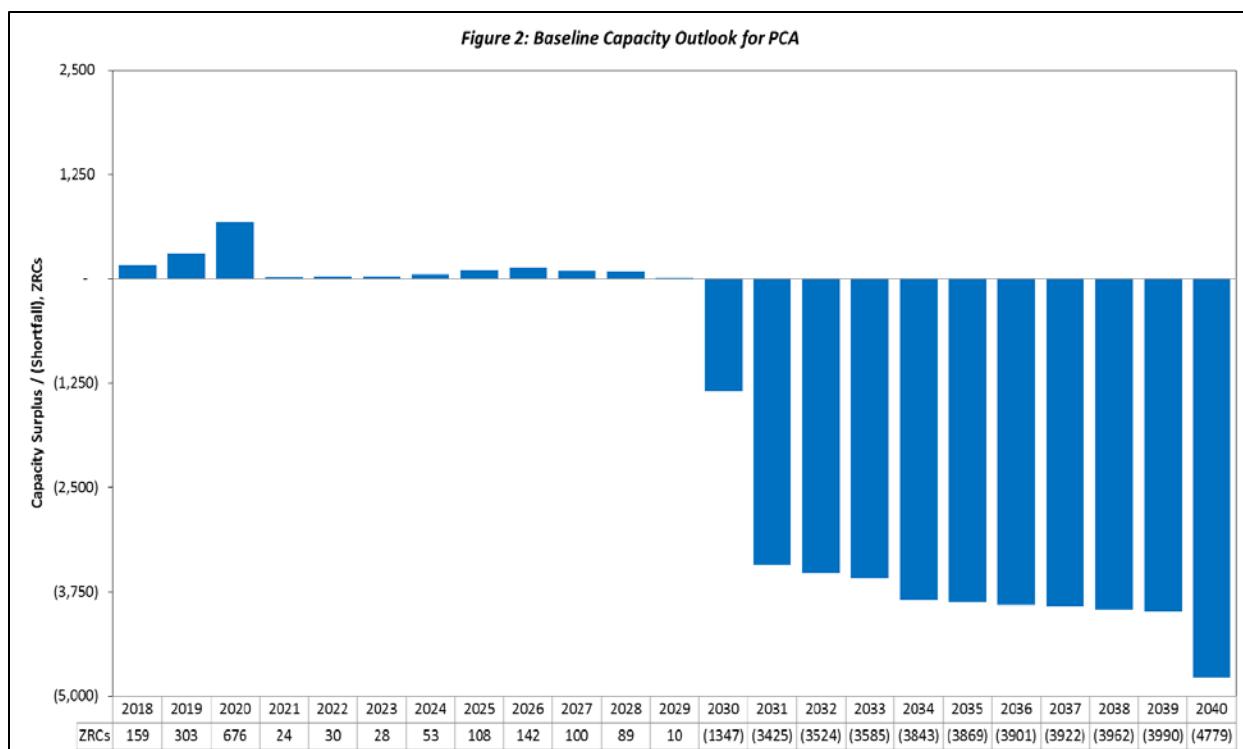


Mr. Clark provided a description of the major assumptions initially included in the Company’s Baseline Capacity Position. The major assumptions include: (i) retirement dates for Campbell Units 1 and 2, Karn Units 1 and 2, and Karn Units 3 and 4 which occur during Midcontinent Independent System Operator, Inc. (“MISO”) Planning Year 2030 through 2031; (ii) continued operation of the Jackson (“Jackson”) and Zeeland (“Zeeland”) Generating Plants through the end of the planning period; (iii) the termination of the Palisades Nuclear Energy Plant (“Palisades”) PPA on April 11, 2022; (iv) the extension of the MCV PPA from March 16, 2025 to 2030<sup>3</sup>; (v) the continued expansion of existing DR programs and continued levels of the General Interruptible Provision and the Energy Intensive Primary Program; (vi) energy efficiency savings of 1.5% in 2018, as approved by the Commission in Case No. U-17771; (vii) 550 MW of wind resources which either has, or will be, addressed in the RE Plan; and (viii) the Amendment No. 2 to the T.E.S Filer City Station Limited Partnership (“Filer City”)

<sup>3</sup> The terms of the MCV PPA provide the Company with a unilateral right to extend the terms of the MCV PPA for five years from March 16, 2025 at a reduced capacity rate.

PPA, as approved by the Commission in Case No. U-18392, which provides for the commercial operation of the converted Filer City Plant in Planning Year 2019. 7 TR 878-879.

Mr. Clark also addressed how the Company's Baseline Capacity Position was adjusted during the development of the IRP. These adjustments were as follows: (i) 150 MW of PURPA Qualifying Facility ("QF") capacity was added to the capacity forecast based on the Commission's directive in the Company's PURPA Avoided Cost proceeding, Case No. U-18090; (ii) the commercial operation date of the converted Filer City Plant was adjusted from the Planning Year 2019 to Planning Year 2020 based upon expected approval of Amendment No. 2 from the Federal Energy Regulatory Commission ("FERC"); (iii) the planned retirement of Campbell Unit 3 was adjusted from year-end 2040 to year-end 2039 to align with the Company's Clean Energy Goals; and (iv) minor downward adjustments were made to the level of DR in the short-term period of the capacity forecast to allow for more of a consistent ramp of DR resources over the planning period. 7 TR 879-880. Mr. Clark explained that, with these adjustments, the Company continues to have a surplus of capacity until a persistent need occurs in the year 2030. 7 TR 880. This is illustrated in Figure 2 below:



**b. Existing Electric Generating Assets And Costs**

Company witness Norman J. Kapala, Consumers Energy’s Executive Director of Coal Generation, described the Company’s existing non-renewable generation resources and costs. Mr. Kapala provided a description of the coal-fired generation units in the following table:

RESOURCE	LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	GENERATING CAPACITY (MW)
Campbell Unit 1	West Olive, MI	1962	56	2031	13	Active	259
Campbell Unit 2	West Olive, MI	1967	51	2031	13	Active	348
Campbell Unit 3	West Olive, MI	1980	38	2040	22	Active	780
Karn Unit 1	Essexville, MI	1959	59	2031	13	Active	255
Karn Unit 2	Essexville, MI	1961	57	2031	13	Active	260

8 TR 1101. The Company owns 93% of Campbell Unit 3, with other entities owning the remaining 7%; the generating capacity shown in the above table reflects the Company’s ownership share. *Id.*

Mr. Kapala also provided a description of the Company’s oil- and gas-fired units in the following table:

<b>RESOURCE</b>	<b>LOCATION</b>	<b>IN-SERVICE DATE</b>	<b>AGE (years)</b>	<b>RETIREMENT DATE</b>	<b>REMAINING EST. TIME OF OPERATION (years)</b>	<b>LICENSING STATUS</b>	<b>GENERATING CAPACITY (MW)</b>
Karn Unit 3	Essexville, MI	1975	43	2031	13	Active	600
Karn Unit 4	Essexville, MI	1977	41	2031	13	Active	608
Zeeland CC	Zeeland, MI	2002	16	2030	12	Active	527
Zeeland 1A	Zeeland, MI	2002	16	2030	12	Active	159
Zeeland 1B	Zeeland, MI	2002	16	2030	12	Active	157
Jackson CC	Jackson, MI	2002	16	2030	12	Active	542
Campbell Unit A	West Olive, MI	1968	50	2019	1	Active	12
Gaylord Unit 1	Gaylord, MI	1966	52	2019	1	Active	12
Gaylord Unit 2	Gaylord, MI	1966	52	2019	1	Active	12
Gaylord Unit 3	Gaylord, MI	1966	52	2019	1	Active	11
Straits Unit 1	Mackinaw City, MI	1969	49	2019	1	Active	6

8 TR 1101.

Finally, Mr. Kapala summarized the Company's hydroelectric units as follows:

<b>RESOURCE</b>	<b>LOCATION</b>	<b>IN-SERVICE DATE</b>	<b>AGE (years)</b>	<b>RETIREMENT DATE</b>	<b>REMAINING EST. TIME OF OPERATION (years)</b>	<b>LICENSING STATUS</b>	<b>GENERATING CAPACITY (MW)</b>
Alcona	Alcona County, MI	1924	94	n/a	n/a	Active	3
Allegan	Allegan County, MI	1936	82	n/a	n/a	Active	1
Cooke	Iosco County, MI	1911	107	n/a	n/a	Active	7
Croton	Newaygo County, MI	1907	111	n/a	n/a	Active	4
Five Channels	Iosco County, MI	1912	106	n/a	n/a	Active	6
Foote	Iosco County, MI	1918	100	n/a	n/a	Active	3
Hardy	Newaygo County, MI	1931	87	n/a	n/a	Active	32
Hodenpyl	Wexford County, MI	1925	93	n/a	n/a	Active	5
Loud	Iosco County, MI	1913	105	n/a	n/a	Active	5
Mio	Oscoda County, MI	1916	102	n/a	n/a	Active	2
Rogers	Mecosta County, MI	1906	112	n/a	n/a	Active	3
Tippy	Manistee County, MI	1918	100	n/a	n/a	Active	6
Webber	Ionia County, MI	1907	111	n/a	n/a	Active	7

8 TR 1102.

Mr. Kapala also described the Company's pumped storage units:

<b>RESOURCE</b>	<b>LOCATION</b>	<b>IN-SERVICE DATE</b>	<b>AGE (years)</b>	<b>RETIREMENT DATE</b>	<b>REMAINING EST. TIME OF OPERATION (years)</b>	<b>LICENSING STATUS</b>	<b>GENERATING CAPACITY (MW)</b>
Ludington Units 1-6	Ludington, MI	1973	45	2049	31	Active	1097

8 TR 1102. The Company owns 51% of Ludington Pumped Storage Plant (“Ludington”) Units 1 through 6, with DTE Energy Electric Company owning the remaining 49%; the generating capacity shown in the table above reflects the Company’s ownership share. *Id.*

Mr. Kapala testified regarding Consumers Energy’s projected capital expenditures, major maintenance expenses, and base O&M expenses at the Medium 4, as well as Campbell Unit 3, and Karn Units 3 and 4. 8 TR 1102. His Exhibit A-41 (NJK-1), provided the projected capital expenditures (on page 1), major maintenance expenses (on page 2), and base O&M expenses (page 3), for the Medium 4 for the period January 1, 2017 through May 31, 2031. The exhibit evaluated the BAU scenario (i.e., retirement of the Medium 4 on May 31, 2031), and then evaluated the following eight early retirement scenarios:

- Retirement of Karn Units 1 and 2 on May 31, 2021;
- Retirement of Karn Units 1 and 2 on May 31, 2023;
- Retirement of Campbell Unit 1 on May 31, 2021;
- Retirement of Campbell Unit 1 on May 31, 2023;
- Retirement of Campbell Unit 2 on May 31, 2021;
- Retirement of Campbell Unit 2 on May 31, 2023;
- Retirement of Campbell Units 1 and 2 on May 31, 2021; and
- Retirement of Campbell Units 1 and 2 on May 31, 2023.

Exhibit A-41 (NJK-1), page 1, showed the Company’s projected capital expenditures for the Medium 4 in each of the scenarios listed above for the period of January 1, 2017 through May 31, 2031. 8 TR 1103. For each of the eight early retirement scenarios, the exhibit presents both the total expenditures that would be made in each respective scenario, and the difference in

expenditures relative to the BAU scenario.<sup>4</sup> For example, lines 2 and 3 reflect the early retirement scenarios for Karn Units 1 and 2; for both of these scenarios the expenditures for Campbell Units 1 and 2 would be the same as those shown in the BAU scenario. The exhibit also reflects the early retirement scenarios for Campbell Units 1 and 2, including the incremental costs at Campbell Unit 3 for the Campbell Units 1 and 2 early retirement scenarios. The exhibit did not include costs of removal for any of the scenarios, nor environmental costs related to Steam Electric Effluent Guidelines (“SEEG”) and Clean Water Act (“CWA”) Section 316(b) (“316(b)”).

Exhibit A-41 (NJK-1), page 2, reflects the Company’s projected total major maintenance expenses for the Medium 4 at Campbell Unit 3, and at Karn Units 3 and 4, in each of the eight early retirement scenarios for the period January 1, 2017 through May 31, 2031. For each early retirement scenario, the exhibit shows both the total expenses that would be incurred, and the difference in expenses relative to the BAU scenario. The exhibit did not include environmental costs, such as those related to SEEG and 316(b).

In Exhibit A-41 (NJK-1), page 3, Mr. Kapala provided the Company’s projected total base O&M expenses for the Medium 4 at Campbell Unit 3, and at Karn Units 3 and 4 in each of the eight early retirement scenarios for the period January 1, 2017 through May 31, 2031. 8 TR 1115-1116. For each scenario, the exhibit explains both the total expenses that would be made in each respective scenario and the difference in expenses relative to BAU. The exhibit did not include environmental costs such as those related to SEEG and 316(b).

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<sup>4</sup> Mr. Kapala also provided the projected capital expenditures and costs of removal for the Company’s remaining generation units. 8 TR 1128; Exhibit A-46 (NJK-6). The Company did not, however, account for the capital expenditures shown in Exhibit A-46 (NJK-6) in its IRP modeling. Rather, the IRP modeling assumed that the generation units listed in Exhibit A-46 (NJK-6) would continue operating until reaching the end of their lifespan when their book values are fully depreciated. *Id.*

Mr. Kapala also provided the Company's projected capital expenditures for the Medium 4 for each calendar year for the period January 1, 2017 through May 31, 2031 in the BAU scenario. Exhibit A-42 (NJK-2), page 1. Mr. Kapala's testimony described in detail the Company's projected capital expenditures for years 2018 through 2031. 8 TR 1106-1115. He also provided the Company's projected capital expenditures for Karn Units 1 and 2 if those units retired on May 31, 2021 or on May 31, 2023, and showed that the Company would avoid \$108,410,000 in capital expenditures if it retired Karn Units 1 and 2 on May 31, 2023 pursuant to the PCA. 8 TR 1115-1116; Exhibit A-42 (NJK-2), page 2. Similarly, Exhibit A-42 (NJK-2), pages 3 through 5, showed the Company's projected capital expenditures for the period January 1, 2017 through May 31, 2031, under various retirement scenarios for Campbell Units 1 and 2. 8 TR 1115-1116.

Mr. Kapala provided the Company's projected major maintenance expenses for the Medium 4 for each calendar year over the period from January 1, 2017 through May 31, 2031 in the BAU scenario. 8 TR 1117; Exhibit A-43 (NJK-3), page 1. The Company used the expenses in Exhibit A-43 (NJK-3), page 1, line 1, for 2017 in the Company's IRP modeling. Mr. Kapala explained in detail the basis for the projected BAU major maintenance expenses. 8 TR 1117-1120. Exhibit A-43 (NJK-3), page 2, showed the Company's projected major maintenance expenses for Karn Units 1 and 2 for the scenarios in which Karn Units 1 and 2 retire on May 31, 2021, or on May 31, 2023, for the period January 1, 2017 through May 31, 2031. Exhibit A-43 (NJK-3), page 2, also showed the difference in expenses for each calendar year relative to the BAU scenario, and showed that the Company would avoid \$20,372,000 in major maintenance expenses if Karn Units 1 and 2 retired on May 31, 2023, pursuant to the PCA. Mr. Kapala likewise sponsored the Company's projected major maintenance expenses for each calendar year

from January 1, 2017 through May 31, 2031 under various retirement scenarios for Campbell Units 1 and 2.

Mr. Kapala also provided the Company's projected base O&M expenses for the Medium 4, for Karn Units 3 and 4, and for Campbell Unit 3 for each calendar year over the period from January 1, 2017 through May 31, 2031 in: (i) the BAU scenario; (ii) the scenarios in which Karn Units 1 and 2 retired in 2021 or 2023; (iii) the scenarios in which Campbell Unit 1 retired 2021 or 2023 (8 TR 1124; Exhibit A-44 (NJK-4), page 3); (iv) the scenarios in which Campbell Unit 2 retired 2021 or 2023 (8 TR 1124-1125; Exhibit A-44 (NJK-4), page 4); and (v) the scenarios in which Campbell Units 1 and 2 retired 2021 or 2023. 8 TR 1124-1125.<sup>5</sup>

Mr. Kapala testified that it would not be economical to separate Campbell Units 1 and 2 from one another, with one unit retiring and the other remaining in operation. 8 TR 1127. Campbell Units 1 and 2 operate as a single-facility, with a common staff, and share internal systems (e.g., fuel supply and water supply). If one unit retired, and the other remained in operation, the efficiencies gained through this single-facility arrangement would be lost. *Id.*

Mr. Kapala also addressed the Company's unavoidable, avoidable, and incremental costs for each of the early retirement scenarios. He testified that unavoidable costs are those that the Company would have to make even if it retired one or two of the Medium 4 Units in 2021 or 2023 (e.g., to ensure safety and reliability). 8 TR 1134-1135. Avoidable costs are scheduled

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<sup>5</sup> Mr. Kapala explained that the projected costs for the Medium 4 were different from those in the Company's pending electric general rate case, Case No. U-20134. 8 TR 1125. The reason was that, in order to meet the filing deadline for this IRP, the Company began its modeling process in late 2017. Subsequently, the Company identified several additional projects necessary to maintain reliability at Campbell Units 1 and 2. Once the Company's IRP modeling indicated that the best option for the Company would be to operate Campbell Units 1 and 2 until 2031, the need for the additional reliability work during the 2019 electric rate case test year became even clearer. Therefore, those projects were added to the Company's filing in Case No. U-20134. The Company did not change the costs that were modeled for this IRP, because doing so would have prevented the modeling from being finished on time for this IRP filing. The additional projects largely represent work that would have been done in future years, but was pulled forward into 2019 in order to meet reliability needs. 8 TR 1126. The additional projects and costs are shown in Exhibit A-45 (NJK-5).

expenditures that the Company would forego if it retired one or two of the Medium 4 Units in 2021 or 2023. 8 TR 1135. Finally, incremental costs are those that the Company did not include in its base plans, but that it would add if it retired one or two of the Medium 4 Units in 2021 or 2023 (e.g., separation activity costs). Mr. Kapala provided the Company's unavoidable, avoidable, and incremental capital costs for each of the early retirement scenarios in his Exhibit A-48 (NJK-8) (which include separation activity costs), and he provided the Company's unavoidable, avoidable, and incremental major maintenance expenses for each of the early retirement scenarios in his Exhibit A-49 (NJK-9). 8 TR 1136-1138.

Company witness Teresa E. Hatcher, Director of Renewable Energy, provided an overview of Consumers Energy's existing renewable energy resources. The Company's existing renewable energy resources consist of 13 hydroelectric facilities, 2 operational wind farms, and 2 operational solar facilities. 8 TR 1700. Although discussed above, the Company also includes its hydroelectric facilities as its renewable energy resources because it receives Renewable Energy Credits ("RECs") from these facilities. The table below summarizes the Company's renewable generation portfolio including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:

Resource	In-Service Date	Age (years)	Estimated Retirement Date	Estimated Remaining Time of Operation	Licensing Status	Generating Capacity	Capacity Factor
Lake Winds	2012	6	2043	25	Active	100.8	30.3%
Cross Winds (Phase I)	2014	4	2045	27	Active	110.98	41.3%
Cross Winds (Phase II)	2018	0	2049	31	Active	43.7	41%
Solar Gardens – GVSU	2016	2	2041	23	Active	3	17%
Solar Gardens - WMU	2016	2	2041	23	Active	1	17%

Additionally, the Company is in the process of developing a research and development distributed roof-top solar installation, 500kW in size, to develop further understanding and expertise on the impacts of small distributed generation in existing urban infrastructures. 8 TR 1701.

**c. RPS**

In accordance with 2008 PA 295, as amended by 2016 PA 342 (“Act 342”), Consumers Energy is required to meet a 15% RPS by the year 2021 and work towards the goal of obtaining 35% combined renewable energy and EWR by 2025 to serve customers’ energy needs.

The Company’s RPS obligation is determined based on the average number of retail sales for the previous three years in accordance with MCL 460.1028(2)(b)(ii). 8 TR 1707; see Exhibit A-87 (TEH-2). In 2021, the Company projects to need 4,996,053 RECs to meet the 15% RPS. Exhibit A-87 (TEH-2). In order to meet the 15% RPS, in Case No. U-18231, the Company amended its previously-approved RE Plan by modifying its approved RE Plan to include new wind facilities of up to 525 MW and new solar facilities of up to 100 MW. The

facilities included in the RE Plan are proxy facilities, which are hypothetical projects included for planning purposes to meet the RPS. 8 TR 1702. Once a specific location, project, and technology are negotiated, the RE Plan will be amended, as appropriate, and approval of specific projects and contracts will be requested to fulfill the RE Plan and meet and maintain the RPS through the end of the RE Plan period in 2029. In developing its IRP, the Company aligned its IRP assumptions with the Company's ongoing RE Plan covering years 2019 through 2029.

During the IRP planning process, consideration was given as to whether the proposed plan cost-effectively maintained the 15% renewable energy standard beyond the compliance period and to what extent the proposed plan would meet or exceed the 35% goal in the year 2025. As an input assumption, the IRP provides for 550 MW of new wind, which is generally consistent with the RE Plan. 8 TR 1704. Through the IRP, the Company planned for one 150 MW proxy wind project and one 200 MW proxy wind project to receive 100% of available Production Tax Credits ("PTCs"), and one 200 MW proxy wind project to receive 80% of available PTCs. The IRP, like the RE Plan, assumes that wind is the most economic choice to achieve the RPS by 2021. 8 TR 1705. Additionally, the IRP provides for the addition of 100 MW of solar in 2021. The 2021 proxy solar facility represents the RE Plan addition, aggregated, and pulled forward on the timeline. 8 TR 1705.

Through the combination of RECs and energy efficiency savings from EWR programs, the Company calculates the ability to meet the 35% goal. Under the PCA, the Company is on track to achieving the 35% in 2025 and forecasts achieving the 35% Goal in 2022, three years ahead of the statutory target. 8 TR 1708. If regulatory decisions are made to increase goals or requirements, the Company is well-positioned to address this type of regulatory change.

#### **d. Customer Renewable Energy Programs**

The Company has a number of customer renewable energy programs that are specifically designed to meet the needs of customers who want to further their own individualized renewable energy goals. The Large Customer Renewable Energy Pilot Program is designed to give large customers the ability to customize their renewable energy needs, while remaining administratively manageable for the Company. 8 TR 1710. The Solar Gardens Pilot Program is a program intended to provide interested customers, who may not have the ability or willingness to invest in their own private solar energy systems, an opportunity to participate in and benefit from solar energy. 8 TR 1710. The Green Generation Program is a popular customer program that currently provides a low cost option for customers to match their energy usage with a renewable resource. 8 TR 1710-1711. Lastly, the Net Metering Program allows customers to receive a credit for excess electricity generation that they may generate through their own renewable energy source. 8 TR 1711.

While the Company has a number of existing customer renewable energy programs in place, it continues to conduct market and customer research to understand renewable customer demand, and develop new programs or modify existing pilots, as appropriate, to meet customer demand. 8 TR 1711. For this IRP, through 2021, the Company is not expecting to reach the program limits for net metering that are currently in place. Nor does the Company anticipate that its existing customer renewable energy programs will be fully subscribed. However, the Company will continue to monitor the demand for renewable energy and adjust as customer demand dictates.

The IRP's PCA and glide path for future renewable development, especially solar, introduces flexibility to meet customer demand. This allows the Company to tailor its generation to the needs of the customer. As an example, the projected future 300 MW of incremental solar

in 2022 as part of the IRP glide path could be used to provide the Company potential options as demand develops for customer renewable energy programs. This demand could be met through electric rate cases, RE Plan, or Voluntary Green Pricing programs, as appropriate. 8 TR 1709. Thus, it enables the Company to meet its customers individualized needs.

**e. Assumptions For Renewable Technologies**

In addition to the planned expansion of renewable resources as part of the Company's RE Plan, the Company identified wind, solar, and battery storage technologies as viable resources in the IRP modeling. 6 TR 451. Company witness Sara T. Walz testified that the Company relied on data from IHS Markit to develop supply-side prototypes for wind generation, solar generation, and battery storage resources. 6 TR 451. These prototype resources included an estimated network upgrade expense associated with the capacity additions. 6 TR 451.

For the wind generation prototype units, the Company assumed that any expansion of wind capacity will occur out of state because of concerns that wind built in Michigan may not be cost-effective or feasible as a result of: (i) moratoriums on construction of wind and (ii) lower achievable capacity factors in the center of the state. 6 TR 452. The wind prototypes used in the Company's modeling have an installed capacity of 400 MW, an assumed capacity credit of 15.6%, and use Iowa as a proxy location. 6 TR 452. The Company assumed that the energy produced would be sold in Iowa, and modeled an expected price differential based on the historic lower energy prices in Iowa. 6 TR 452-453. IHS Markit data used to develop the wind prototype units include capital costs from the MISO West region, annual O&M costs, federal PTC rates, percent of PTC by year of commercial operation, and capacity factor for year online from the MISO West region. 6 TR 453-454. Confidential Exhibit A-15 (STW-6) provides additional detail on operating parameters and assumed costs of the prototype wind resources.

Confidential Exhibit A-16 (STW-7) provides a summary of the annual cost of capital for all renewable technologies.

For the solar generation prototype units, the Company modeled solar photovoltaic, utility scale, ground-mounted fixed tilt panels. 6 TR 455. The Company assumed expansion of solar generation would occur in Michigan, sized the prototype unit at 400 MW of installed capacity, and assumed a capacity credit of 50%. 6 TR 455. IHS Markit data used to develop the solar prototype units include capital costs from the MISO North region, annual O&M costs, and federal Investment Tax Credit (“ITC”) rates in percentage of capital investment. 6 TR 455. See also Confidential Exhibits A-15 (STW-6) and A-16 (STW-7) for additional operating parameters and cost details of the solar prototype units.

For the battery storage prototype units, the Company modeled four-hour duration lithium ion batteries, and assumed a 100 MW by 400 MW battery (or an installed capacity of 100 MW that can be delivered at maximum output for four consecutive hours). 6 TR 456-457. Capacity credit for the battery prototype is assumed to be nearly 100%. 6 TR 457. IHS Markit data used to develop the battery prototype units include capital costs for utility scale storage with a four-hour duration. 6 TR 457. Fixed O&M costs were estimated as 1.3% of capital costs based on an average of percentages provided in a November 2016 EIA report and a December 2016 Lazard report. 6 TR 457. See also Confidential Exhibits A-15 (STW-6) and A-16 (STW-7) for other operating and cost details related to the battery prototype units.

**f. Assumptions For Gas-Fueled Technologies**

Company witness Scott D. Thomas, Executive Director of Enterprise Project Develop, presented the cost estimates and operating parameters for the various gas-fueled technologies considered in the IRP. Confidential Exhibit A-51 (SDT-1) provides the capital and O&M cost

estimates, as well as the operating performance characteristics, utilized for the various gas-fueled technologies new sources of generation. This information was developed by the Company's engineering and estimating staff who utilized an estimating structure from the American Association of Cost Engineers International Recommended Practice No. 34R-05. Additionally, Consumers Energy commissioned HDR Engineering to develop a report titled "Natural Gas-Fired Simple and Combined Cycle Technology Assessment." 8 TR 1377. This report supplied industry information on gas generation technologies including plant configurations, performance, and operating and capital costs and schedules. 8 TR 1377. Indirect costs were also included in the cost estimates provided. 8 TR 1378. These assumptions were utilized by Company witness Walz as the capital and operation cost assumptions for Combined Cycle ("CC") and Combustion Turbine ("CT") units.

**g. Forecast Of Electric Sales, Maximum Demand, And System Output**

The Company, through its witness Eugene M.J.A. Breuring, presented the Company's historical annual electric deliveries and monthly peak demands, as well as the Company's forecasted electric deliveries, generation requirements, and peak demands for the period 2018 to 2039. Mr. Breuring began by explaining key electric delivery and demand variables, such as weather, the economy, and population demographics. 8 TR 1645-1646. He went on to explain his forecasting methodology for electric deliveries and peak demand, which included the use of statistical modeling, or a regression analysis. 8 TR 1646-1648. He explained that regression modeling is used to develop the electric deliveries and customer count forecast models based on weather and economic variables, and further explained how two statistical tests, adjusted coefficient of multiple determinations (" $R_a^2$ ") and Mean Absolute Percentage Error ("MAPE"), are used to evaluate how well the models fit the historical data, and also provide a good indication of how well the models will perform in the forecast period. 8 TR 1648-1650.

(i.) **Historical Electric Deliveries**

According to Mr. Breuring, in the past five years, weather-normalized electric deliveries decreased at a 0.3% Compound Annual Growth Rate (“CAGR”) from 2012 to 2017, with most of the observed loss occurring in the residential class (-0.5% for the same period), and the commercial class (-0.2%). 8 TR 1650. This was caused by a “nearly flat population growth in the electric service territory during this period.” 8 TR 1651. Industrial sales returned to pre-recession sales levels largely due to the polycrystalline manufacturing industry, and total industrial deliveries are expected to increase in the next two years, with the polycrystalline industry expecting to see flat to moderate growth over that period. 8 TR 1651-1652.

(ii.) **BAU Forecasted Electric Deliveries And Generation Requirements**

Mr. Breuring explained the near- and long-term delivery expectations in the Company’s BAU case as follows:

“Total electric deliveries are expected to increase at a marginal 0.3% in 2018, and remain relatively flat through the next five years (2018 to 2022) at a 0.05% CAGR. Projecting to the end of the Integrated Resource Planning (‘IRP’) forecasting period (2039), total deliveries are expected to grow at a modest 0.2% annually. The annual class-level results of the electric deliveries forecast process are shown in Exhibit A-71 (EMB-1).” 8 TR 1652.

The Company’s total generation requirements were based on the 2015 System Loss Study which demonstrated that the forecasted total electric deliveries are increased by a line loss factor of 7.45% to determine the Company’s total bundled generation requirements, shown on Exhibit A-74 (EMB-4). 8 TR 1653.

**(iii.) BAU Forecasted Peak Demand**

For the Company's expectations for growth in peak demand for the BAU case, the Company's used regression analysis based on the predicted level of electric deliveries. 8 TR 1656. As Mr. Breuring explained:

“Weather-normal peak demand grew at a 1.6% CAGR from 2003 to 2007, but reversed much of this trend during the 2007 to 2009 recession when weather-normal peak demand retracted by 4.3%. Looking forward, peak demand is expected to increase 0.3% per year from 2017 to 2039, the end of the IRP forecast period. The annual system-level results of the peak demand forecast is shown in Exhibit A-72 (EMB-2).” 8 TR 1656.

By developing hourly load profiles for the Smart Energy and EWR programs, the Company was able to identify the peak demand impacts of the Company's Smart Energy and EWR Programs. 8 TR 1658. Based on this process, it was determined that the Company's future Smart Energy programs reduce the peak demand forecast by approximately 101 MW in 2018, and increases to 525 MW by 2028 for the Company's direct control and Peak Time of Use (“TOU”) programs. 8 TR 1656. Further, the demand reductions are projected to stabilize at this 525 MW level for the rest of the IRP projection period (2039) because these programs are being implemented as part of the Company's Smart Energy infrastructure investments in which customers are provided technology and information to better manage their impact on the Company's system. 8 TR 1656-1657. Additionally, the EWR Program is projected to reduce peak demand by 465 MW in 2018 and the cumulative reductions produced by the EWR Program are expected to increase to 896 MW by the end of the IRP projection period (2039). 8 TR 1657.

**(iv.) Alternative Forecasted Deliveries And Demand Sensitivities**

In addition to the BAU, three sensitivities were developed off of the BAU, those include:

High Growth Sensitivity – Higher electric deliveries forecast due to accelerated economic growth of 1.5%. This sensitivity has the total Company electric deliveries increased by 1.5%

annually from 2018 to 2039, simulating unusual economic growth in the Company's electric service territory. 8 TR 1659. EWR projections are appropriately adjusted (increased savings) to reflect the electric delivery increase. 8 TR 1659.

Retail Open Access ("ROA") Shift Sensitivity – 50% of current electric ROA load is shifted to the Company's bundled, or full-service, load. This sensitivity assumes an immediate increase in the Company's full-service customers which, in turn, increases the EWR projections that are incorporated in the forecast. 8 TR 1660. The EWR impact due to this ROA shift does reduce the overall electric load from 2018 to 2039; however, the impact is minor: BAU growth rate (2018-2039 CAGR) is 0.21%; 50% ROA load shift growth rate is reduced to 0.17%. 8 TR 1660.

High EWR Savings Sensitivity – Assumes an EWR savings rate of 2.5%. This sensitivity assumes an increase in the annual EWR rate from 1.5% (BAU) to 2.5%. 8 TR 1660.

Exhibit A-73 (EMB-3) demonstrates the electric peak demands results for the Company's bundled load from 2018 to 2039. The CAGR for 2018 through 2039 shows the long-term impacts of the sensitivities compared to the BAU forecast. 8 TR 1660.

#### **h. Fuel Assumptions**

Company witness Brian D. Gallaway, Executive Director of Fossil Fuel Supply, detailed the fuel assumptions utilized in the development of the Company's IRP. 8 TR 1670-1686. Mr. Gallaway presented testimony addressing the Company's current fuel procurement and supply arrangements for the Company's existing generating facilities. Mr. Gallaway also provided the commodity pricing developed for the scenarios and sensitivities modeled by the Company and the fuel costs used in the IRP to evaluate options to meet Consumers Energy's projected capacity need beginning in 2019 – 2039.

The Company's utilizes Central Appalachia ("CAPP") bituminous coal and Powder River Basin ("PRB") sub-bituminous coal at the Company's coal-fired generating facilities, Karn Units 1 and 2 and Campbell Units 1, 2, and 3, in a manner which minimizes production costs and ensures compliance with regulatory requirements. 8 TR 1671-1672. The Company also manages a portfolio of multi-year, annual, quarterly, and sometimes monthly coal purchase contracts and coal transportation contracts with the various rail and vessel carriers of bulk commodities to the generating facilities. The Company's fuel procurement processes for its oil and natural gas fired generating units are plant dependent. 8 TR 1672-1673. Karn Units 3 and 4, the Zeeland Plant, the Jackson Plant, and the Company's peaking generating units are served with third-party owned pipelines and the distribution systems of Consumers Energy's natural gas utility and DTE Gas Company. Furthermore, oil burned at Karn Units 1 and 2 and the Campbell CT are purchased from the spot market when market prices are favorable.

With respect to the fuel costs used in the development of the IRP, Mr. Gallaway explained that the Company utilized a BAU natural gas price forecast. 8 TR 1674-1675. Consistent with the Commission's direction in Case No. U-18418, this forecast was based on the EIA January 2017 natural gas Henry Hub forecast found in the 2017 EIA AEO, Table 13 reference cases, for 2017 through 2040.<sup>6</sup> However, the Company made certain modifications to this forecast to recognize variations in gas prices that typically occur on a monthly basis during the year. Exhibit A-76 (BDG-2) shows the BAU forecast for 2017 through 2040.

Mr. Gallaway also explained that the Company developed low sensitivity and high sensitivity natural gas price forecasts in the development of the IRP. 8 TR 1675. Mr. Gallaway explained the low sensitivity forecast as follows:

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<sup>6</sup> The Henry Hub is a point on the natural gas system located in Erath, Louisiana, used as a pricing point for natural gas futures contracts traded on the New York Mercantile Exchange ("NYMEX"). 8 TR 1674.

“The low sensitivity case is the same Henry Hub natural gas price nominal forecast used in the Company’s internal studies as well as its PSCR filings. The Company acquired three long-term natural gas price forecasts and one short-term natural gas price forecast to develop a composite Henry Hub natural gas price forecast for 2017 through 2040. The long-term 2023 through 2040 natural gas price forecasts acquired include IHS Markit (‘is’) February 2017 forecast; the EIA January 2017 AEO; and Energy Ventures Analysis, Inc.’s (‘EVA’) August 2017 forecast. The near-term 2017 through 2022 natural gas price forecast was acquired from the NYMEX on August 29, 2017. The Consumers Energy annual Henry Hub natural gas composite price forecast used in the IRP is the average of the monthly values for each respective year of the NYMEX future prices for the near term (2017 through 2022) and an average incremental increase of the three long-term price forecasts applied to the years following the five-year futures contracts traded on the NYMEX for the long term (2023 through 2040).” 8 TR 1675.

Exhibit A-78 (BDG-4) shows the three third-party forecasts and the resulting annual composite forecast derived from the third-party forecasts. This low sensitivity forecast, with seasonality applied, is shown in Exhibit A-76 (BDG-2).

Mr. Gallaway explained that the Company’s high sensitivity forecast based on the BAU forecast and a 200% sensitivity curve, as directed by the Commission in Case No. U-18418. 8 TR 1677. The slope of the curve was calculated using the 200% December 2040 BAU forecast value minus the September 2017 BAU forecast value divided by the number of years during the period of 2017 through 2040. The forecast also includes seasonality. Exhibit A-76 (BDG-2) shows the high sensitivity forecast for 2017 through 2040.

Based on the above forecasts, the Company developed a delivered natural gas cost to each of the Company’s natural gas generating plants and a potentially new Company-owned natural gas generating plant. For the Karn Units 3 and 4, the Zeeland Plant, and the Jackson Plant, the Company considered the natural gas forecasts in relation to the costs for the current transportation contracts for these units. 8 TR 1677-1678. For any new

Company-owned natural gas plant, the Company assumed that the plant would be based connected to the Company's gas transmission system with the same firm gas transportation structure that would have existed for the proposed Thetford Generating Plant ("Thetford") in 2013, had that plant been built. 8 TR 1878-1879.

With respect to the BAU oil price forecast used in the IRP, the Company used a similar approach to what was used in the development of the natural gas price forecast. 8 TR 1680-1681. This was described in detail by Mr. Gallaway:

"Consumers Energy acquired three long-term crude oil price forecasts and one short-term crude oil price forecast and used them to develop a composite crude oil price forecast for 2018 through 2040. The long-term crude oil price forecasts acquired include IHS's December 2016 forecast; EIA's January 2017 AEO forecast; and EVA's August 2017 forecast. The short-term crude oil price forecast was acquired from NYMEX. Consumers Energy's annual crude oil composite price forecast is the average of the monthly values for each respective year of the NYMEX future prices for the near term (2017 through 2022), a simple average of the three long-term price forecasts for the long term (2025 through 2040), and a linear blending between the near-term and long-term forecasts to develop the mid-term period (2023 through 2024)." 8 TR 1680.

Exhibit A-80 (BDG-6) shows the three referenced third-party forecasts as well as the Company's annual crude oil composite forecast derived from the third party forecasts. The transportation cost of oil to the Company's existing generating plants was also developed and is included in the forecasted oil price in Exhibit A-80 (BDG-6).

Finally, Mr. Gallaway explained the BAU coal forecast used in the development of the IRP for the Company's existing coal-fired generating units. Specifically, the Company utilized a composite mine mouth price forecast which was developed using: (i) the Company's knowledge of actual market activity for the near term (2017 through 2019); (ii) a simple average of the IHS Markit, EIA, Energy Ventures Analysis, Inc., and JD Energy long-term forecasts for the long

term (2022 through 2040); and (iii) linear blending between the short term and long-term forecasts to develop a mid-term period (2020 through 2021). 8 TR 1681. Exhibit A-81 (BDG-7) and Exhibit A-82 (BDG-8) show the four third-party forecasts as well as the Company's annual composite forecast derived from the third-party forecasts for CAPP bituminous coal and PRB sub-bituminous coal, respectively.

In addition, Mr. Gallaway explained how the above coal forecasts were used to develop the delivered coal cost to each of the Company's coal-fired generating plants as follows:

“Coal transportation costs (rail and vessel, including railcar costs) were projected specific to each existing Consumers Energy coal fired generating plant. These transportation costs were added to the mine mouth composite price forecasts to produce delivered coal price forecasts for each existing Consumers Energy coal fired generating plant. The transportation costs were developed using existing Consumers Energy transportation contract pricing and expected pricing in the near term. The Near-term transportation costs were escalated at the quarterly trend of the All Inclusive Index – Less Fuel (‘AII-LF’) and a monthly mileage-based fuel surcharge was added to achieve long-term transportation costs through the Planning Period. The AII-LF is a rail industry price index that measures changes in the price level of inputs to railroad operations without the influence of fuel costs. The AII-LF is published quarterly by the American Association of Railroads and approved by the Surface Transportation Board (‘STB’).” 8 TR 1682.

Exhibits A-83 (BDG-9) through A-84 (BDG-10) show the delivered coal price forecasts used in the IRP analysis for the Company's existing coal fired generating units.

**i. Production And ITCs**

Tax credits are potentially available for certain renewable energy resources. Company witness Carolee K. Smith, Director of Tax Planning and Tax Counsel, provided testimony regarding potential available tax credits. The common tax credits available for purposes of the IRP are the PTC and the ITC.

The PTC is a federal income tax credit enacted to incentivize the production of energy from renewable energy resources. It is set forth in Section 45 of the Internal Revenue Code, 26 USC 45. The PTC for any taxable year is an amount equal to 1.5¢ (adjusted for inflation) multiplied by the kwh of electricity produced by the taxpayer from qualified energy resources. 8 TR 1731-1732. The following energy resources qualify for the PTC: (i) wind; (ii) certain biomass; (iii) geothermal; (iv) small irrigation; (v) municipal solid waste; (vi) qualified hydropower production; (vii) marine; and (viii) hydrokinetic energy. 8 TR 1732. The Protecting Americans from Tax Hikes Act of 2015 (“PATH Act”) provides for the phase out of the PTCs; however, future wind energy parks either constructed or acquired by the Company may still qualify for a period of time. Wind projects for which construction has started before January 1, 2017 will receive 100% of the PTC. Wind projects for which construction starts after January 1, 2017, but before January 1, 2020, still qualify for the PTC but at a reduced rate. 8 TR 1732. The PTC for wind projects decreases by 20% each year for wind projects starting construction in a particular subsequent year until the available PTC reaches only 40% for wind projects that start construction before January 1, 2020. 8 TR 1733. Wind projects that start construction after December 2019 do not qualify for PTC. The proposed solar energy installations would not qualify for the PTC. 8 TR 1732. The Company receives the PTC for the 10-year period beginning on the date the facility was originally placed in service, and customers realize the benefit of the PTC at the same time the Company does.

The ITC is a federal income tax credit enacted to incentivize investment in energy property. It is set forth at Section 48 of the Internal Revenue Code, 26 USC 48. The ITC is equal to 30% of the basis of energy property in the year such property is placed in service. 8 TR 1733. For purposes of the ITC, energy property is solar energy equipment, qualified fuel cell

property or qualified microturbine property, combined heat and solar system property, qualified small energy wind property, and geothermal energy equipment. 8 TR 1733. Like the PTCs, the PATH Act provides for the phase-out of the ITC. Wind projects for which construction has started before January 1, 2017 will receive 100% of the ITC allowed (i.e., the full 30% ITC). Wind projects for which construction starts after January 1, 2017, but before January 1, 2020, still qualify for the ITC but at a reduced rate. 8 TR 1734. The ITC decreases by 20% each year for wind projects starting construction in a particular subsequent year until the available ITC reaches only 40% for wind projects that start construction before January 1, 2020. 8 TR 1734.

Solar projects also qualify for the ITC. Solar projects for which construction has started before January 1, 2020 will receive 100% of the ITC allowed (i.e., the full 30% ITC). 8 TR 1735. Solar projects for which construction starts after January 1, 2020, but before January 1, 2024, still qualify for the ITC but at a reduced rate. The ITC decreases to 26% for solar projects starting construction after December 31, 2019 but before January 1, 2021, and 22% for solar projects starting construction after December 31, 2020 but before January 1, 2022. Solar projects that start construction before January 1, 2022, but that are not placed in service before January 1, 2024, qualify for ITC of 10%, as do solar projects that start construction after December 2021. 8 TR 1734. The Company receives the benefit of the ITC in the year the energy property is placed in service and these benefits are passed to customers over the life of the asset.

**j. DR Assumptions And Potential Studies**

Company witness Patrick C. Ennis, Consumers Energy's Executive Director of Industrial Products, described the Company's existing and proposed DR portfolio, and the assumptions associated with the DR programs within the IRP. 8 TR 1513. The intent of the DR portfolio is to collectively reduce peak load, thereby relieving stress on the electric system in a more

cost-effective manner than purchasing capacity from the market or building additional generation resources to meet peak demand. 8 TR 1515. Mr. Ennis sponsored the Company’s 2017 DR Annual Report, Exhibit A-62 (PCE-3), which provided an overview of the 2017 DR programs, activities, and achievements. 8 TR 1515. He described in detail both the Business DR Program (8 TR 1515-1518) and the Residential DR Program (8 TR 1518-1520), including the changes that the Company proposed in its pending electric rate case, Case No. U-20134 (8 TR 1520-1522).

Mr. Ennis also sponsored Exhibit A-60 (PCE-1) which showed that under the PCA, the level of DR would increase from 287 MW in 2018 to 1,250 MW in 2030 and then remain at that level through 2040, as summarized below:

<u>Description</u>		<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2030</u>	<u>2040</u>
DPP	MW	20	24	27	30	131	131
DLA	MW	44	62	79	94	104	104
C&I DR	MW	120	180	240	270	290	290
Rate GI	MW	137	137	137	137	137	137
Rate EIP	MW	48	48	48	48	48	48
<b>Total Existing Planned DR ("base")</b>	<b>MW</b>	<b>369</b>	<b>451</b>	<b>531</b>	<b>580</b>	<b>711</b>	<b>711</b>
AEG Potential (incremental)	MW	0	0	0	27	539	539
<b>Total DR in Proposed Course of Action</b>	<b>MW</b>	<b>369</b>	<b>451</b>	<b>531</b>	<b>607</b>	<b>1,250</b>	<b>1,250</b>

8 TR 1513-1514, 1522.

The planned increases in each of the base programs are based on assumptions regarding the number of customers currently enrolled, current and planned marketing efforts to add customers, the additional DR potential for each new customer, assumed cost of adding customers and MW, and the current average MW per customer. The PCA also included incremental DR that the Company believes it can reasonably achieve based on the Applied Energy Group (“AEG”) September 29, 2017 State of Michigan DR Potential Study (“AEG Statewide DR Study”). 8 TR 1522-1523.

Robert L. Fratto, Managing Director with GDS Associates (“GDS”), an expert witness in the areas of energy efficiency, DR, and renewable energy, testified that the amount of DR included in the PCA is reasonable. Mr. Fratto sponsored GDS’ estimate of DR potential for Consumers Energy that was the basis for the DR forecast that the Company included in its PCA. 8 TR 1547. He explained that GDS, using its own methodology, allocated to the Company’s service area, a portion of the DR potential identified in the AEG Statewide DR Study (8 TR 1549-1557). The allocation was needed because the AEG Statewide DR Study was an overall statewide study of DR potential that did not present utility-specific results. Mr. Fratto therefore used the AEG Statewide DR Study to develop an estimate of Consumers Energy’s portion of that statewide potential. 8 TR 1549-1550. Mr. Fratto testified that the amount of DR included in the PCA was reasonable based on: (i) the range of DR potential estimates represented by the low and high cases for the realistic achievable potential based on his allocation of the DR potential identified in the AEG Statewide DR Study; and (ii) his review, and that of his colleagues, of other recent DR potential studies. 8 TR 1564-1566.

**k. EWR Assumptions And Potential Studies**

The Company first began offering EWR programs in 2009, and has refined its programs through the years to increase the amount of energy savings from 0.3% in 2009 to 1.0% in 2012 through 2016. 8 TR 1580. In 2017, Consumers Energy increased the level of energy savings from 1.0% per year to 1.5% per year. 8 TR 1580. The cost to acquire energy savings from the Company’s 2018 through 2021 EWR Plan was used to project the anticipated cost to deliver energy savings of 1.5% per year. 8 TR 1583. The Company then used the energy efficiency supply curves developed by GDS to forecast the incremental investments necessary to deliver energy savings of 2.0% per year in 2021 through 2029, and 2.25% per year in 2030 through 2040. 8 TR 1583-1584; Exhibit A-63 (TAY-1).

The Company's base case assumes 1.5% EWR savings growth in all years of the planning period. 6 TR 465. In order to realize avoided energy benefits and capacity value of expanded EWR, the Company selected the expansion of EWR to 2.0% beginning in 2021 as the resource to offer into the Strategist modeling. 6 TR 465. This provides 212 MW of peak demand reduction and approximately 1.5 million MWh of lower generation requirements by the year 2030. 6 TR 465. Expanded EWR was selected to begin in 2020 (to achieve 2.0% savings by 2021), regardless of the first year of portfolio optimization, in order to deliver higher levels of peak demand reductions to fill significant capacity shortfalls. 6 TR 465. Consumers Energy determined to expand EWR beginning in 2020 because: (i) the Levelized Cost of Energy ("LCOE") for EWR is the second lowest-cost resource when compared with all other resource options; (ii) EWR was initially offered to the model as its own portfolio and reduces Net Present Value ("NPV") costs in all but two retirement base case scenarios; and (iii) Strategist would not select EWR in 2020 if no capacity need exists in that year. 6 TR 465-466.

Company witness Richard F. Spellman, Senior Vice President of GDS, explained the projected potential electricity savings and program implementation costs for Consumers Energy's service territory under the various scenarios examined in the Michigan Lower Peninsula Electric Energy Efficiency Potential Study ("Statewide Study"). 8 TR 1595-1596. The Statewide Study BAU case indicated an achievable potential for cumulative annual electricity savings, based on screening with the Utility System Resource Cost Test, for the Consumers Energy and DTE Energy Electric Company service areas overall as 14.4% of sales by 2026, and 20.4% of sales by 2036. 8 TR 1601. The EWR potential identified for just the Consumers Energy service area in the Statewide Study BAU case is 2.3% per year for the 2017 to 2036 period. 8 TR 1604. After applying net-to-gross ratios to the estimates of electric EWR

potential based on gross savings in order to account for free-ridership and spillover, the Consumers Energy electric EWR potential is 2.0% per year based on net savings. 8 TR 1614. GDS concluded that “on average, 2% of annual MWh sales for the Consumers Energy service area is a reasonable BAU estimate for the potential savings for cost effective EWR measures over the next 20 years.” 8 TR 1614-1615.

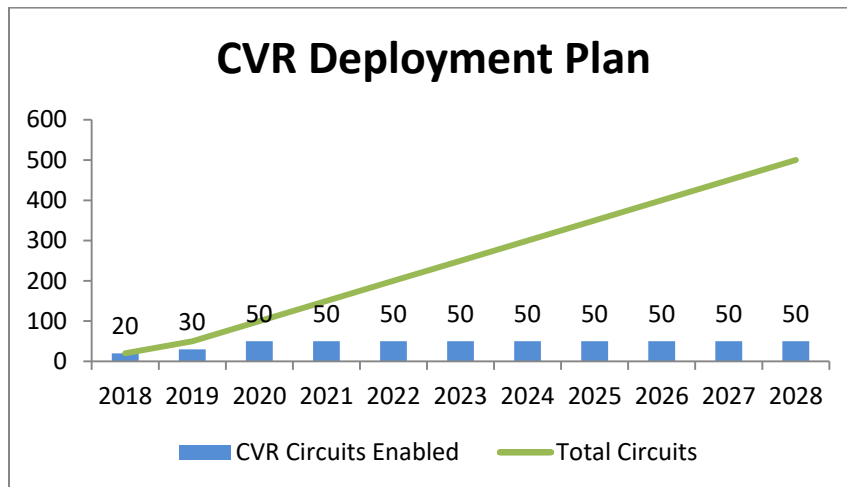
### **I. CVR Assumptions**

Company witness Mark A. Ortiz, Consumers Energy’s Grid Modernization Program Lead, testified in support of the Company’s CVR Program. 8 TR 1618. The primary objective of the CVR Program is to optimize service-point, or customer meter, voltages to reduce energy demand and the associated carbon footprint of the Company’s system, without requiring active participation or behind the meter investment by customers. 8 TR 1620. Mr. Ortiz explained that CVR is a proven set of technologies that reduces the delivery voltage along electric circuits, which in turn reduces the amount of electric load that must 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. 8 TR 1621.

The primary and direct benefit of CVR is the reduction in the amount of energy consumption on the electric system. 8 TR 1633. The system peak demand MW reduction results in reduced generation capacity costs (avoided or deferred, new build investment, or purchased) while the MWh reduction in energy results in avoided supply costs (generation or wholesale market purchases) and reduced line losses. The peak demand and energy reduction benefits are explicitly captured in the IRP modeling and economic analysis. *Id.* Mr. Ortiz sponsored

Exhibit A-70 (MAO-4), which presented the forecasted annual peak demand and energy reductions from the deployment of the CVR Program and included in the Company’s PCA. The exhibit showed an expected reduction to annual electric demand by 111 MW and 256,355 MWh by 2028.

Mr. Ortiz provided the Company’s plan for CVR deployment in the figure below (8 TR 1626):



As shown above, the Company would begin deployment on up to 20 circuits beginning in 2018, would ramp up to 50 circuits in 2020, and after that point would remain at 50 circuits per year through 2028, for a total of 500 circuits over the 11-year period. 8 TR 1625.

The Company expects that, by 2028, it will have deployed CVR everywhere that makes economic sense. As more circuits became financially viable for CVR in the future, the Company would continue to deploy the technology as necessary. The plan was created based on existing deployments of devices that can support CVR and includes a ramp-up period to better understand CVR operation. While Consumers Energy could possibly speed up or slow down deployment, the Company believes that this proposed plan makes the most financial and reasonable sense, given the initial learning curve and amount of funding required. 8 TR 1625-1626.

**m. Environmental Regulations**

In developing its IRP, the Company also took into consideration the environmental regulations with which the Company's electric generating fleet must comply, the cost of compliance with those regulations, as well as the timing and justification for the investments made to ensure environmental regulatory compliance and the best plan for Michigan. 8 TR 1740. Company witness Heather A. Breining addressed these issues, and began by discussing relevant and applicable air quality regulations, water quality regulations, and waste regulations in her direct testimony.

**(i.) Air Quality**

Ms. Breining outlined and discussed the following applicable air quality regulations with which the Company must comply. Those include:

Cross State Air Pollution Rule: Governs the emissions of sulfur dioxide and nitrogen oxides from 16 fossil-fueled Electric Generating Units ("EGUs") through the use of an allowance-based cap and trade program, except that it restricts interstate trading for use only for addressing small changes in year-to-year emissions variability. 8 TR 1741-1742.

Mercury and Air Toxics Standards ("MATS"): A federal rule that regulates emissions of mercury, acid gasses, certain metals, and organic constituents via emission rate limits or the use of work practices for coal and oil-fired EGUs. 8 TR 1742.

Michigan Mercury Rule (“MMR”): Much like the federal MATS, the MMR was designed to regulate mercury air emissions in the state of Michigan. The MMR requires existing coal-fired EGUs to choose one of three methods to comply with the emission limits set forth in the MMR, and requires any new EGU to utilize the best available control technology. 8 TR 1743.

Clean Power Plan: Designed to regulate greenhouse gas emissions under Sections 111(d) for the existing sources, and 111(b) for new and/or modified sources of the Clean Air Act, which, in the Environmental Protection Agency’s (“EPA”) view, was meant to regulate the carbon emissions from America’s fleet of fossil-fuel power plants. Note: legal proceedings have been initiated challenging the final Section 111(d) rule for existing EGUs, and a resulting stay of the Clean Power Plan has been granted pending judicial review. 8 TR 1743-1744.

**(ii.) Water Quality**

Ms. Breining also outlined and discussed the following applicable water quality regulations with which the Company must comply. Those include:

EPA’s Rule Regarding the CWA 316(b): 316(b) established new standards for Cooling Water Intake Structures (“CWIS”) at existing facilities. It requires existing power generation facilities with a design intake flow greater than two mgd from waters of the United States for cooling, to reduce impingement and entrainment of fish and other aquatic organisms at CWIS. Additionally, any facility subject to the 316(b) with actual flows in excess of 125 mgd must provide an entrainment study with its National Pollutant Discharge System permit application. 316(b) establishes national requirements which apply to the location, design, construction, and capacity of CWIS, and requires the use of Best Technology Available (“BTA”) for minimizing adverse environmental impact. 8 TR 1746-1751.

EPA's Effluent Limitation Guidelines: EPA's final Effluent Limitations Guidelines ("ELG") rule for the Steam Electric Power Generating Point Source Category (referred to as SEEG) establishes effluent limitations (i.e., regulatory restriction on the concentrations of chemicals a facility may discharge) based on BTA for existing sources. The final ELG rule for SEEG excludes oil-fired generation units and units with a nameplate capacity of 50 MW or less. The final ELG rule for SEEG also establishes New Source Performance Standards and Pretreatment Standards for Existing and New Sources that discharge to Publically Owned Treatment Works and applies to effluent limitations and pretreatment standards for existing sources for flue gas desulfurization wastewater bottom ash transport water, fly ash transport water, flue gas mercury control wastewater, and gasification wastewater. 8 TR 1751-1754.

EPA's Final Rule regarding Disposal of Coal Combustion Residuals ("CCRs") from Electric ("CCR Final Rules"): The EPA's CCR Final Rules finalized national regulations to provide a comprehensive set of requirements for the safe disposal of CCRs, commonly known as coal ash, from coal-fired power plants. The CCR Final Rules regulates infrastructure also affected by the ELG rule for SEEG, specifically bottom ash ponds/impoundments. For example, if unlined impoundments cannot meet certain criteria, facilities are required to cease using them in 2018. 8 TR 1754-1755.

### **(iii.) Waste Quality**

Finally, Ms. Breining outlined and discussed the following applicable waste quality regulations with which the Company must comply. Those include:

Resource Conservation and Recovery Act ("RCRA"): The CCR Final Rules establish technical requirements for CCR landfills and surface impoundments under Subtitle D of the RCRA, the nation's primary law for regulating solid waste. The new rules establish minimum

national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. 8 TR 1760.

Water Infrastructure Improvements for the Nation Act: This law provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Final Rules through the RCRA Citizen Suit Authority. States may elect to submit a CCR permit program to the EPA for approval, and the EPA must either approve the permit program or enforce its own. 8 TR 1760-1761.

As Ms. Breining discussed, the Company has plans for implementation and compliance with all of these regulations. 8 TR 1741-1763.

When developing the IRP, in addition to the scenarios and sensitivities included in the modeling of the IRP (and as summarized in Company witness Walz's Exhibit A-10 (STW-1)), there were three additional scenarios added to the Company's IRP. 8 TR 1765. As Ms. Breining explained, "[t]he majority of input assumptions matched those of the BAU, Emerging Technologies, and Environmental Policy scenarios, with one single input variable modified, which was the assumed cost of natural gas." 8 TR 1765. Thus, the major input assumptions are summarized in Company witness Walz's Exhibit A-11 (STW-2), and are as follows:

“BAU AEO – BAU, built on required gas prices from the Energy Information Administration's ('EIA') 2017 Annual Energy Outlook ('AEO') reference case;

“EP AEO – Environmental Policy, built on required gas prices from the EIA's 2017 AEO reference case;

“ET AEO – Emerging Technologies, built on required gas prices from the EIA's 2017 AEO reference case;

“BAUCE – BAU, built on Consumers Energy's gas price projections;

“EP CE – Environmental Policy, built on Consumers Energy’s gas price projections; and

“ET CE – Emerging Technologies, built on Consumers Energy’s gas price projections.” 8 TR 1766.

A comparison of total projected carbon dioxide (“CO<sub>2</sub>”) emissions under each scenario and sensitivity analyzed, including quantifying the CO<sub>2</sub> emissions projected in each sensitivity as a percentage of the CO<sub>2</sub> emissions presented in the BAU case, can be found on Exhibit A-95 (HAB-6).

**n. Financial Assumptions**

Company witness Heidi J. Myers supported the fixed charge rate used in the IRP modeling. She explained that the fixed rate charge “provides the amount-per-dollar of original investment outlay which an investment must generate each and every year over the course of its anticipated average service life in order to meet a specified annual rate of return given a set of assumptions regarding cost of removal, state income tax, federal income tax, and tax life.” 7 TR 1033. Additionally, the net average Company property tax and insurance annual rates are used in the computation. 7 TR 1033.

Ms. Myers further explained that the fixed charge rate was one of the assumptions used by Company witness Walz in her IRP modeling. 7 TR 1033. A 35% federal income tax rate was assumed in the fixed charge rate based on the timing of the modeling, and a sensitivity was subsequently run using a fixed charge rate that included a 21% federal income tax rate, which is the current federal income tax rate, effective as of January 1, 2018. 7 TR 1033.

**o. Assumptions For Existing Capacity And Energy Contracts**

Company witness Keith G. Troyer, Senior Engineer II in the Electric Contract Strategies Section, provided an overview of the key input assumptions in the IRP related to the Company’s

PPAs. As of the beginning of 2018, the Company has 55 long-term PPAs in place representing 2,947 MW of contract capacity with independent power producers for the purchase of energy, capacity, and/or RECs. Of the 55 PPAs, 34 PPAs are for the purchase of energy and capacity, 6 PPAs provide renewable energy under the Renewable Resource Program (a/k/a Green Generation Program), 12 PPAs provide renewable energy under the RE Plan, and 3 PPAs are in place under the Experimental Advanced Renewable Program (“EARP”)-Anaerobic Digestion Program. Additionally, the Company has executed six contracts for the purchase of energy and has 379 contracts in place for the purchase of solar energy, capacity, and RECs as part of the EARP-Solar Program. 8 TR 1239. Exhibit A-39 (KGT-1) shows a list of the contracts that the Company currently has, or expects to have, in place during the IRP study period.

The Company’s IRP modeling includes certain assumptions regarding the PPAs in place. The expected production and associated expense from the PPAs is included as part of the Company’s supply portfolio through the expected termination of the agreements. 8 TR 1240. The Company forecasts that at the conclusion of their existing PPAs, counterparties with renewable generators, who are QFs that have expiring contracts for energy and capacity or as part of the Renewable Resource Program, up to 20 MW in size, will sign new PURPA contracts with the Company. 8 TR 1240.

Additionally, the Company has contracted to purchase 20 ZRCs through Planning Year 2020 as part of the reverse capacity auction that was conducted on September 23, 2014. These transactions were approved in the Commission’s January 27, 2015 Order in Case No. U-17725. 8 TR 1240. The Company has also included 150 MW of PURPA contracts as directed in the Commission’s February 22, 2018 Order in Case No. U-18090. 8 TR 1240. In addition to the 150 MW of new PURPA contracts discussed above, the Company anticipates that the Filer City

facility will add approximately 157 ZRCs to the Company's supply portfolio beginning June 1, 2020.<sup>7</sup> 8 TR 1242.

As shown in Exhibit A-39 (KGT-1), the Company's IRP modeling assumes an extension of the MCV PPA. The Amended and Restated PPA with MCV was approved in the Commission's June 10, 2008 Order in Case No. U-15320. 8 TR 1242. Under the terms of the contract, the Company may unilaterally extend the MCV contract an additional five years upon proper notice as outlined within this provision of the agreement.

**p. Transmission Assumptions**

When the Company engaged METC in its IRP process, based on six scenarios for generation additions and retirements provided by the Company, METC provided the Company with an analysis of those six scenarios. 6 TR 673. METC also provided the Company with possible system improvements and advanced technologies that could be deployed to increase Michigan's Capacity Import Limit ("CIL"). 6 TR 673. METC's analysis is provided in Exhibit A-97 (DAL-2). METC's analysis included two retirement options (retirement of either Campbell Unit 2 or Karn Units 1 and 2), and each option was coupled with the addition of: (i) adjusted MISO queue generation; (ii) a single 1,100 MW unit at Thetford; or (iii) four 275 MW additions at four sites (Washtenaw, Gratiot, Midland, and Isabella) across lower Michigan. 6 TR 674. While METC was completing its study, the Company's internal IRP analyses, which contained alternate scenarios to those used by METC, were simultaneously

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<sup>7</sup> On August 3, 2018, FERC denied Filer City's application for recertification of the Filer City cogeneration facility as an existing cogeneration QF pursuant to PURPA. Article 1 of Amendment No. 2 to the Company's PPA with Filer City, requires that FERC approve the recertification of the converted Filer City cogeneration facility as a QF. Since this condition was not met, Amendment No. 2 to the Company's PPA with Filer City has been rendered void ab initio. This means that the additional ZRCs will not be available from Filer City. 7 TR 943. If everything were to develop as planned in the PCA, absent the additional capacity that would have been provided by Amendment No. 2 to the Filer City PPA, the Company would now experience a small shortfall in 2031 and 2032. The small shortfall in 2031 and 2032 could never materialize as a result of load forecast inaccuracy or changes in performance of existing generation or demand-side programs. 7 TR 943; see Exhibit A-99 (TPC-7).

performed. 6 TR 674. Because of the simultaneous nature of the analyses, the Company's IRP analyses, which contained alternate scenarios to those used by METC, were used to develop its PCA in its IRP. 6 TR 674. Thus, the scenarios utilized by METC, which were provided by the Company early in the IRP evaluation process and were based on possible generation fleet changes, did not align with those set forth in the Company's internal evaluation of possible scenarios and were not utilized to arrive at the Company's PCA. 6 TR 674.

While the scenarios utilized by METC do not align with the Company's IRP scenarios, the Company found the results of METC's analysis informative. As Mr. Lynd explained:

"The scenarios studied by METC provide a detailed look at the impacts of generation unit retirement, coupled with the addition of generation at various sites. These results demonstrate that transmission network upgrades are likely necessary on the Lower Michigan transmission network to accommodate a changing generation fleet and also demonstrate the level of investment that may be necessary." 6 TR 674.

In fact, based on the summary results provided by METC in its transmission evaluation, as augmented by the discussion at the meetings, Mr. Lynd concluded that the cost ranges provided for by METC based on the six scenarios used by METC were reasonable. 6 TR 675. Those levels of investment included: (i) a minimum cost of transmission network upgrades for four of the scenarios studied of between \$20 million and \$40 million; and (ii) a minimum cost of transmission upgrades for two of the scenarios studied of between \$50 million and \$75 million (for transmission network upgrades to accommodate the generation specifically connected to the 138 kV system). 6 TR 675.

When running scenarios for purposes of development of the Company's IRP, one of the scenarios tested determined that generation capacity was required. 6 TR 675. As a result, a transmission network upgrade cost component of \$54,000/MW of generation capacity was used in the IRP economic analysis performed by the Company for all generation technologies located

in Michigan. 6 TR 675. This transmission upgrade cost assumption, as explained by Mr. Lynd, was determined as follows:

“The network upgrade cost is based on a survey of 11 recently executed Generator Interconnection Agreements (‘GIA’) with either METC or ITCT, as reported in the generation interconnection queue on the MISO website. [Footnote omitted]. The data was obtained from the executed GIAs posted in the FERC’s eDocket [footnote omitted] system. Network upgrade costs across these GIAs [footnote omitted] ranged from \$1,300/MW to \$179,000/MW. These costs include all transmission owner expenses to accommodate the interconnection of the generation, including rights-of-way, permits, and other costs. The weighted average of these network upgrade costs was \$54,000/MW.” 6 TR 675-676.

Additionally, as Mr. Lynd explained, METC’s analysis determined transmission upgrade costs following the addition of 1,100 MW of new generation simultaneous with a generation retirement of 384 or 576 MW. This resulted in “[t]he ratio of investment compared to the incremental MW additions across all METC-studied scenarios ranges from \$28,000/MW to \$143,000/MW.” 6 TR 676.

While the MISO Generator Interconnection Agreements (“GIA”) and METC analyses provided a range of network upgrade costs, Mr. Lynd indicated that a definitive cost cannot be provided because network upgrade costs vary by project. As Mr. Lynd further explained:

“Installed generation capacity (MW), connection voltage, and location on the transmission grid are among the variables that influence upgrade costs. Network upgrade costs for a specific transmission-connected project can only be determined through a MISO generator interconnection study for new generation, or an Attachment Y study for retiring units.” 6 TR 676.

Mr. Lynd, however, testified that: “[t]he transmission network upgrade cost component assumption of \$54,000/MW reflects a typical cost seen by other large generation projects at sites across Lower Michigan [and] is within the range of network upgrade costs determined in METC’s study.” 6 TR 676.

**q. Capacity Import And Export Limit Assumptions**

The Company also made CIL and Capacity Export Limit (“CEL”) assumption in the preparation of the Company’s IRP – utilizing a CIL of 3,316 MW and a CEL of 2,996 MW. 6 TR 677. These amounts were derived from public reports from MISO. 6 TR 677. Although MISO analyzed the transmission import and export capabilities for the MISO Local Resource Zone 7 (“LRZ7”) (which essentially encompasses the entire geographic area of the Lower Peninsula of Michigan) for other years, Mr. Lynd explained that the Company selected the MISO year 2021 values for use in the preparation of its IRP, because it was the only year that was also used in the Company’s IRP evaluation. 6 TR 677. Since the start of the Company’s IRP evaluation process, however, MISO published updated CIL and CEL values, determining the CIL and CEL for 2021 to be 3,143 MW and 1,659 MW, respectively. 6 TR 677

As explained by Mr. Lynd in his direct testimony, CEL represents the maximum amount of power that can be exported to another zone and is only important if there is a surplus of local capacity in the zone. 6 TR 678. He concluded that: “[t]he Company’s PCA does not contemplate constructing a surplus of capacity such that exports in excess of the CEL are needed.” 6 TR 678. CIL is a measure of the transmission system’s ability to transport power from one zone to another. 6 TR 679. An increase in the CIL is only required if there is a need or desire to import resources in excess of the CIL for LRZ7. 6 TR 678. Since recent MISO Planning Reserve Auctions demonstrate that there is an abundance of CIL (approximately 3,500 MW of unused import capacity), and for other additional reasons further discussed below, Mr. Lynd explained that the Company’s PCA does not require import capacity at or near the CIL, and it would, therefore, “be imprudent to make investments to increase the CIL.” 6 TR 678-680

## **2. Modeling Process**

Consumers Energy's modeling process used in developing the IRP was based on the requirements in MCL 460.6t and in the MIRPP, which the Commission adopted in Case No. U-18418. 6 TR 430. After developing assumptions for capacity position, identifying viable resource options, and developing production cost models, Consumers Energy: (i) constructed portfolios for evaluation; (ii) performed portfolio optimization and production cost simulation analysis; (iii) evaluated portfolios using quantitative and qualitative measures; and (iv) evaluated portfolios through scenario and sensitivity analysis. 6 TR 431. The Company ultimately used this rigorous and comprehensive modeling process to identify the key elements of the PCA. 6 TR 426.

### **a. Modeling Of Scenarios And Sensitivities**

The MIRPP required the Company to include certain scenarios and sensitivities in the Company's IRP modeling. 6 TR 427. The Company evaluated three base case scenarios: (i) a BAU scenario, which is consistent with many of the Company's major assumptions, including customer demand, EWR, DR, cost of capital for new resources, and environmental regulations; (ii) an ET scenario, which assumes advancements in technologies and economies of scale result in greater potential for DR, EWR, and other ET; and (iii) an EP scenario, which targets carbon reduction of 30% from 2005 to 2030. 6 TR 427. The Company was required to include 13 sensitivities on the various scenarios to examine the impact resulting from changes to certain assumptions. 6 TR 427. The major assumptions associated with the required scenarios and sensitivities are indicated in Exhibit A-10 (STW-1).

Consumers Energy included three additional scenarios to its IRP modeling that were not required by the MIRPP. 6 TR 428. The majority of the input assumptions for these three

additional scenarios matched those of the BAU, ET, and EP scenarios, except that the assumed cost of natural gas was changed from being based on the U.S. EIA AEO, which was required by the MIRPP, to being based on Consumers Energy's natural gas price projections. 6 TR 428. The Company developed the additional scenarios based on Consumers Energy's projected natural gas prices because the AEO natural gas prices were substantially different from the Company's gas price outlook. 6 TR 428. The Company identified the three scenarios using EIA's 2017 AEO reference case as BAU AEO, EP AEO, and ET AEO; the Company identified the three scenarios using Consumers Energy's natural gas price projections as BAU Consumers Energy ("CE"), EP CE, and ET CE. 6 TR 428. The Consumers Energy natural gas price scenarios were created primarily to support the Company's Medium 4 retirement analysis. 6 TR 429.

Consumers Energy developed the models used in the IRP process. Consumers Energy's system modeling is based on internal data, and regional market modeling outside of the Company's service area is based on ABB's PowerBase, public sources, and internal planning assumptions. 6 TR 438. The Strategist model simulates the dispatch of all generation resources in the MISO footprint on the basis of a typical week representing each month of the planning period. 6 TR 438. The IRP planning period is January 1, 2018 through December 31, 2040. 6 TR 438. The Strategist software selects incremental capacity additions from various resource options to arrive at a least-cost resource plan that meets capacity Reserve Margin Requirements ("RMR"). 6 TR 438. Strategist optimizes the additional resources based on the portfolios offered, and then ranks the portfolios in economic order. 6 TR 438. Ms. Walz explained that the "result of this overall modeling process is the identification of the most cost-effective resource portfolio for each set of input assumptions for each scenario and sensitivity." 6 TR 439.

The Company constructed and evaluated multiple planning portfolios for each scenario and sensitivity based on criteria such as cost, resource diversity, feasibility, and environmental impact. 6 TR 439. In addition, resource optimizations were performed for each scenario and sensitivity for the entire regional market, which in turn enabled the model to optimize the Consumers Energy system. 6 TR 440. The assumptions involved in the various scenarios and sensitivities are variable and statistical, and were developed by the Company to include the range of reasonably possible values. 6 TR 441.

Due to the volume of calculations made by the Strategist model in performing resource optimizations, the Company did not make available, or “screened out,” certain resource technologies before the scenarios and sensitivities were modeled. 6 TR 443. This screening was based on criteria such as commercial availability, cost, scale, resource type, and technical viability. 6 TR 443-444. Technologies that were screened out include thermal storage, compressed air, flywheel, combined heat and power, fuel cells, geothermal, and distributed generation. 6 TR 444. The Company also performed a preliminary economic analysis based on the LCOE of the remaining technologies, and decided to focus its modeling on the following resources: natural gas-fueled CTs, natural gas-fueled CC units, natural-gas fueled Reciprocating Internal Combustion Engine (“RICE”) units, wind, solar, and battery storage, and the following demand-side resources: incremental additions of energy efficiency and DR, and CVR. 6 TR 445-447.

The Company imposed certain constraints on the Strategist optimization runs in consideration of the feasibility of selected resources, timing of resource availability, amount of excess capacity build permitted, and improving Strategist run time after review of the economic position of one resource over another. 6 TR 448. The primary example of feasibility constraints

is related to wind generation. Since the Company is already planning to add 525 to 550 MW of wind generation by 2021 as part of the Company's RE Plan, incremental additions of wind generation were not permitted to be selected as a potential new build resource prior to 2023. 6 TR 448. The Company also imposed constraints on the amount of wind expansion permitted in the regional market to keep the selection of wind resources close to levels projected by IHS Markit. 6 TR 449. The Company developed constraints related to timing of resource availability to account for significant construction lead time prior to commercial operation date of supply-side resources or significant lead time to ramp up demand-side management programs. 6 TR 449. The Company also limited the amount of excess capacity additions in order to identify which resources are selected first to meet the specified customer demand levels. 6 TR 450.

**b. Results Of Scenario And Sensitivity Modeling**

The Company constructed and considered a range of alternative resource portfolios for each scenario and sensitivity to assess the relative economics and risks of different resource combinations, timing, and amounts. 6 TR 466. The evaluation of the scenarios and sensitivities included a combined total of 225 Strategist optimizations. 6 TR 466. Consumers Energy identified five critical portfolio designs that were evaluated in the IRP. 6 TR 467. Modeling constraints were imposed or loosened in order to evaluate particular portfolio designs, including the types of resources available for selection, maximum RMR, and minimum or maximum allowable number of resources to be built in a given year. 6 TR 467. The five critical portfolio designs are as follows: (i) Portfolio Design A (Reference Portfolio), in which the market purchase of ZRCs is the only resource option for each scenario and sensitivity case; (ii) Portfolio Design B (100% New Build), in which the Company builds supply-side resources to meet all incremental capacity requirements; (iii) Portfolio Design C (Optimal Plan), in which all

supply-side and demand-side resources are offered in the optimization, and thus, represents the Strategist selected portfolio from all available resources; (iv) Portfolio Design D (Preferred Plan, or PCA), which locks into the Strategist optimization the Company's resource determination from the PCA, which was evaluated on all MPSC-required sensitivities and on all base scenarios; and (v) Portfolio Design E ("Alternate Plan"), which represents a feasible capacity replacement option in lieu of the PCA. 6 TR 467-469; Exhibit A-19 (STW-10).

The results of the IRP scenario modeling are reflected in Exhibit A-21 (STW-12), which provides NPV costs for the five critical portfolio options in the six "retirement base case" scenarios, with the "retirement base case" including the retirement of Karn Units 1 and 2 in 2023. 6 TR 471. Exhibit A-21 (STW-12), page 1, lines 1 through 5 summarize the costs associated with each portfolio option evaluated to meet customer demand; lines 6 through 10 compare the economics of each of the portfolio designs to Portfolio Design A (Reference Portfolio). 6 TR 471. For all but a few cases in the BAUCE scenario, meeting capacity requirements with a combination of supply- and demand-side resources is a lower cost option than relying on the market to meet future capacity needs. 6 TR 472. Results of the IRP sensitivity modeling are further provided in Exhibits A-22 (STW-13) through A-28 (STW-19). These exhibits identify, as applicable, assumptions associated with a given sensitivity that increase or reduce customer costs when compared with 100% market purchases, cost savings associated with Portfolio Design C when compared with 100% market purchases, and any cost increase associated with the PCA when compared with Portfolio Design C. 6 TR 479-480. Exhibits A-22 (STW-13) through A-28 (STW-19) also present the corresponding resource plan for the Strategist selection portfolio.

For the Strategist selected resource plans (Portfolio Design C), the selection of resources for the EP CE, ET CE, BAU AEO, EP AEO, and ET AEO scenarios are very similar: (i) they select CVR and EWR in the years 2018 and 2020, respectively; (ii) they select 2,400 MW of wind to replace Karn Units 1 and 2 in 2023 to take advantage of the PTC; and (iii) they select DR and solar in subsequent years. 6 TR 474; Exhibit A-21 (STW-12), page 2. Portfolio Design C provided the building blocks for the PCA by identifying the types of resources that provide the lowest cost to customers and targeting the timing of the resource additions. 6 TR 475. However, the PCA differs from the Strategist selected portfolios in two primary ways: (i) the PCA accounts for realistic timing of development and construction of solar generation build and DR expansion; and (ii) the PCA does not contain large amounts of wind in 2023. 6 TR 475.

Portfolio Design C represents a theoretical selection of resources based on economics, but does not consider other important factors such as construction feasibility, customer rate impact, construction lead time, and land permitting. 6 TR 475. For example, Portfolio Design C in the BAU AEO retirement base case resource optimization for the year 2031 would require implementing 3,200 MW of solar capacity over a one-year period. 6 TR 475. Although this may result in an overall NPV that is a lower cost than the PCA, it also results in several risks, including: (i) the large capital investment required in a single-year; (ii) much less flexible implementation; and (iii) inability to install such a large amount of solar in a single-year. 6 TR 476.

The PCA represents customer savings of between \$485 million NPV and \$2.0 billion NPV compared with 100% market purchases in all scenarios except the BAU CE scenario. 6 TR 472. Under the BAU CE scenario, the PCA would be an increase of \$778 million NPV compared with 100% market purchases. 6 TR 472. While an increased cost to customers is

shown in one of the six potential scenarios, if gas prices increase materially over the Consumers Energy gas outlook or the cost of renewable energy technology decreases by material amounts, the PCA provides the potential for significant savings for customers. 6 TR 472-473. Across the 15 sensitivities presented, the PCA represents a less than 7% increase compared to the Strategist selected portfolio for all sensitivities other than the more extreme 200% gas price sensitivities. 6 TR 483.

**c. Independent Assessment Of Data And Modeling**

Company witness Melissa Haugh, Director at Pace Global, testified as to Pace Global's independent review of the Company's IRP analysis. Pace Global is a leading consultant for integrated resource planning, and has extensive experience in structuring and facilitating IRPs. 8 TR 1450. Pace Global performed an independent review of the Company's analytical approach to the IRP, the key inputs into the IRP analysis, and the alignment of the Company's approach and filing to regulatory requirements. 8 TR 1449.

Ms. Haugh confirmed that Consumers Energy appropriately used the Strategist model in its IRP analysis by running the model for the entire MISO system, offering a wide range of technology options to the portfolio over the forecast period, and performing a step-wise process of several simulations that introduced different subsets of technology options for each scenario and sensitivity. 8 TR 1452. Ms. Haugh also indicated that the Company's key BAU inputs into the model were sound. The inputs included natural gas prices, coal prices, load, cost of new build technologies, capacity prices, emission allowance prices, and key financial inputs. 8 TR 1452. Ms. Haugh testified that: (i) the sources of these inputs are appropriate and commonly used for utility modeling and analysis; (ii) the inputs were sound when compared to Pace Global's own projections over the 20-year planning horizon; and (iii) the scenarios and

sensitivities used in the IRP included an appropriate range of future conditions. 8 TR 1453-1454. Ms. Haugh sponsored Pace Global’s “Independent Review of 2018 Integrated Resource Plan,” which details Pace Global’s review of the Company’s IRP analysis. See Exhibit A-36 (MH-2).

Ms. Haugh testified that: “Consumers Energy’s process and analysis met the characteristics of a prudent Integrated Resource Plan.” 8 TR 1459. The scenarios and sensitivities were consistent with Commission requirements; input sources and guidelines were reflected in the analysis as required; an industry standard resource planning model (Strategist) was appropriately used and relied on; the BAU inputs reasonably reflected consensus or otherwise plausible market projections at the time of the analysis; and key inputs with potential to vary over the forecast period were appropriately varied in the analysis. 8 TR 1459. Pace Global indicated that the Company “performed a robust and structured resource planning analysis that both met the MPSC IRP requirements and focused on Consumers’ primary resource decisions over the study period.” Exhibit A-36 (MH-2), page 6. Ms. Haugh concluded that the PCA “is supported by a sound analysis and consideration of alternate options and uncertainties.” 8 TR 1459.

### **3. Medium Four Retirement Analysis**

In its March 29, 2018 Order in Case No. U-18322, the Commission required that: “the retirement assessment of the Medium 4 units should be submitted as a standalone analysis in the company’s IRP in June 2018.” MPSC Case No. U-18322, March 29, 2018 Order, page 25. Additionally, the Commission’s March 29, 2018 Order stated that the analysis should include an assessment of the following enumerated factors:

“(1) capacity replacement costs; (2) impact of recovery of undepreciated book value; (3) customer rate impact analysis; (4)

non-economic variables such as portfolio balance, employment, and community impact; (5) effect on contractual fuel obligations; (6) near-term revenue requirements; (7) conditions of existing equipment; and (8) execution risk.” MPSC Case No. U-18322, March 29, 2018 Order, page 23.

As directed by the Commission, the Company leveraged the development of this IRP to evaluate the economics of continued operation of the Medium 4 units. The following discusses the modeling of the retirement analysis, the results of the retirement analysis, and the independent Medium 4 retirement assessment.

**a. Modeling Of Retirement Analysis**

One of the primary objectives of the Company’s IRP in this proceeding is to determine the appropriate retirement dates for the Medium 4 generating units. 6 TR 429. The Company determined that it was most prudent to use its natural gas projections in this analysis, and thus created the BAUCE, ET CE, and EP CE scenarios for the purpose of this analysis. 6 TR 429. Exhibit A-29 (STW-20), pages 1 through 3, identify the NPV results for the critical portfolios evaluated on sensitivities associated with the early retirement of the Medium 4 coal units. 6 TR 482-483. The sensitivities included retirement of Karn Units 1 and 2 in 2021 and 2023, retirement of Campbell Unit 1 in 2021 and 2023, retirement of Campbell Unit 2 in 2021 and 2023, and retirement of both Campbell Units 1 and 2 in 2021 and 2023. See Exhibit A-29 (STW-20), pages 1 through 3. The results of the applicable retirement sensitives are modeled in the BAUCE, ET CE, and EP CE scenarios. 6 TR 483; Exhibit A-29 (STW-20), pages 1 through 3. In examining the BAUCE scenario, the modeling results do not significantly favor either continued operation or retirement of the Medium 4 units. 7 TR 887.

The Company also presented the capital and O&M costs associated with various retirement sensitivities for the Strategist selected portfolio (Portfolio C). 6 TR 486. Exhibit A-33 (STW-24) indicates: (i) the mix, amount, and timing of capacity replacement

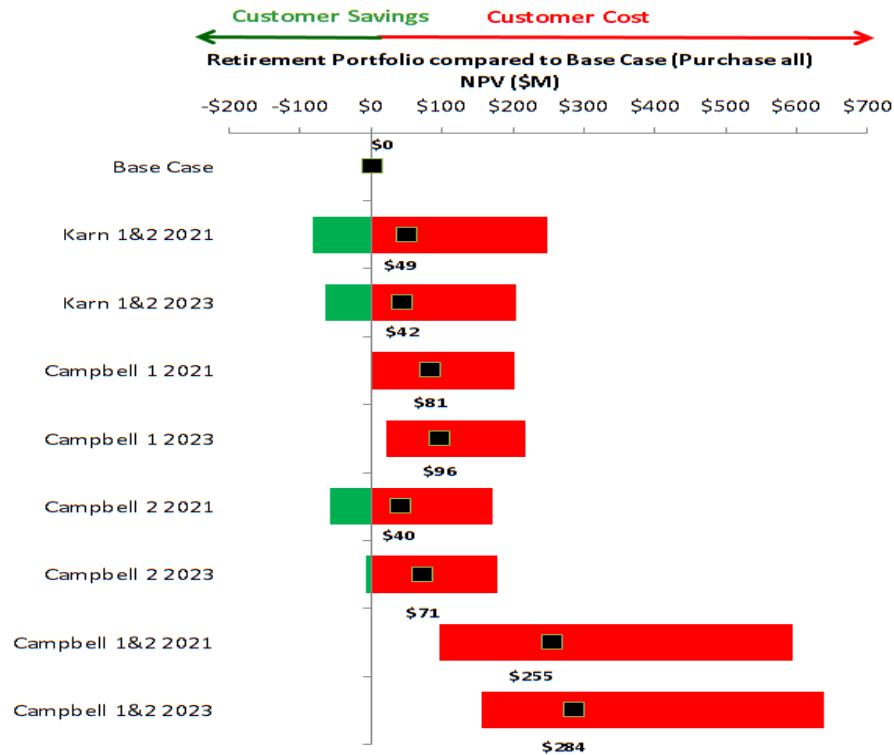
resources from Portfolio C for each retirement sensitivity; (ii) the capital expenditures associated with the resource optimization; (iii) the O&M expenses associated with the resource optimization; and (iv) increases to Power Supply Cost Recovery (“PSCR”) costs resulting from the retirement and capacity replacement plan. 6 TR 486.

**b. Results Of Retirement Analysis**

Mr. Clark described the Medium 4 Retirement Analysis and also provided its results. 7 TR 883-903. Mr. Clark explained that the first step in performing this analysis was to reexamine the ongoing capital expenditures and O&M expenses necessary to continue operation of each of the units between now and the expected end-of-life period, May 31, 2031. 7 TR 883. Additionally, ongoing capital expenditures and O&M expenses for early retirement scenarios of May 31, 2021 and May 31, 2023 were assessed. The Company considered only the joint retirement of Karn Units 1 and 2, because it was determined that it would be impractical to continue operation of just one Karn unit due to site common operations and expenses and fuel delivery efficiencies. However, the Company considered the retirement of Campbell Units 1 and 2 jointly and individually.

Various natural gas prices were considered in developing the range of the NPV of the revenue requirement results. 7 TR 885. The analysis was conducted using natural gas prices ranging from 25% below to 50% above the Company’s BAU natural gas price in increments of 25%. Various capacity prices were also considered and are a function of the MISO Cost of New Entry (“CONE”). 7 TR 885. Capacity prices between 0% and 100% of CONE were considered in this analysis in 25% increments. The Company considers 75% of CONE to be the base case for market capacity prices. The Company’s base capacity price forecast is provided in

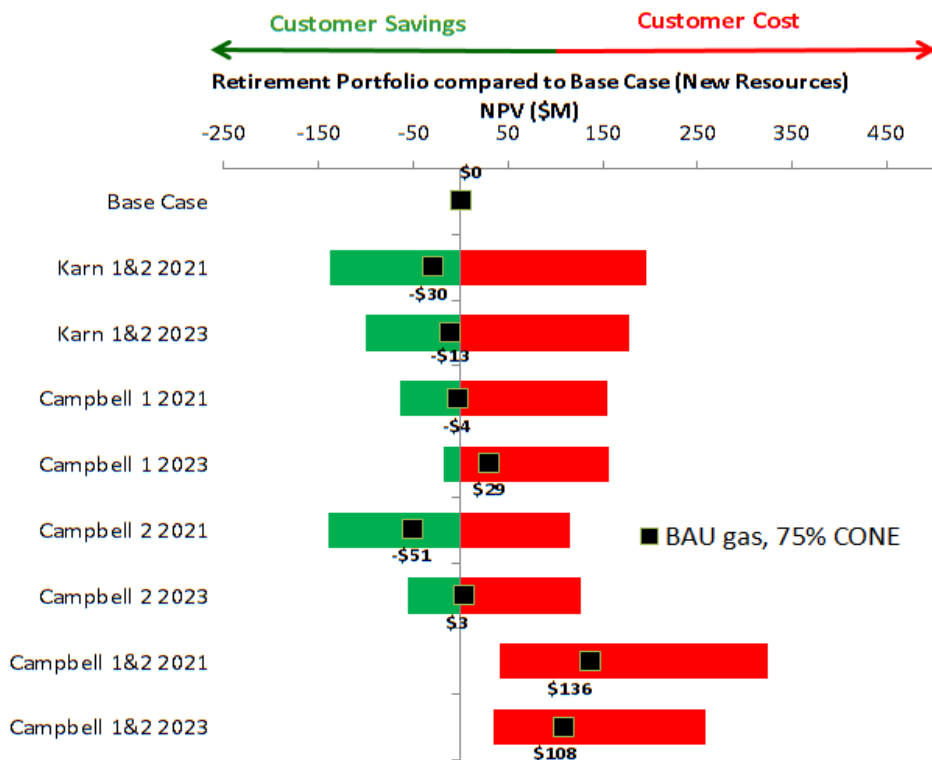
Exhibit A-7 (TPC-5). The results of the above discussed cost/benefit analysis are summarized below:



Mr. Clark explained that the above results are directly comparable to the two previous analyses previously presented by the Company in Case Nos. U-17990 and U-18322. 7 TR 885. However, although the economics of continued operation have improved when compared to the prior analyses, there remains certain capacity and natural gas prices that result in customer benefits if the units are retired early.

Mr. Clark further explained that, to better understand the customer impacts of early retirement and reduce uncertainty, the Company reevaluated the potential retirement of the Medium 4 units using an actual capacity replacement plan. 7 TR 885-886. To accomplish this, the Company leveraged the IRP modeling effort, specifically the BAU CE scenario, and allowed Strategist to identify the optimal replacement capacity for the eight different retirement scenarios considered. The Company then ran the same gas and capacity price sensitivities on each of the

optimal replacement plan results from Strategist. The results of this more comprehensive analysis are summarized in the figure below.



These results above indicate that, when the available replacement resources are considered, there is a small improvement in the economic benefit of retiring the Medium 4 units early. However, the economic justification for early retirement versus continued operation is still not overly compelling, because the results do not significantly favor continued operation or retirement. 7 TR 887. Mr. Clark specifically explained this result as follows:

“The present value of the customer cost impacts that will be realized by avoiding the expected O&M and capital expenditures identified for the Medium 4 is between savings of \$139 million and increased costs of \$284 million. These are deltas in the present value cost of meeting customers’ energy needs over the 20-year planning period. Comparing the possible savings or costs associated with early retirement or continued operation of the Medium 4 to the present value of meeting customer needs over the planning period indicates that the impact of this decision is a shift in costs of less than plus or minus 1.25%. There are many other assumed variables that could easily shift customer costs by this

amount over the same time period. Furthermore, the greatest level of risk for increased costs shown in Figure 4 would require gas prices 50% greater than BAU and capacity prices at 100% of the MISO CONE. Cost impacts corresponding to 75% of CONE and BAU gas price indicates cost impacts at plus or minus 0.2%. This is an insignificant cost variation.” 7 TR 887.

The relative close cost impacts of all of the analysis related to continued operation or early retirement of the Medium 4, establish that these units provide comparable value to customers as other resource options or the market. However, given the environmental investments required to continue operations beyond 2023, Mr. Clark explained that these units should be retired in advance of December 2023 or continue operating through 2031 in order to maximize the environmental investments required to continue operation beyond 2023. 7 TR 889. Therefore, to diversify retirements currently identified for 2031 and to balance execution risk, the Company is proposing to retire Karn Units 1 and 2 based on the favorable economics associated with retirement of these units when compared to Campbell Units 1 and 2. 7 TR 889.

In addition to the above, Mr. Clark provided extensive detail with respect to how the Company complied with each of the eight factors which the Commission required the Company to consider as part of its Medium 4 retirement analysis. 7 TR 890-897; see MPSC Case No. U-18322, March 29, 2018 Order, page 23. This included consideration of: (i) capacity replacement costs; (ii) impact of recovery of undepreciated book value; (iii) customer rate impact analysis; (iv) non-economic variables such as portfolio balance, employment, and community impact; (v) effect on contractual fuel obligations; (vi) Near-term revenue requirements; (vii) conditions of existing equipment; and (viii) execution risk.

The Company also considered the operational complexity of the Company’s coal fleet and capacity investment sensitivities in its retirement analysis. Mr. Clark explained that consideration of operational complexity favors the retirement of Karn Units 1 and 2 over

Campbell Units 1 and 2 because the early retirement of Karn Units 1 and 2 allows for a single coal generation site (i.e., the Campbell Units 1, 2, and 3). 7 TR 898. Mr. Clark further explained that the capacity investment sensitivities considered by the Company indicated that potential changes in required environmental investment are not significant enough to alter the economic-based conclusion that early retirement of any of the Medium 4 units is not compelling, but early retirement of Karn Units 1 and 2 provide slightly better savings for customers. 7 TR 900.

**c. Independent Assessment Of Retirement Analysis**

Company witness Charles F. Adkins, Vice President in the Advisors Consulting Practice of ABB, provided an independent assessment of the potential retirement of the Medium 4 prior to their planned retirement date in May of 2031.<sup>8</sup> 6 TR 315-329. In performing this assessment, Mr. Adkins evaluated the impact of retirement on NUG PPA costs and Fixed Operations and Maintenance (“FOM”) cost streams associated with an earlier retirement of the Medium 4 units.

Mr. Adkins explained that the Company’s NUG PPAs have fixed pricing which is tied to the operation of the Company’s coal-fired generating units (i.e., the Medium 4 units and Campbell Unit 3). 6 TR 318. The base assumption for NUG pricing is based upon the operation of the coal-fired generating units through their planned retirement dates. Therefore, any early retirement of the Medium 4 and Campbell Unit 3 will affect the fixed pricing component in NUG PPAs. 6 TR 318.

To evaluate the impact of retirement on NUG PPA pricing, Mr. Adkins considered different variations of the Medium 4 units retiring in 2021, 2023, and 2031. 6 TR 318-319. Based on this evaluation, Mr. Adkins concluded that, with the exception of when Karn Units 1

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<sup>8</sup> ABB is the owner of the Strategist modeling software program.

and 2 and Campbell Unit 1 all retire in 2031, the Medium 4 retirement combinations with Campbell Unit 1 retiring in 2031 have a reduction in costs to customers. 6 TR 320. These identified that the Campbell Unit 1 2031 retirement scenarios indicate a benefit to customers because they receive cost savings in the form of a reduction in NUG PPA costs. 6 TR 320.

For his Medium 4 FOM analysis, Mr. Adkins used Strategist to model the potential retirement years of 2021, 2023, and 2031. 6 TR 321. In this process, Mr. Adkins used a Generic Natural Gas Combined Cycle (“NGCC”) plant and a Generic Natural Gas Combustion Turbine (“NGCT”) plant to represent the scope of all future build decisions. This is because these resources represent the marginal capacity of the market. 8 TR 322. Mr. Adkins then developed a cost/value related to the various potential early retirement scenarios of the Medium 4 units.

Mr. Adkins explained that the results of the above analysis demonstrate that there is a customer value related to retiring Karn Units 1 and 2 in 2021 and 2023; however, there is a customer cost if Campbell Units 1 and 2 were to retire prior to 2031 as well. Therefore, Mr. Adkins recommended that the Company should consider retiring Karn Units 1 and 2 early, preferably in 2021 or 2023. 6 TR 328. He also recommended that the Company should consider environmental retrofits at Campbell Units 1 and 2 and continue operations until their planned retirement date of May 2031. 6 TR 328. However, following Campbell Units 1 and 2 environmental retrofits, the period from 2023 to 2031, the Company should continue to monitor market developments (i.e., carbon mitigation, low commodity market conditions, and future environmental regulations) to determine if there is any value to retiring Campbell Unit 1 or Campbell Unit 2 early. 6 TR 328-329. Finally, Mr. Adkins explained that the total value of the recommendation to continue operating Campbell Units 1 and 2 and retire Karn Units 1 and 2, generates \$140,791,000 (2017 \$) to Consumers Energy’s customers. 6 TR 329.

#### **4. Risk Assessment**

After completing the extensive modeling process discussed above, the Company selected the PCA as the Company's preferred resource plan.<sup>9</sup> However, prior to finalizing this plan, the Company evaluated the PCA with a complex and robust risk assessment methodology. The Company's risk assessment methodology, which is consistent with the risk assessment methodology mandated by the Commission in Case Nos. U-15896 *et al.*, used a three-step process to assess the levels of risk related to selecting a resource portfolio. In addition, the Company commissioned an independent analysis of the risk assessment methodology used to evaluate the PCA. The Company's risk assessment analysis and the independent analysis are addressed in detail below.

##### **a. Description Of Risk Assessment Methodology And Results**

Company witness Clark explained that the Company used a robust process to assess the level of risk with associated with the PCA. This risk assessment included the following three steps: (i) portfolio optimization reviews; (ii) an NPV review of portfolio optimizations; and (iii) an evaluation of the PCA and expanded sensitivity analysis. Mr. Clark explained each of these steps as follows:

“Portfolio Optimization Reviews – The portfolio optimization reviews are used to identify resource tradeoffs. For example, the model may select a resource plan with a DR resource under a particular scenario or sensitivity. Under another scenario or sensitivity the model may prefer a solar resource. The scenarios developed with different assumptions help to identify the tradeoffs and/or cross-over points, and guide the development of the PCA. Exhibit A-20 (STW-11) provides information about the various resource plans resulting from the modeled scenarios and sensitivities;

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<sup>9</sup> The components of the PCA are discussed in detail in Section III of this Initial Brief.

“NPV Review of Portfolio Optimizations – NPVs help to understand the level of costs customers incur with a particular resource portfolio. By comparing NPVs of portfolio optimizations generated under each scenario and sensitivity, insights into whether customers realize increased costs or savings or remain neutral is determined. These comparisons are made with the portfolio optimizations under each scenario and sensitivity run. This same approach is used when comparing the PCA and alternate plans in each of the developed scenarios. The lowest NPV plan represents the least-cost plan for customers. Exhibit A-29 (STW-20) provides all of the NPVs resulting from the modeled scenarios and sensitivities; and

“Evaluation of the PCA and Expanded Sensitivity Analysis – The above steps are important components of the risk assessment because they are the method by which the final PCA was developed, however, after developing the final PCA, the most important step is to evaluate how it performs in the possible future scenarios. In addition, it is important to understand the impact of certain variables. This allows for the assessment of cost variability impacts and additional understanding of how influential the variable is when small changes up and down occur. The two variables evaluated on the PCA are capacity and natural gas prices. The Company evaluates incremental changes in these prices from the base price forecast used for a particular scenario and sensitivity. Capacity price sensitivities are 0%, 25%, 50%, 75%, and 100% of CONE. The natural gas price sensitivities are -25%, 0%, 25%, and 50% of the base natural gas price forecast.” 7 TR 919-920.

Mr. Clark explained that in the Company’s review of the optimal and sub-optimal resource plans there was preference for renewable and demand-side management resources in the six different scenarios analyzed.<sup>10</sup> 7 TR 921. The lone exception to this result was the BAU CE scenario which preferred a NGCC unit. The Company therefore concluded that the results of step one of the Company’s risk analysis indicated that renewable and demand-side resources were competitive with natural gas units in a future world of higher natural gas prices and/or lower capital costs of renewable resources, demand-side resources, and batteries. 7 TR 921.

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<sup>10</sup> The six scenarios considered by the Company were: (i) BAU CE; (ii) BAU AEO; (iii) ET CE; (iv) ET AEO; (v) EP CE; and (vi) EP AEO.

In the second step of the risk analysis, the Company determined the PCA's NPV under each of the six scenarios to quantify the cost variation associated with the difference in resulting portfolios. 7 TR 927. The NPV review of the build plans for each scenario and sensitivity was assessed at three optimization levels: (i) the reference case, which filled capacity requirements with market purchases; (ii) supply-side resources, which included filled capacity needs with CTs, NGCC, solar resources, wind resources, RICE, and batteries; and (iii) full optimization, which filled capacity needs with the supply-side resources listed above and demand-side resources (i.e., EWR, DR, and CVR). 7 TR 925.

By assessing the changes in NPVs resulting in the scenarios and sensitivities at the above optimization points, the Company was able to reach three conclusions. First, customers incur lower costs in scenarios where renewable resources are selected and capital costs are reduced. 7 TR 927. Second, demand-side resources create customer savings. 7 TR 927. Third, higher natural gas prices cause higher costs to customers, but these higher costs can be offset with the implementation of renewable and demand-side resources. 7 TR 927. The results of the full NPV analysis are provided in Exhibit A-29 (STW-20).

Mr. Clark explained that third step in the Company's risk assessment evaluated the costs of the PCA under each of the six different scenarios. 7 TR 928-931. PCA costs were compared to the full optimization results for each scenario with the expectation that the PCA would be higher cost than the full optimization solution in each scenario, but would have less cost variation across the scenarios. Mr. Clark explained that, after conducting this analysis, the NPV results for the PCA and the full optimization solution confirmed the Company's expectation. 7 TR 928. This is illustrated in the following chart<sup>11</sup>:

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<sup>11</sup> Values represent billions.

	BAU CE	BAU AEO	ET CE	ET AEO	EP CE	EP AEO
PCA	\$21,228	\$23,713	\$19,880	\$22,319	\$20,091	\$22,482
Optimal Plan	\$20,417	\$22,918	\$19,841	\$21,483	\$19,549	\$21,063

In addition to the full optimization plans from each scenario, the Company also developed an Alternate Plan as a reference point. 7 TR 928-929. The Alternate Plan was developed by the Company as a feasible alternative to the PCA, which would still achieve many of the objectives of the IRP; however, it was also believed to be less desirable than the PCA because it relied on an incremental NGCC and a CT plant. 7 TR 928. Mr. Clark explained that the Alternate Plan allowed the Company to assess the level of risk customers incur when natural gas reliance is maximized given the constraints of the Company's Clean Energy Goal. 7 TR 928-929. When comparing the costs of the PCA and Alternate Plan across the six scenarios, Mr. Clark explained that, with the exception of the BAUCE scenario, the PCA performs better across the scenarios by providing lower costs and less variability than the Alternate Plan. 7 TR 929. This is illustrated in the following chart<sup>12</sup>:

	BAU CE	BAU AEO	ET CE	ET AEO	EP CE	EP AEO
PCA	\$21,228	\$23,713	\$19,880	\$22,319	\$20,091	\$22,482
Alternate Plan	\$20,906	\$23,721	\$20,043	\$22,848	\$20,279	\$23,045

After comparing the PCA to the Alternate Plan, the Company also evaluated the influence of natural gas prices on the PCA, Alternate Plan, and various other optimal plans. 7 TR 929. The results of this analysis revealed that the PCA had a lower cost variation than the Alternative Plan and other optimal plans and in all but the BAU CE scenario, the PCA delivered

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<sup>12</sup> Values represent billions.

an equal or lower median cost than the Alternative Plan. 7 TR 931. Mr. Clark explained that this result indicates that the PCA proves the least risk to customer costs. 7 TR 931.

**b. Independent Assessment Of Risk Assessment Methodology**

Pace Global provided an independent assessment of the risk analysis the Company performed to consider the impact of future market conditions on the overall cost and performance of the PCA relative to other portfolio alternatives. 8 TR 1458; Exhibit A-36 (MH-2), page 34. Pace Global noted that Consumers Energy's risk analysis included running both the PCA and the Alternate Plan across the differing scenarios, and comparing the output of the analysis to the cost of the optimal build plans for each scenario. Exhibit A-36 (MH-2), page 34. Pace Global also recognized that Consumers Energy's risk analysis included an expanded sensitivity analysis of the PCA and the Alternate Plan, focusing on the natural gas price and capacity price variables. *Id.* Pace Global found "this approach to risk analysis to be in line with the requirement to perform a risk analysis and the guidelines on approach to performing this risk analysis." *Id.*

Pace Global noted that Consumers Energy's "risk analysis allowed for the comparison of the expected cost and range of costs across alternate market conditions." Exhibit A-36 (MH-2), page 34. When comparing the PCA and the Alternate Plan, the PCA showed a lower cost in all scenarios except the BAU CE scenario, and the Alternate Plan had a higher cost risk based on the standard deviation of portfolio cost across the variation in capacity and natural gas prices. Exhibit A-36 (MH-2), page 34. Pace Global concluded that the Company's risk analysis was "robust and in line with the guidelines for risk analysis offered by the MPSC," and that the "results of this analysis supported the fact that the PCA reduced the cost risk due to commodity price and market changes, to customers." Exhibit A-36 (MH-2), page 35.

### **III. PCA**

#### **A. Resources In PCA**

Based on the extensive development and modeling analysis performed by the Company, as described above, the Company developed a PCA which meets the Company's energy and capacity needs through 2040 and is in the best interests of customers. The resources proposed as part of the Company's PCA, the Company's Clean Energy Goal, and the execution risk of the PCA are addressed in detail below.

##### **1. Description Of Resources**

The Company has presented the PCA in three distinct time periods. 7 TR 903-904. The first time period of the PCA is referred to as the "Near-term" and covers the three years following the Commission's final order in this proceeding (June 2019 through May 2022). The second time period of the PCA is the "Intermediate-term." This period begins at the end of Near-term period and continues through the major capacity replacements in the early 2030's (June 2022 through May 2031). The third time period is "Far-term" and refers to the period that begins at the end of the Intermediate-term and continues through the end of the planning period used in this IRP (June 2031 through 2040).

##### **a. Near-term PCA**

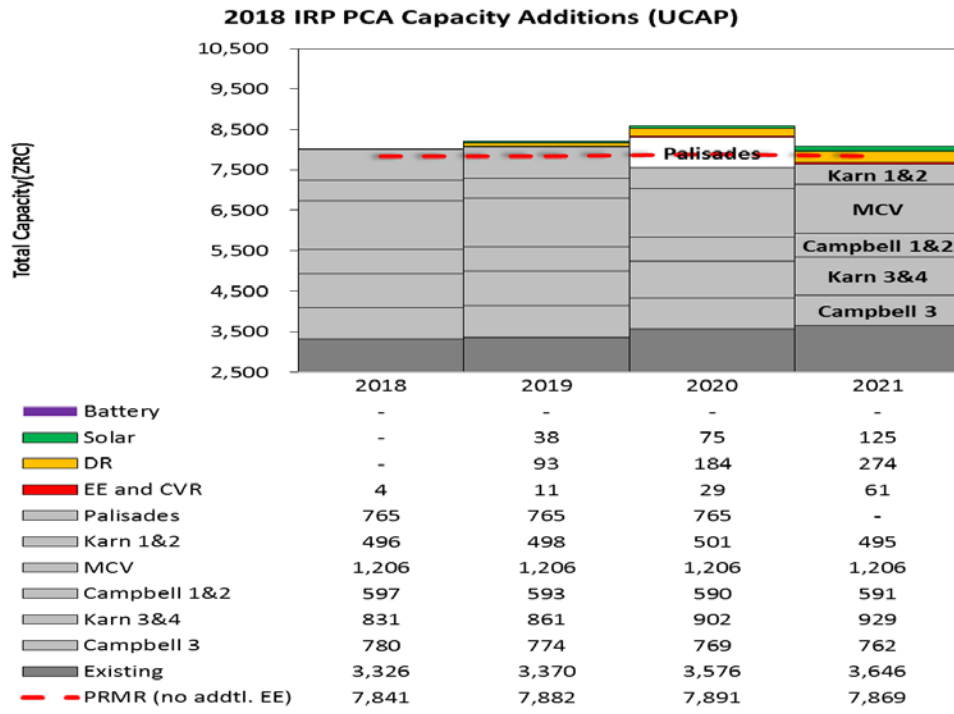
The Near-term of the PCA relies on incremental investment in EWR, CVR, and DR. The Near-term of the PCA also relies on the continued pursuit of demand-side and renewable resources (wind and solar resources) consistent with the Company's Biennial EWR plan Case No. U-18261, the Company's recently filed RE Plan, Case No. U-18231, and the recently filed electric general rate case, Case No. U-20134. 7 TR 904. However, it should be noted that the Company is not seeking Commission approval in this case for the approvals previously granted in Case No. U-18261 or the approvals actively sought in Case Nos. U-18231 and U-20134.

With respect to the EWR resources utilized in the Near-term, Mr. Clark explained that, for 2019, the Company's intends to utilize 1.5% energy efficiency savings consistent with the Company's current EWR Plan and base capacity position and CVR peak reduction capability of 11 ZRCs. 7 TR 905-906. For 2020, the Company proposes to ramp energy efficiency savings from 1.5% to 2% (achieving an average of 1.75% savings) and also ramp CVR to achieve a total of 22 ZRCs. 7 TR 906. For 2021, the Company proposes to maintain 2.0% energy efficiency savings and continue its ramp of CVR to reach a total of 34 ZRCs. 7 TR 906.

For the DR included in the Near-term, the Company intends to add an incremental 93 ZRCs in 2019. 7 TR 906. In 2020 and 2021, the Company plans to continue its ramp of DR by adding 92 ZRCs and 90 ZRCs, respectively. 7 TR 906. In total, this ramp of DR will provide an incremental 274 ZRC by 2021 compared with projected 2018 levels. 7 TR 906.

The Company intends to utilize wind and solar resources in the Near-term PCA in a manner consistent with the Company's RE Plan in Case No. U-18231 and the Commission's orders in Case No. U-18090. 7 TR 906. Specifically, the Company is proposing to add 525 MW of new in-state wind resources by December 2020, as included in the base capacity position, and an incremental 25 MW of new in-state wind resources by December 2020. 7 TR 906. The Company is also planning to add 150 MW of incremental PURPA QF solar (75 MW in 2019 and 75 MW in 2020), as mandated by the Commission in Case No. U-18090, and accelerate the 100 MW of solar proposed in the Company's RE Plan to achieve commercial operation in 2021. 7 TR 906.

The following chart illustrates the resources included in the Near-term PCA and the timing of those resources:



**b. Intermediate-term PCA**

Mr. Clark explained that the Intermediate-term PCA includes two primary considerations: (i) the need to replace the capacity lost by the proposed retirement of Karn Units 1 and 2 in 2023; and (ii) the need to begin ramping up new generating resources to replace the MCV PPA after it terminates in 2030<sup>13</sup> and the retirement of Campbell Units 1 and 2 and Karn Units 3 and 4 in 2031, which provide a collective 3,100 MW of capacity.

The Company is proposing to replace the capacity lost by Karn Units 1 and 2 in 2023 with demand-side resources. Specifically, the Company proposes the continuation of 2.0% EWR savings through 2023, the continued expansion of CVR through 2023 and the expansion of DR

<sup>13</sup> As explained above, the Company’s Baseline Capacity Position assumes that the Company will execute its unilateral right to extend the MCV PPA at a reduced capacity rate from 2025 to 2030. As the termination of the MCV PPA in 2025 draws closer, the Company intends to continue to evaluate the economics of a PPA extension with MCV. 7 TR 909.

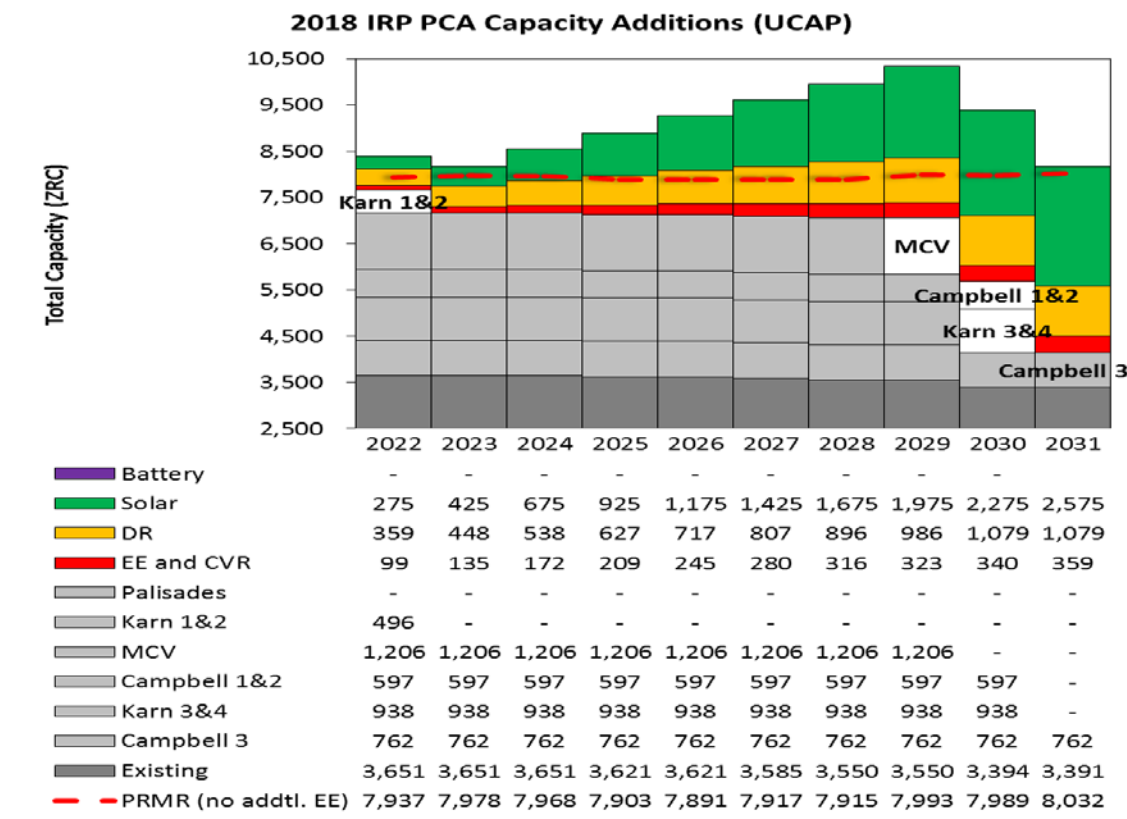
by 400 MW by 2023. 7 TR 907. In addition, the Company plans to leverage the proposed ramp of solar resources, which, as discussed below, will be utilized to replace a large amount of capacity lost in the early 2030s, and to allow for a more consistent year-over-year build of DR between now and 2030. 7 TR 907. Mr. Clark explained that this approach resulted in a reduction of DR as a backfill resource for Karn Units 1 and 2 in 2023 to allow for increases in DR later in the decade. 7 TR 907.

The Company is proposing to replace the capacity lost by the termination of the MCV PPA and the retirements of Campbell Units 1 and 2 and Karn Units 3 and 4 with demand-side and solar resources. The Company is proposing to continue the 2% energy efficiency savings, as projected to be reached prior to the retirement of Karn Units 1 and 2, which will reduce the Company capacity need in 2031 by 245 ZRCs. 7 TR 909. The Company is also proposing the incremental addition of approximately 90 ZRCs of DR annually through 2030 (increasing DR to a total of 1,079 ZRCs over 2018 levels). 7 TR 909. Furthermore, the Company plans to leverage the grid infrastructure investments to enable CVR to continue deployment of this resource and achieve a total of 115 ZRCs by 2031.

Solar generation will be the predominant resource which replaces MCV, Campbell Units 1 and 2, and Karn Units 3 and 4. The Company's PCA proposes to fill the 2030 and 2031 capacity need with up to 5,150 MW (2,575 ZRCs) of constructed and contracted solar generation resources. 7 TR 909. The PCA includes a "glide path" of solar generation which will begin additions of this resource to fill the need in 2030 and 2031 as early as 2022. 7 TR 910. Mr. Clark explained that this glide path will allow time for operating and assessing a system with significant solar generation, allow for a more gradual impact on customer rates, and minimize

execution risk associated with the construction of significant amounts of solar generation. 7 TR

910. The Company’s Intermediate-term PCA is illustrated below:

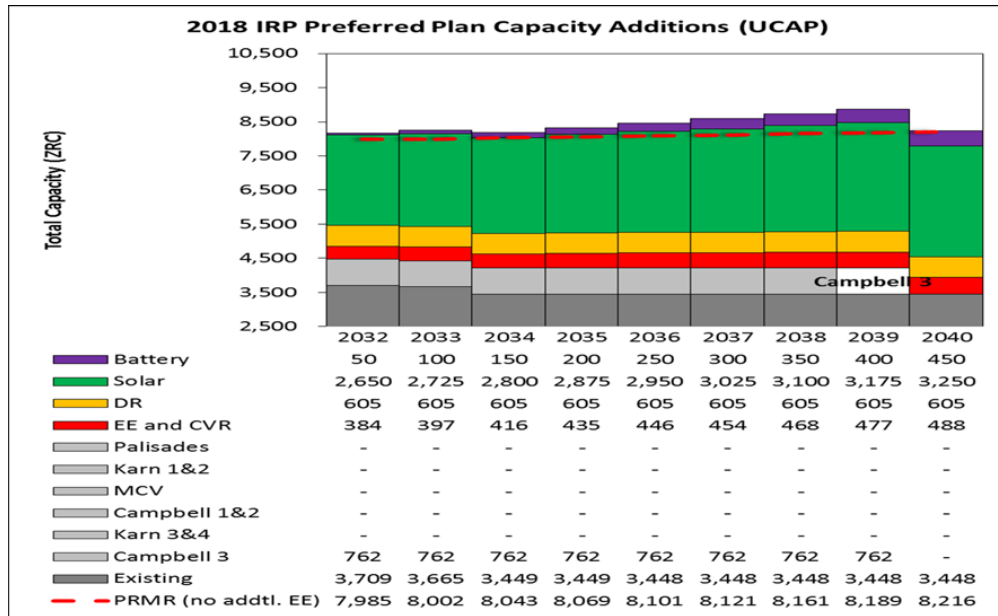


**c. Far-term PCA**

The Company’s Far-term PCA addresses projected load growth and the replacement of Campbell Unit 3 in 2039. 7 TR 910. The Company expects to continue operating the Zeeland Plant and Jackson Plant through the end of the planning period. 7 TR 910. As was the case with the Near and Intermediate-term periods of the PCA, the Company intends to maintain its strategy of meeting capacity and energy needs with a combination of demand-side and renewable resources.

Specifically, the Company is proposing to increase energy efficiency savings to 2.25% annually beginning in 2030 and to continue at that level through 2040. 7 TR 911. The Company does not propose any additional DR beyond 2030, but will maintain the high level of penetration

achieved in the Intermediate-term. 7 TR 911-912. In addition to the resources above, the Company proposes to add battery storage to fill load growth needs, resulting in 450 MW of storage by 2040. 7 TR 912. Finally, the Company is proposing 1,350 MW of additional constructed and contracted solar generation (675 ZRCs) between 2031 and 2040 to fill the need created by the retirement of Campbell Unit 3 at the end of 2039. 7 TR 912. The Company’s Far-term PCA is illustrated below.



**2. Description Of Clean Energy Goal**

Company witness Breining discussed the Company’s corporate clean energy goals in her direct testimony. Articulating the Company’s commitment to “leave Michigan better than we found it,” Ms. Breining explained the Company’s environmental goals as follows:

“In the past five years, Consumers Energy has created a cleaner, more sustainable energy future for the state by taking a leadership position in reducing air emissions, reducing water usage, saving landfill space, and boosting the amount of renewable energy supplied to customers. Consumers Energy plans to meet Michigan’s energy needs by reducing carbon emissions by 80% and no longer using coal to generate electricity by 2040. To meet this goal, we believe that more than 40% of the energy produced could come from renewable sources and energy storage by 2040.

This continued transformation to cleaner fuel sources is part of a long-term strategic commitment to protect the planet.

“Through 2017, our actions have reduced our carbon emissions by 38%, reduced our water usage by 35%, and avoided over one million cubic yards of landfill disposal. These accomplishments have encouraged us to do more. Recently, the Company also announced new five-year environmental goals for Michigan water, waste, and land, including:

- “i. Water: save 1 billion gallons of water;
- “ii. Waste: reduce waste to landfills by 35%; and
- “iii. Land: enhance, restore, or protect 5,000 acres of land in Michigan.” 8 TR 1764.

As Ms. Breining further explained, the Company is committed to maintaining “a robust environmental compliance program and creating a cleaner, more sustainable energy future for the State of Michigan.” 8 TR 1764. To that end, Exhibit A-92 (HAB-3) demonstrates that the Company’s BAU outlook leaves the Company 15% short of meeting the 80% reduction in carbon emissions goal, while the PCA helps the Company to exceed the 80% target and is actually projected to achieve a 92% reduction in CO<sub>2</sub> emissions by year-end 2040. 8 TR 1765.

### **3. Execution Of PCA**

#### **a. Solar Development**

The Company’s PCA proposes to execute up to 5,150 MW (2,575 ZRCs) of constructed and contracted solar generation resources – some of which will be brought online as early as 2022. While the Company is able to completely replace the capacity lost by the proposed retirement of Karn Units 1 and 2 with demand-side resources, the Company is leveraging the ramp up of solar to replace capacity lost in 2030 and 2031 to diversify the Karn Units 1 and 2 backfill plan. This allows time for operating and assessing a system with significant solar generation, to allow for a more gradual impact on customer rates, and to minimize any execution

risk associated with the development of 5,000 MW of solar generation through 2030. 8 TR 1379.

The incremental approach to developing solar is reasonable and in the best interest of customers. Company witness Thomas testified that the incremental approach to developing the amount of solar under the PCA is reasonable because:

“The approach anticipates technological advances in the early years of the plan that reduce costs;

“The Company will gain important development, construction, and operating experience during the early years of the plan;

“The Company will apply experience and cost improvements to larger build totals later in the plan to improve overall performance and costs; and

“The Company anticipates third party development opportunities improving locational diversity, project development timeframes as compared to the Company, and / or lower costs for customers.”  
8 TR 1382.

For purposes of modeling in this case, the Company assumed installation of solar photovoltaic utility scale, ground-mounted fixed tilt panels for the IRP PCA. However, the Company’s PCA should be viewed as having no preference as to solar technology. 8 TR 1392. The Company expects that advances in manufacturing and continued technology improvements including, such as advanced tracking systems will drive the cost reductions built into the plan. Over the years, the Company anticipates that the best available technology will change. 8 TR 1379.

The development of a typical solar facility takes approximately two to three years. The development process involves site selection, land acquisition, building community relationships, community education, environmental impact studies, permitting, arranging for the electrical interconnection, engineering, proper regulatory reviews and approvals, and contracting for the

equipment and construction services prior to commencement of construction. 8 TR 1382. The timing for bringing a new solar facility online is accounted for in the IRP.

An essential component of solar development is real estate. A typical solar facility requires four to six acres per megawatt of capacity. For the PCA, the total real estate needed, for 5,000 MW of solar through 2030, is approximately 25,000 to 35,000 acres over the term of the plan. 8 TR 1383. Using U.S. Geological Survey, 20141010, NLCD 2011 Land Cover (2011 Edition, amended 2014) and a Michigan parcel dataset purchased from CoreLogic - Version: 2018 Quarter 1, these databases show that the Lower Peninsula has more than sufficient land to implement the PCA. 8 TR 1383-1384. Such real estate will need to be geographically diverse to reduce significant electric system disruptions due to cloud cover, meet electric system standards, and be safely integrated into existing electrical infrastructure. This also has the potential to mitigate community concerns over “too much” solar installed in one area and provide additional optionality to ensure the lowest cost locations can be utilized. 8 TR 1383.

Under the PCA, the Company proposes to construct solar generation or procure solar capacity through competitively bid build transfer agreements, development asset acquisitions, or PPAs. The Company’s plan contemplates adding solar capacity in smaller increments than traditional fossil, base-load generating plants. 8 TR 1380. The smaller increments of solar enable a more gradual impact to customer costs, compared to installation of large centralized generating stations, and allows for more planning flexibility. 8 TR 1380. The Company’s PCA does not assume that Consumers Energy would be constructing the solar unilaterally. In fact, the PCA recognizes that third party development would be an integral component to the plan, with developers and independent power producers creating more flexibility, diversity of locations, competitive pricing, and capability to develop the amount of solar in the plan. 8 TR 1381-1382.

Under the PCA, solar capacity - whether owned by the Company, projects purchased from developers, or purchased through PPAs - would be awarded based upon competitive bids. Through this process, the Company anticipates selecting projects that deploy the best available technology as reflected in key parameters such as on-peak capacity and overall cost of energy. 8 TR 1392.

Through the competitive bidding process, as discussed in greater detail below, the Company will solicit bids for a specific amount and type(s) of new generation capacity needed. Under this framework, independent power producers may submit bids in response to the Request for Proposal (“RFP”) for the specific types of new generation identified. Additionally, the Company would also submit bids in response to the RFP for the specified project. 8 TR 1381. In order to develop and submits bids in for the RFP, the Company would perform early stage development. This would include acquiring real estate and local permits, applying for GIAs, performing preliminary engineering, obtaining firm prices for the acquisition of equipment and construction services, and establishing plant performance expectations such that firm construction costs and levelized costs of delivered energy. 8 TR 1381. As surety of the solar supply chain, which consists primarily of solar panels and construction labor, will be critical, the Company will work on forming strategic alliances that could enhance the supply chain for both construction labor and materials for participants in this solar build to assure adequate quality materials, equipment, and labor are available to complete the construction of the large amounts of solar anticipated in the PCA. 8 TR 1385.

After the competitive bidding is finalized, the Company anticipates construction process to be undertaken for the new solar facilities. As many of the solar facilities are likely to be built by third parties, the Company will exercise appropriate diligence in its limited oversight of the

construction program of others to assure completion. 8 TR 1385. To the extent the Company builds solar, the Company will manage such a construction program in regions, forming multiple teams during the ramp up years such that lessons learned in development and construction will be applied locally to improve future year's construction performance. 8 TR 1385. This process will allow for the development of solar under the Company's PCA.

**b. DR Program Growth**

The Company plans to grow its DR Program beyond present levels, with much of the growth occurring as a result of changes proposed in the Company's pending electric rate case, Case No. U-20134. Mr. Ennis explained the Company's proposal in Case No. U-20134 to change its Dynamic Peak Pricing programs, namely to replace its Critical Peak Pricing ("CPP") and peak rewards options with a Universal Peak Rewards ("UPR") provision across all residential customers. Under UPR, residential customers would receive \$0.95 per kWh as a bill credit for every kWh reduced during a peak event, but would not incur a penalty if they did not reduce their use. 8 TR 1519. As the UPR would require the Company to reconfigure its communication and billing systems and performance testing, the Company would begin transitioning customers into the UPR provision over 2020, with full enrollment by the summer of 2021. 8 TR 1521. Customers could opt out of receiving DR event communications, but would still be eligible for credits if they reduced their usage. 8 TR 1521. Mr. Ennis explained that the cost to implement UPR was primarily related to system upgrades, and projected to require approximately \$10 million of capital expense in 2019. 8 TR 1522; Exhibit A-61 (PCE-2). The DR base case in the IRP is based on the costs provided in Case No. U-20134.

Mr. Ennis also testified regarding the Company's request in Case No. U-20134 to augment its AC Peak Cycling Program by developing and testing the use of smart thermostats in

a Bring Your Own Thermostat (“BYOT”) pilot. 8 TR 1525. The program would use cloud-based software deployed through the customer’s Wi-Fi thermostat to perform a day-ahead energy optimization of the home to achieve greater demand savings. The pilot would run during the summer of 2019 and initially target 2,500 customers. The projected cost of developing and implementing this pilot is \$2.2 million. Neither the cost of the pilot nor the projected MW reductions have been incorporated into this IRP. 8 TR 1525.

**c. EWR Program Growth**

As part of the PCA, the Company is proposing to increase its current 1.5% EWR energy savings per year to 2.0% energy savings per year in 2021 through 2029, and 2.25% per year beginning in 2030. 8 TR 1581; Exhibit A-63 (TAY-1). Company witness Theodore A. Ykimoff, Director of EWR Programs, explained that these projected amounts of energy savings are reasonable for the following reasons: (i) the Company has consistently delivered the energy savings approved in its EWR Plans since 2009; (ii) the Company has a trade ally network of over 2,000 business partners that are instrumental in the successful reduction of customer energy waste; (iii) the Company relies on the expertise of nationally recognized implementation contractors to assist in designing, planning, and implementing EWR programs in Michigan; and (iv) the Staff-led EWR workgroup identified energy potential savings in Michigan of approximately 2.0% per year between 2018 and 2029. 8 TR 1581. Mr. Ykimoff also identified six other states<sup>14</sup> that have energy efficiency targets between 2.0% and 2.9% per year between 2016 and 2020. 8 TR 1582. In addition, based on the Statewide Study, GDS confirmed that 2.0% of annual savings is a reasonable estimate for cost effective electric EWR measures over the next 20 years in the Consumers Energy service area. 8 TR 1614-1615.

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<sup>14</sup> The six states are Massachusetts, Rhode Island, Arizona, Maine, Vermont, and Maryland. 8 TR 1582.

Consumers Energy recognizes that uncertainties exist in potential EWR energy savings. A Department of Energy study highlighted a number of assumptions that can impact the level of savings potential, such as the treatment of future ET and the level of avoided costs. 8 TR 1582. Consumers Energy will continue to evaluate potential energy savings as part of future IRP and EWR proceedings, and may propose adjustments to energy savings levels as necessary. 8 TR 1582, 1586.

**d. CVR**

To implement CVR, the Company would begin operational testing and validation in mid-2018 with a target of 20 circuits. 8 TR 1622. The goal of the test would be to verify software and device functionality, and to develop standard CVR operational procedures. The Company would verify and improve its practices for circuit selection and planning methods, data gathering and analysis, as well as validate its benefit analysis. 8 TR 1622-1623.

In order to grow advanced grid capabilities, the Company would deploy technologies across three categories: Telecommunications, Grid Devices, and Advanced Applications. 8 TR 1623. There are many factors at play to determine the best sequencing of grid modernization investments for customer benefit. First, the Company would need to make simultaneous, coordinated investments across all three categories to achieve the greatest benefits for customers, as the full potential benefits from these technologies are only realized when all three are in place. For this reason, the rollout strategy would involve scaling groups of grid modernization technologies on the highest benefit areas of the grid over time (as opposed to, for example, deploying all Automatic Transfer Reclosers (“ATRs”) before moving on to the next grid device). Second, the Company would consider the maturity of technologies in the rollout plan, with a focus on scaling deployment of technologies with known and proven benefits first, while having

smaller-scale deployment of technologies that the Company is still testing. Third, the deployments would be limited by the available funding for these programs, which is balanced across a variety of needs on the distribution system. 8 TR 1623-1624.

The deployment plan for the dependent automation programs, as presented in the Company’s five-year Electric Distribution Infrastructure Investment Plan (“EDIIP”) in Case No. U-20147, details the five-year capital investment plan and unit forecast for key program dependencies including Distribution Supervisory Control and Data Acquisition (“DSCADA”) and Regulator Controller. These automation projects, summarized below, must receive continued funding for the CVR Program to achieve full benefit.

**- CAPITAL: ADVANCED CAPABILITIES INFRASTRUCTURE: AUTOMATION**

<b>5-Year Capital Plan</b> <i>(all values in \$ millions)</i>								
Investment Categories	2015	2016	2017 prelim	2018	2019	2020	2021	2022
DSCADA	6	4	8	10	8	10	12	13
SCADA	-	-	1	2	2	2	2	2
ATR	0	1	3	9	16	19	22	22
Line Sensors (early deployment)	0	1	1	1	1	1	1	1
Regulator Controllers (early deployment)	-	1	0	3	4	6	6	6
<b>Total</b>	<b>6</b>	<b>7</b>	<b>13</b>	<b>24</b>	<b>31</b>	<b>39</b>	<b>43</b>	<b>44</b>
<b>Unit Forecast</b>								
Investment Categories	2015	2016	2017	2018	2019	2020	2021	2022
DSCADA	31	21	64	60	50	65	70	80
SCADA	-	-	42	50	50	50	50	50
ATR (loops)	5	5	11	60 (14)	50 (17)	65 (20)	70 (22)	80 (22)
Line Sensor Sets (individual units)	6 (18)	39 (117)	15 (47)	90 (300)	150 (50)	150 (50)	150 (50)	150 (50)
Regulator Controllers	-	-	8	50	75	100	100	100

Non-infrastructure based projects would also affect the CVR deployment plan. 8 TR 1629. Mr. Ortiz testified regarding the Company’s strategy and planning that informed low voltage distribution capital investment and O&M spending decisions for the 2019 test year, as provided in Case No. U-20134. The Company’s plan includes investing \$27.5 million for Grid

Capabilities: Advanced Technologies in 2019. These advanced technologies, specifically Advanced Distribution Management System (“ADMS”) and Electric System Model Enhancement (“ESME”), will enable additional efficiency improvements through the use of model-based optimization and enhanced software capabilities; \$16.1 million for ADMS and \$11 million for ESME are direct dependencies of the CVR Program. These projects must be approved in order to realize full CVR benefits. To the extent that any capital costs are not approved in Case No. U-20134, the Company requests that they be approved in this case. 8 TR 1629-1630.

Additionally, in order for the CVR Program to be successful, necessary funding must be allocated towards the conditioning of circuits and devices that are within CVR project scope. 8 TR 1630. As presented in the EDIIP, the plan to enhance grid capabilities is linked to the Company’s ongoing maintenance programs and traditional infrastructure upgrades. CVR will be utilized as a tool to prioritize circuit conditioning where spending is aligned with benefits. Mr. Ortiz explained that distribution device maintenance is a critical requirement to achieve full CVR benefits, and it includes capacitor and regulator maintenance such as blown fuse repair, regulator tank replacement, and oil switch repair.

Consumers Energy would need additional personnel to support this project. 8 TR 1632. As shown in Exhibits A-67 (MAO-1) and A-68 (MAO-2), the labor associated with these new positions is built into the CVR Program plan. Additionally, the Company intends to ramp up the number of resources as the number of deployed circuits increases. For example, once 100 circuits are deployed, the company will increase Engineering, Controller, and Supervisory Control and Data Acquisition Support staffing to ensure that program resources do not surpass their bandwidth for monitoring, operating, or maintaining CVR Program objectives.

#### **4. Commission Planning Objectives**

Mr. Clark summarized how the Company's PCA satisfies the Commission's planning objectives as provided in MCL 460.6t(8)(a). The detail supporting each of the planning objectives is provided by numerous Company witnesses and addressed throughout this Initial Brief.

Resource Adequacy and Capacity Requirements: Mr. Clark explained that the PCA provides incremental capacity where appropriate for the Company to meet customers' needs. 7 TR 914. The resources selected in the PCA can be counted on to meet PRMR. All incremental resources are planned to be located within MISO LRZ7 ensuring they will contribute sufficiently to local reliability.

Compliance with Environmental Regulations: Mr. Clark explained that the PCA phases out fossil fuel emissions while maintaining affordable rates and bills by relying on clean, non-carbon emitting resources throughout the planning period. 7 TR 914.

Competitive Pricing: Mr. Clark explained that the overall price impacts of the PCA are reasonable. 7 TR 914. The customer rate impacts associated with the PCA are limited to 0.68% compound annual growth over the planning period. Additionally, the Company's strategy of modular deployment of new generation resources allow for a phasing in of costs, which limit the rate impact year over year. Finally, the Company's plan to competitively bid all new supply-side generation needs provides further opportunity to realize lower customer cost impacts.

Reliability: As explained above, the Company's PCA provides sufficient capacity to meet the Company's expected PRMR. Furthermore, the Company's plan to keep all new demand and supply-side resources located within MISO LRZ7 ensures that the Company will be able to meet its share of the LRZ7 LCR. 7 TR 914. Finally, the PCA incorporates incremental

levels of renewable and demand-side resources to ensure adequate time to understand the effects on reliability of the bulk electric system, and to modify the development or implementation as necessary to maintain that reliability.

Commodity Price Risk: The Company's PCA minimizes commodity price risk with proposed renewable and demand-side resources. 7 TR 915. This minimization of risk was confirmed by the selection of solar and demand-side resources in certain scenarios using both the Consumers Energy natural gas price forecast and the AEO natural gas price forecast. Additionally, Mr. Clark explained that, in the Company PCA risk analysis, the variance in costs of the PCA under differing natural gas prices is notably less than the variance in costs of the Alternate Plan under the same differing gas prices. 7 TR 915. This is caused by less exposure to the natural gas commodity costs through the selection of more renewable resources and less natural gas fired generation in the PCA, as compared to the Alternate plan. Mr. Clark further explained that natural gas price variations drive changes in energy market purchase costs within the Strategist production cost model. 7 TR 915. This implies that the resources in the PCA provide energy with limited incremental commodity cost and reasonable energy market exposure.

Diversity of Generation Portfolio: Mr. Clark explained that the generation portfolio produced by the PCA is diverse. 7 TR 915. While the incremental additions of new capacity are dominated by solar resources, the plan still incorporates a blend of demand-side resources, contractual agreements, wind resources, natural gas fired generation, coal-fired generation, and battery storage. Therefore, no resource is overly relied upon in the PCA.

Reasonable and Cost-effective Demand Side and Renewable Resources: The PCA relies on clean energy resources such as DR, wind resources, and solar resources. 7 TR 916.

Mr. Clark explained that the steady ramp of demand-side resources ensures that consistent and effective marketing can be developed and deployed. Additionally, the selection of solar resources as a primary resource in the PCA allows for modular deployment that can be adjusted, altered, delayed, or accelerated to capitalize on cost advantages and technology development. 7 TR 916-917. These features of the PCA ensure cost effectiveness for our customers and Michigan.

## **5. IRP Report**

The Commission's IRP filing requirements, as approved in Case Nos. U-15896 *et al.*, require "[a] schedule to report the status of an approved IRP plan in accordance with MCL 460.6t(14)." Consistent with this requirement and MCL 460.6t(14), the Company proposes to file annual reports with the Commission by May 31 of each year regarding the projects approved as part of the Company's Near-term portion of the PCA. 7 TR 918. These reports would be filed subsequent to the completion of the years within the Near-term PCA and the first of such reports would be filed in 2020. 7 TR 918. Mr. Clark explained that these reports will update the Commission on the status of all projects and investments which will be commenced by the Company subsequent to the Commission's approval of the PCA. 7 TR 918-919.

### **B. Cost Approvals**

MCL 460.6t(11) provides that, in approving an IRP, the Commission shall specify the approved costs for future recovery as follows:

"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."

Consistent with MCL 460.6t(11), the Company is proposing the recovery of costs related to the EWR, DR, and CVR resources which will be commenced within three years of the Commission's expected approval of the Company's IRP and PCA. Since a final order is required to be issued no later than 360 days after an electric utility files an IRP, the Company has used June 1, 2019 through May 31, 2022 as the three-year cost recovery approval period in this case. See MCL 460.6t(7).

#### **1. DR**

Pursuant to MCL 460.6t(11), the Company requests approval of capital costs in the amount of \$21,028,357, and a total O&M cost of \$36,272,652, to implement its planned DR expansion to achieve a total peak load reduction of 607 MW (an incremental 238 MW from 2019 levels proposed in the Company's pending electric rate case) by June 1, 2022. Mr. Ennis fully supported the Company's levels of capital and O&M costs for the period 2019 through 2022 in his Exhibit A-61 (PCE-2), which is summarized in the table below:

Michigan Public Service Commission						
Consumers Energy Company						
Projected DR Capital & O&M Cost By Year						
2019-2040						
Line No		2019	2020	2021	Jan-May 2022	Total Incremental
	<b>Capital</b>					
	Hardware					
1	Hardware Cost (Labor)	\$ 2,571,567	\$ 2,475,298	\$ 2,365,157	\$ 933,718	\$ 5,774,173
2	Hardware Cost (Equipment)	\$ 6,302,083	\$ 6,700,052	\$ 5,988,120	\$ 2,324,344	\$ 15,012,517
3	Hardware Cost (Equip Replace +20)	\$ -	\$ -	\$ -	\$ -	\$ -
4	Technology Development	\$ 10,568,350	\$ 100,000	\$ 100,000	\$ 41,667	\$ 241,667
5	Facility Audit/Set-up	\$ -	\$ -	\$ -	\$ -	\$ -
6	Capital Total	\$ 19,442,000	\$ 9,275,350	\$ 8,453,278	\$ 3,299,729	\$ 21,028,357
	<b>O&amp;M</b>					
7	Marketing	\$ 2,493,737	\$ 2,425,974	\$ 2,366,259	\$ 952,967	\$ 5,745,200
8	Annual Software Licenses	\$ 1,281,012	\$ 2,787,120	\$ 4,002,930	\$ 1,964,138	\$ 8,754,188
9	Operations	\$ 1,687,594	\$ 1,672,525	\$ 1,754,281	\$ 749,068	\$ 4,175,874
10	Participant Acquisition Fee	\$ -	\$ -	\$ -	\$ -	\$ -
11	Portfolio Management Fee	\$ -	\$ -	\$ -	\$ -	\$ -
12	Incentives	\$ 4,313,682	\$ 5,856,883	\$ 7,637,240	\$ 3,509,934	\$ 17,004,057
13	O&M Total	\$ 9,776,025	\$ 12,742,502	\$ 15,760,710	\$ 7,176,107	\$ 35,679,319
14	Incremental Based on AEG Study	\$ -	\$ -	\$ -	\$ 593,333	\$ 593,333
15	Total with Incremental Costs	\$ 9,776,025	\$ 12,742,502	\$ 15,760,710	\$ 7,769,440	\$ 36,272,652

8 TR 1523.

Mr. Ennis testified that the Company agreed with Staff witness Katie J. Smith's recommendation that O&M expenses associated with DR should be approved in the Company's general rate case. 8 TR 1542. Thus, the Company agrees that O&M costs related to DR will undergo review and approval in a general rate case in accordance with the three-phase DR framework ordered by the Commission in Case No. U-18369. Mr. Ortiz went on to note that the Company's DR O&M expenses and capital investment are linked together such that the Company's implementation of DR programs approved in this case are dependent upon approval of associated DR O&M expenses.

## 2. CVR

The Company requests approval of the costs of its CVR deployment, to achieve a total peak load reduction of 44 MW (incremental 40 MW) by June 1, 2022, as follows: capital costs of \$8,924,600 and O&M costs of \$666,600. As discussed below, Mr. Ortiz fully supported these

costs in his Exhibit A-69 (MAO-3), which provided the cost detail for the CVR Program beginning in mid-2019 through mid-year 2022.

Mr. Ortiz presented the Company's annual projected capital expenditures for the CVR Program through the year 2028 in Exhibit A-67 (MAO-1). Exhibit A-67 (MAO-1) provided the number of circuits scheduled for deployment, both per year and cumulatively, the anticipated expenditures for labor, and the capital investment for circuit upgrades and conditioning. The primary component of this investment is for Grid Modernization circuit upgrades, specifically the deployment of DSCADA and Regulator Controllers. 8 TR 1626. While other Grid Modernization initiatives, which are addressed in Case No. U-20134, support CVR deployment, they do not fully cover all CVR requirements. The capital expenditures in Exhibit A-67 (MAO-1) cover additional CVR requirements above and beyond Grid Modernization investments. Both Grid Modernization and CVR Program capital investments are required in order to realize the expected benefits from CVR. 8 TR 1626-1627. While the majority of the expenditures are planned to support DSCADA and Regulator Controller deployments, other potential capital investments which may be required to make a circuit viable for CVR include transformer upgrades and line re-conductoring. These capital expenditures are prerequisites to enabling the CVR technology on additional circuits. 8 TR 1627.

Mr. Ortiz sponsored the Company's annual forecasted O&M expenses through 2028 and in Exhibit A-68 (MAO-2). 8 TR 1627. The O&M expenses in the exhibit were primarily comprised of the cost of circuit conditioning, specifically maintaining capacitors, regulators, and modems. The exhibit provided the number of circuits planned for deployment through 2028 on a per year and cumulative basis, planned O&M expenses for labor, and the anticipated expenditures for circuit conditioning. The forecasted costs apply to non-capital equipment

replacement such as fusing or cabling, and also included communication maintenance such as modem troubleshooting. Distribution equipment must be fully functional in order to make a CVR approach viable. 8 TR 1627-1628.

Mr. Ortiz explained that these costs, as well as the Grid Modernization costs in Case No. U 20134, must be approved in order to operationalize the CVR Program. 8 TR 1628. Mr. Ortiz testified that the CVR deployment and program success is dependent on other electric distribution projects and investments. 8 TR 1628. A core requirement of the CVR Program is communication-enabled field devices. In order to execute the CVR deployment plan, foundational automation deployment programs, such as DSCADA and Regulator Controller Upgrades, must continue receiving support and investment. The Company's investment plan includes spending \$30.6 million for Automation grid capabilities in 2019, \$8 million for DSCADA deployment, and \$4 million for Regulator Controller deployment. CVR is not dependent on all Grid Modernization projects (such as ATR deployment), but those mentioned above are a foundational portion of the CVR Program. 8 TR 1628. The Company therefore requests that, to the extent that any capital costs are not approved in Case No. U-20134, the Commission approve them in this case.

### **3. EWR**

Consumers Energy applied the energy efficiency supply curves provided by GDS to forecast the incremental costs necessary to deliver increased energy savings from 1.5% per year to 2.0% per year in 2021 through 2029 and to 2.25% per year in 2030 through 2040. 8 TR 1583; Exhibit A-63 (TAY-1). The Company projects the cost of conserved energy to average between \$0.0225 to \$0.0301 per kWh throughout the planning period. Exhibit A-63 (TAY-1), line 12. As such, Mr. Ykimoff testified that "the EWR programs represent a low-cost and cost-effective

resource.” 8 TR 1585. The Company requests approval of the incremental EWR costs of \$161,589,035 necessary to increase annual energy savings from 1.5% to 2.0% and to achieve total EWR peak load reductions of 718 MW (incremental 52 MW from the current EWR Plan) by June 1, 2022. 6 TR 259.

The Company will continue to refine the EWR cost projections as part of its EWR Plans filed with the Commission every two years, with its next filing required in 2019. 8 TR 1585-1586. Mr. Ykimoff explained that the EWR Plans include “details on the portfolio goals, a description of each program in the portfolio, energy savings, investment levels, cost-effectiveness test results, portfolio implementation and management details, and [evaluation, measurement, and verification] information.” 8 TR 1585-1586. The Company’s EWR Plan filings will also address applicable changes to the Michigan market that impact energy savings values. 8 TR 1586.

### **C. Retirement Of Karn Units 1 And 2**

Based on the result of the Company’s Medium 4 Retirement Analysis, the Company is recommending the early retirement of Karn Units 1 and 2 on May 31, 2023 and the continued operation of Campbell Units 1 and 2 until the end of their design lives, assumed to be May 31, 2031. As part of the Company’s PCA, the Company plans to replace the capacity lost by these units with the following demand-side resources: EWR, DR, and CVR. The Company’s PCA also presents a plan to recover the unrecovered book balance of Karn Units 1 and 2 and also addresses the execution risks and other impacts related to the proposed retirement.

**1. Unrecovered Book Balance Of Karn Units 1 And 2 And Recovery Proposal**

**a. Unrecovered Book Balance Of Karn Units 1 And 2**

Company witness Cari K. Hurt calculated the unrecovered book balance that would remain under various scenarios related to potential retirement of Karn Units 1 and 2. The scenarios that Ms. Hurt considered included: (i) a baseline assuming the units continue to operate until May 31, 2031 (i.e., the units' currently scheduled retirement date); (ii) a traditional retirement accounting approach assuming that the units retire at May 31, 2023;<sup>15</sup> and (iii) an accelerated depreciation approach assuming a retirement date of May 31, 2023<sup>16</sup>. 8 TR 1494. As a starting point for her calculations, Ms. Hurt noted that the unrecovered book balance of Karn Units 1 and 2 was approximately \$1.2 billion as of December 31, 2017. 8 TR 1494.

Under the baseline scenario – i.e., retirement at May 31, 2031 – the unrecovered book balance of Karn Units 1 and 2, plus decommissioning costs, would be \$914.2 million as of May 31, 2023. 8 TR 1496. Under the early retirement scenario using traditional retirement accounting, the unrecovered book balance of Karn Units 1 and 2, plus decommissioning costs, would be \$778.7 million as of May 31, 2023. 8 TR 1498. Finally, under the early retirement scenario using accelerated depreciation, the unrecovered book balance of Karn Units 1 and 2, plus decommissioning costs, would be \$0 as of May 31, 2023. 8 TR 1499. The derivation of all of these values is shown in Exhibit A-54 (CKH-2).

Ms. Hurt's calculation of the unrecovered book balances of Karn Units 1 and 2 under these three scenarios was used by the Company to evaluate different options for recovery of the

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<sup>15</sup> Under this approach, the unrecovered portion of the plants would remain in the steam plant reserve and be allocated over the remaining lives of the surviving units and the costs to remove the units would be charged to the depreciation reserve account. 8 TR 1496-1497.

<sup>16</sup> Under this approach, the Company would anticipate filing a new electric depreciation case in 2019 and resetting the depreciation rates for Karn Units 1 and 2 to reflect a life ending in 2023. 8 TR 1499.

balances and to arrive at a recommendation for the most reasonable approach to cost recovery as part of the Company's PCA proposal. That analysis and recommendation is discussed in the following section.

**b. Proposal To Recover Unrecovered Book Balance**

Company witness Myers presented the Company's proposal for recovery of the remaining net book value and decommissioning costs of Karn Units 1 and 2. She began by addressing Company witness Hurt's testimony that the estimated remaining net book value of Karn Units 1 and 2 is \$589,853,000, and the estimated decommissioning costs for those units is \$188,880,000. 7 TR 1038. As Ms. Myers explained, the Company proposes to continue to depreciate Karn Units 1 and 2 at the current Commission-approved depreciation rates until base rates are reset in the Company's next electric general rate case. 7 TR 1038. Then, in the Company's next electric general rate case, the actual remaining net book value would be removed from plant-in-service and accumulated depreciation accounts and placed into a regulatory asset. 7 TR 1038. The Company proposes to set an annual amortization rate that allows for the recovery of the remaining net book value and the decommissioning costs by 2031. 7 TR 1038.

As Ms. Myers further explained, the proposal of the Company would operate as follows:

- (i) In the next electric depreciation case, Karn Units 1 and 2 should be removed from the analysis to reflect the fact that those assets will be, or already were, moved to a regulatory asset;
- (ii) The capital expenditures for Karn Units 1 and 2 made after the establishment of the regulatory asset should be recorded to the regulatory asset and the regulatory asset would be increased for decommissioning dollars spent;
- (iii) The amortization of the regulatory asset will include amounts sufficient to collect for decommissioning, but the regulatory asset balance will not include amounts for decommissioning until spent;

- (iv) Once decommissioning costs are incurred, they need to be recorded as an increase to the regulatory asset to offset the decreases caused by the decommissioning piece of the amortization;
- (v) Decommissioning costs would not be recorded in the regulatory asset until actually spent, and would not receive a return until recorded to the regulatory asset; and
- (vi) The amortization established to recover the remaining book value and decommissioning costs acts to lower the regulatory asset balance and also acts as an offset for any decommissioning costs recorded in the regulatory asset. 7 TR 1039.

In reaching this proposal, the Company analyzed five different treatments of the remaining net book value of Karn Units 1 and 2. 7 TR 1040. Those five treatments are:

Traditional Retirement Recovery: under this treatment, remaining book value would remain in rate base and be collected over the remaining life of other similar assets. In the case of Karn Units 1 and 2, similar assets would be the remaining steam plan units (7 TR 1040; Exhibit A-57 (HJM-3));

Regulatory Asset 2023, Regulatory Asset 2031, and Regulatory Asset 2039: All three of these regulatory asset treatments assume that the remaining net book value for Karn Units 1 and 2 will be removed from plant-in-service and accumulated depreciation accounts and recorded in a regulatory asset in the next general electric rate case. The difference between the three regulatory asset treatments is the amortization period. The regulatory asset 2023 would recover the remaining net book value and decommissioning costs by 2023, the regulatory asset 2031 would recover the remaining net book value and decommissioning costs by 2031, and the regulatory asset 2039 would recover the remaining net book value and decommissioning costs by 2039 (7 TR 1040; Exhibit A-57 (HJM-3)); and

Securitization: a securitization scenario is funded completely by debt at an estimated interest rate of 4.98% with estimated Initial Other Qualified Costs of approximately \$15 million for an offering in the year 2023, and estimated Ongoing Other Qualified Costs of approximately \$1.1 million on an annual basis. This scenario also includes decommissioning costs. Including decommissioning costs in the securitization scenarios puts all scenarios on a more comparable basis. If decommissioning costs are not included in a future securitization financing, the Company would need to recover those costs through traditional retirement accounting or through some alternative mechanism approved in a separate proceeding. The securitization scenario utilized an eight-year securitization, from May 31, 2023, to May 31, 2031, which is the period that corresponds with the expected retirement date of the assets as demonstrated in Company witness Hurt's analysis and does not shift costs to customers after the originally-planned retirement date. Because an analysis of the securitization scenario is affected by a number of market-based factors, for which estimates were attempted, and since possible securitization would not occur until mid-2023, it is difficult to accurately estimate the

annual revenue requirement that would result from securitizing the unrecovered book balance of Karn Units 1 and 2 plus decommissioning costs with a high level of precision at this time (all of the estimates would be updated to reflect then-current market conditions if a securitization proceeding is sought at some point in the future). 8 TR 1504-1506).

Ms. Myers' Exhibit A-57 (HJM-3) provides: (i) the total revenue requirements for the five different treatments of remaining net book value for the years 2019 through 2039 (lines 1 through 5); (ii) the NPV of the annual revenue requirement for the five illustrated treatments of remaining book value (lines 6 through 10); (iii) the year-over-year change in revenue requirement for each of the five illustrated treatments of remaining book value (lines 11 through 15); and (iv) the annual revenue requirement change over the 2018 revenue requirement for Karn Units 1 and 2 (lines 16 through 20). 7 TR 1041. Line 16 of Exhibit A-57 (HJM-3) shows that there is a \$23,878,000 increase in revenue requirement in 2020 over the 2018 revenue requirement for Karn Units 1 and 2 for the traditional retirement recovery because MPSC-approved depreciation rates are not currently adequate to recover the remaining book value and decommissioning costs by 2031, which is the Karn Units 1 and 2 previously-assumed retirement date. 7 TR 1041. As Ms. Myers explained, "[e]ven if the units were not retired at an earlier date, the depreciation expense would need to be increased to recover all costs by the 2031 retirement date, thus causing an increase in revenue requirement." 7 TR 1041-1042.

In recommending the regulatory asset 2031 treatment, the Company considered the following:

"First, in order to retire Karn Units 1 and 2 in 2023, the Company needs cost-recovery certainty approved in this proceeding and securitization of the remaining book value cannot be approved in this proceeding. There would need to be a separate securitization application, contested case, and Commission order—the outcome of which is uncertain until well into the future. Second, the Company considered the total cost to customers. Third, the Company considered the net present value of the revenue

requirement for each treatment, and the impact each treatment would have on rates.” 7 TR 1042.

Ms. Myers also presented the following table demonstrating the total revenue requirement and the NPV of the revenue requirements for each of the five illustrated treatments.

(000)	Revenue Requirement	NPV
Traditional Retirement Accounting	1,747,214	1,056,448
Regulatory Asset 2023	1,305,514	1,047,664
Regulatory Asset 2031	1,623,044	1,054,692
Regulatory Asset 2039	1,940,575	1,059,647
Securitization	1,595,282	1,040,864

7 TR 1043.

The Company ultimately proposed regulatory asset 2031 treatment because “it strikes a balance between more closely aligning the collection of the remaining book value of Karn Units 1 and 2 from customers benefiting from the use of the asset and keeping fluctuation rates at a minimum.” 7 TR 1043. Thus, the Company requests the Commission order:

- (i) Approval of regulatory asset treatment of the remaining net book value of Karn Units 1 and 2;
- (ii) To remove Karn Units 1 and 2 net book value from plant-in-service and accumulated depreciation accounts and record the net amount in the approved regulatory asset account in the next electric general rate case;
- (iii) To establish a regulatory asset amortization amount in the next general rate case that will allow for recovery of the remaining net book value and decommissioning costs of Karn Units 1 and 2 by 2031;
- (iv) To allow capital spending for Karn Units 1 and 2 incurred after the establishment of the regulatory asset to be recorded in the regulatory asset and to allow decommissioning cost incurred to be recorded to the regulatory asset; and
- (v) To remove Karn Units 1 and 2 from the analysis of the next electric depreciation case. 7 TR 1045.

## **2. Execution Risks And Impacts Of Retirement**

### **a. Execution Risks**

Mr. Kapala addressed execution risks in connection with the PCA. He testified that Consumers Energy will continue to make capital investments, and incur O&M expenses, at Karn Units 1 and 2 in order to ensure their safe operation. 8 TR 1141. As the units get closer to their early retirement date, the Company will have to evaluate any unexpected maintenance issues that may arise to determine if the economics of the situation would justify performing repairs. For example, if a unit experienced a turbine failure one year prior to the retirement date, the Company would consider both the costs and benefits of replacement and/or repair before proceeding. If replacement and/or repair would result in high costs that could not be recovered before retirement, and replacement energy could be purchased through the MISO market, and replacement capacity could be purchased bilaterally, at a more economic price than the price of replacement and/or repair, then the Company could elect to leave the affected unit in an outage until the retirement date. *Id.*

Mr. Kapala explained that the Company will also need to retain the necessary qualified employees to operate Karn Units 1 and 2 through the retirement date, as well as during the cold and dark time period following retirement. 8 TR 1141. Once the units are certain to retire, employees may begin to seek positions elsewhere in the Company, or externally, which could make the safe operation of the units through the retirement date difficult. An effective employee transition plan can effectively mitigate such risks. 8 TR 1141-1142.

Mr. Kapala also addressed environmental risks in retiring Karn Units 1 and 2. On retirement, the Company will need to bring the units into compliance with environmental regulations (e.g., vacuuming all ash; draining boilers; removing all oil from the machinery).

8 TR 1142. The Company would run the risk of significantly increased clean-up costs if it did not have sufficient time to do the cleaning. The Company would also burn down the coal pile in the final weeks of the units' operation to minimize the amount of coal remaining on site, and would evaluate remediation of the land on which the coal pile sits to determine if that land can be redeveloped for other purposes. 8 TR 1142-1143.

The Company also considered risks related to the future use of the Karn site. 8 TR 1143. When Consumers Energy retired the B.C. Cobb and J.R. Whiting electric generating plants ("Classic 7"), it had enough time to effectively study the divestment of those sites. In the case of Karn Units 1 and 2, the Company would also need time to study different future use options for the site, and to vet different options for both Company-managed demolition and redevelopment and for divestment to a third-party firm to do the work. Because Karn Units 3 and 4 would remain in operation, the Company would have to ensure that any future redevelopment did not create any security risks to the remaining units. *Id.*

Retirement of Karn Units 1 and 2 would also present risk for the local community, namely to the community's tax base and employment base. 8 TR 1143. The Company would help mitigate these risks by assisting in redevelopment of the site to offset the impacts, and by communicating with the community as much as possible to facilitate the effort. *Id.*

The retirement of Karn Units 1 and 2 in 2021 (instead of 2023) would present additional risks. 8 TR 1144. Mr. Kapala testified that a 2021 retirement date for Karn Units 1 and 2 would:

- (i) Not allow the Company sufficient time to implement a safe and responsible transition plan for environmental clean-up, for employee transitions, or for community transitions;
- (ii) Not be feasible to complete necessary separation activities at Karn Units 3 and 4 to ensure their continued operation by May 31, 2021, and thus even if Karn Units 1 and 2 stopped generating energy on May 31, 2021, the units would not be able to be cold and dark until 2022;

- (iii) Greatly compress the timeline for completing separation activity, with a high likelihood of increasing separation activity costs; and
- (iv) Reduce the time for the Company's federal MATS investments to provide benefits to customers. 8 TR 1144-1145.

Mr. Kapala testified regarding the risk that the Company may have to operate Karn Units 1 and 2 beyond 2023 notwithstanding its PCA. He explained that MISO must approve the retirement of a generation unit. 8 TR 1145. MISO would study the Company's retirement proposal to ensure that it does not create transmission reliability concerns, and if it had such concerns, it could require one or both units to remain in operation until a solution is found. 8 TR 1145. If MISO required one or both units to remain in operation, it would designate the unit or units as a System Support Resource, and would ensure that the units fully recover ongoing operating costs by assigning those costs to affected MISO transmission customers through MISO's regulated transmission rates. 8 TR 1145.

**b. Tax, Community, And Employee Impacts**

Mr. Kapala addressed the tax, community, and employee impacts of the PCA. He testified that the Company pays property taxes on Karn Units 1 and 2 that fund local governmental services provided by Hampton Township and Bay County. The units' 2017 taxable value was \$79 million, which was approximately 2.8% of the total taxable value in Bay County and 22% of the total taxable value in Hampton Township. 8 TR 1146. The retirement of Karn Units 1 and 2 in 2023 would also impact employment in the communities in which they are located. 8 TR 1147.

Because retirement of Karn Units 1 and 2 would bring economic transition to the affected community, the Company would help the local community transition to a new economic landscape after retirement through a community transition plan. 8 TR 1147. The Company has 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 would be closely coordinated with a communications strategy to ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company expects to develop a detailed future-use study to analyze specific potential opportunities to redevelop the Karn site. *Id.*

The community communication plan, which the Company began to implement as soon as it announced the planned retirement of Karn Units 1 and 2, notified all affected stakeholders of the retirement proposal. 8 TR 1148. Since under the PCA the Karn Units 3 and 4 would remain in operation, specific redevelopment options for Karn Units 1 and 2 would not be known until the future-use study is finished. 8 TR 1149. The Company would consider options for private redevelopment, as the retirement of Karn Units 1 and 2 may make more of the site, such as the port facilities, available for redevelopment.

The Karn site currently has 240 employees that directly support day-to-day facility operation, with representatives of the Company's Generation Operations, Generation Engineering, Environmental, and other groups. 8 TR 1149. The Company would leverage the lessons it learned from its successful experience in retiring the Classic 7 to develop a retention and separation plan to govern how employees are treated during the decommissioning process of Karn Units 1 and 2. 8 TR 1150.

Once a retirement date for Karn Units 1 and 2 is established pursuant to a Commission order, the Company will implement a retention plan that takes effect 36 months prior to that retirement date. 8 TR 1150. For example, if Karn Units 1 and 2 were scheduled to complete their cold and dark activities by July 1, 2023, then the retention plan would go into effect on July 1, 2020. The retention plan for Operating, Maintenance, and Corporate ("OM&C")

employees was negotiated with the Utility Workers Union of America (“UWUA”) and approved by Company leadership; the Company also developed retention plans for other classifications of employees. As a result, the time needed to fully implement the retention plan would be longer than 36 months. *Id.* The retention plan is a key component of the PCA, as the Company has a strong interest in keeping qualified employees working at Karn Units 1 and 2 through the units’ retirement date to ensure safe and reliable operations. The Company therefore plans to offer retention bonuses to all essential employees who stay at the Karn site for the entire 36-month period. 8 TR 1150-1151.

The separation component of the Company’s plan is also key to the PCA. When Karn Units 1 and 2 are retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. 8 TR 1151. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company’s Salaried Separation Plan. The Company’s Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position. The estimated costs of the retention and separation plan, based on current employment levels and demographics, are up to \$10 million if all employees qualify for the retention bonus and all eligible employees accept a severance offer. The Company intends to find placement for as many employees as possible, thus mitigating the cost of separations. *Id.*

The Company expects that it would need approximately 70 employees to continue operation of Karn Units 3 and 4 until their scheduled retirement in 2030. 8 TR 1152. The rest would be covered by the policy relevant to their classification. The Working Agreement covering OM&C employees guarantees all eligible OM&C employees a position at their current respective wage within 60 miles of the Karn site. The Company's intent that all exempt and non-exempt employees will be offered another position. However, in the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles of their current location, they will be offered involuntary severance in accordance with the terms of the Salaried Separation Plan. The Company has 11 locations within 60 miles of the Karn site. *Id.*

**c. Separation Costs**

Separation costs are the costs that the Company must incur to keep the remaining units at a site functioning when other units retire. 8 TR 1129. Mr. Kapala's Exhibit A-47 (NJK-7), lines 1 through 6, showed the separation activity costs as they were modeled in the IRP, based on the Company's assumptions at the time that it conducted the modeling. Lines 7 through 12 showed the Company's projected separation activity costs at the time that the Company filed this case.

The BAU scenario would not involve any separation activity costs. 8 TR 1129; Exhibit A-47 (NJK-7), lines 1, 2, 7, and 8. If, pursuant to the PCA, the Company retired Karn Units 1 and 2 in 2023, the IRP modeling assumed that the Company would incur \$30,000,000 in separation activity costs at Karn Units 3 and 4 through 2022 to prepare them to operate on a standalone basis. 8 TR 1129; Exhibit A-47 (NJK-7), line 3. If Karn Units 1 and 2 retired in 2021, the Company's IRP modeling assumed \$30,000,000 in separation activity costs at Karn Units 3 and 4, which would be incurred through 2020. 8 TR 1129; Exhibit A-47 (NJK-7), line 5.

Mr. Kapala testified that, subsequent to the IRP model run, the Company determined that it would begin to incur the projected \$30,000,000 in separation activity costs in the event that Karn Units 1 and 2 were to retire in either 2023 or 2021, shortly after approval of its IRP in this case, with work possibly continuing into 2022 in the 2021 retirement scenario. 8 TR 1129-1130. Mr. Kapala provided a detailed description of the separation work that would be involved at the Karn facility. 8 TR 1130-1131.

Mr. Kapala also testified regarding the separation activity costs the Company modeled in the event that it retired Campbell Units 1 and 2 in 2023. 8 TR 1132. In order to allow Campbell Unit 3 to remain operating after the retirement of Campbell Units 1 and 2, the Company would leave the structure housing Campbell Units 1 and 2 in place, and its tripper deck would remain in service. All fuel handling equipment, the tripper deck, and ventilation and heating equipment at the site would have to be repowered from Campbell Unit 3. 8 TR 1134. As a result, the Company would incur incremental major maintenance expenses. Because the structure would remain standing, Campbell Units 1 and 2 would not formally enter the cold and dark period, and pursuing redevelopment opportunities at the site would likely be difficult. *Id.* Mr. Kapala's Exhibit A-47 (NJK-7), lines 4 and 6, showed the costs that the Company's IRP modeling assumes would be incurred at Campbell Unit 3 if both Campbell Units 1 and 2 were retired in 2023, or alternatively 2021. The separation activity costs at Campbell Unit 3 in this scenario would be an estimated minimum of \$10,000,000, incurred through 2023. If only one of the two units were retired, no separation activity costs would be incurred at Campbell Unit 3. 8 TR 1132-1133.

The Company is not requesting Commission approval of separation activity costs in this IRP proceeding. As the Company moves forward with its PCA, it would develop a more

detailed engineering study and construction plans for the separation activity, which it would present to the Commission for approval in a future regulatory proceeding.

**D. Competitive Bidding And PURPA Avoided Costs**

The over-arching objective of the Company's IRP, and the resulting PCA, was to create the most reasonable and prudent means of meeting short- and long-term energy and capacity needs. In accordance with MCL 460.6t, the Company developed an IRP which assessed its existing and future capacity resource portfolio with respect to the capacity requirements of the Company's customers through 2040. This assessment not only included generation resources owned by the Company but also 55 long-term PURPA-based and non-PURPA-based PPAs.

In assessing its generation supply options, the Company proposes a new manner for procuring capacity. More specifically, the Company is proposing that all supply generation be obtained through competitive solicitations. As a result, Consumers Energy is proposing adopting a new methodology for determining the avoided costs that the Company is required to provide QFs under PURPA. The Company proposes utilization of a competitive bidding process to determine avoided costs, which provides the most accurate representation of the costs that the Company actually avoids by purchasing from a QF, provides a reasonable process for the acquisition of capacity, and provides customers with the benefit of competitively priced energy and capacity. Should the Commission not agree with this proposed methodology for determining avoided costs, the Company has developed an alternative, specific avoided cost that is based on a blend of the resources in the Near-term portion of the PCA, specifically EWR, CVR, and DR.

**1. Competitive Bidding Process To Address All Future Capacity Needs**

The Company's PCA represents a shift in Consumers Energy's historical approach to acquiring new supply-side resources. The PCA proposes to maximize EWR and DR programs,

and rely on modular, renewable additions. To take advantage of declining cost curves and achieve maximum flexibility, the PCA proposes to add capacity through smaller, more modular solar projects over a course of years – as opposed to the addition of large electric generation facilities powered by coal or natural gas. 8 TR 1249. To effectuate this strategy, the Company is proposing adoption of a competitive bid methodology to address all future capacity needs.

The Company proposes to utilize a competitive solicitation process to select any new supply-side capacity resources. 8 TR 1251. In preparation of future IRP filings, the Company originally proposed that it would determine if new generation capacity is needed over the next three years and the type(s) of generation that is most reasonable and prudent to procure (e.g., solar, wind, natural gas). 8 TR 1251. EWR measures and energy storage would be evaluated first to determine if they can be implemented to offset any projected generation capacity need. The remaining capacity need would be offered through a competitive solicitation for the technologies that are most reasonable to procure.

In undertaking a competitive solicitation, prior to the filing of an IRP, if Consumers Energy determines that it has a persistent need for new supply-side generation capacity at any point over the first five years that the IRP would address, the Company will initiate a competitive solicitation for a specific amount and type(s) of new generation capacity needed in accordance with MCL 460.6t(6).<sup>17</sup> 8 TR 1252. Independent power producers may submit bids in response to the RFP for the specific type(s) of new generation capacity identified by Consumers Energy for the requested type of generation. 8 TR 1252. The Company would also have an opportunity

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<sup>17</sup> As discussed in Section IV.B.7.a of this Initial Brief, at the rebuttal stage of this proceeding, the Company agreed to Staff's proposal to use a five-year capacity forecasting for determining PURPA capacity obligations. The Company's agreement with Staff's position is conditioned on a finding by the Commission that Company has no PURPA capacity need so long as the Company is implementing the PCA, as approved by the Commission, which includes a competitive bidding process for all future capacity needs.

to submit a bid in response to the RFP. Accordingly, the RFP will be administered by an independent third party. 8 TR 1252. All of the proposals received in the RFP will be evaluated against the cost of utility build options, which would have been submitted by the Company, and the established FCM would be added where appropriate. 8 TR 1252. Proposals will be selected based on the criteria within the competitive solicitation and the attributes of the proposal including, but not limited to, performance standards, contract terms, technical competence, capability, reliability, creditworthiness, past performance, and other applicable criteria.

These competitive solicitations would be undertaken in a similar manner as to how the Company currently undertakes RFPs. Solicitations would be tailored to the specific needs of the Company; and depending on the need identified, proposals could be requested for development asset acquisitions, build-transfer options, partnerships, joint ventures, and/or PPAs. 8 TR 1253. Requesting proposals based on these various options will provide an opportunity to determine what options are the most reasonable and prudent choice for customers.

## **2. PURPA**

### **a. Competitive Bidding To Established PURPA Avoided Costs**

In Case No. U-18090, the Commission issued an Order adopting the Staff's hybrid proxy unit methodology for the determination of the Company's avoided costs. Utilizing this methodology, capacity payments made to QFs were based on a NGCT proxy unit and energy payments made to QFs were based on actual or forecasted Locational Marginal Pricing ("LMP") plus an Investment Cost Attributable to Energy ("ICE") or the variable cost of a NGCC proxy unit plus an ICE. MPSC Case No. U-18090, May 31, 2017 Order, pages 5-6.

The avoided cost methodology approved by the Commission in Case No. U-18090 provides for capacity to be compensated based on the demonstrable capability available from the resource to meet the Company's demand. This provides a significant financial benefit for

potential solar QF resources. Company witness Troyer testified that: “[s]ubsequent to the Commission’s May 31, 2017 Order in Case No. U-18090, the Company began receiving numerous interconnection requests from potential solar QFs due to updating the avoided cost methodology. From May 31, 2017 until May 31, 2018, the Company has received 398 interconnection requests for 1.8 GW of generation ranging in size from greater than 0.15 MW to 20 MW.” 8 TR 1248. The cost associated with 1.8 GW of solar projects that have requested interconnection, based on the current avoided cost rates, is approximately \$263.3 million annually. 8 TR 1248.

The Company’s PCA does not propose constructing new NGCTs or NGCC facilities for supply resources, and avoided costs based on natural gas generation are not representative of the Company’s actual avoided costs. This is significant based on the potential cost impact this could have to customers. The need to reexamine avoided costs has been recognized by the Commission. In this proceeding, the Commission stated:

“When the Commission commenced Case No. U-18090, Act 341 did not exist and PURPA avoided costs had not been reviewed for decades. Now, two-and-a-half years later, the Commission is confronted for the first time with a proposal by a large utility to procure *all* of its capacity needs until 2040 through competitive bidding, with a focus on solar. This is unprecedented. It is highly likely that some of this solar power will be provided by QFs. Even the Joint Intervenors concede that the proxy plant requires updating. Joint Intervenors’ response, p. 1. The Commission does not find any unambiguous language in Sections 6t or 6v that prohibits the Commission from considering the avoided cost, the planning horizon, the size of qualifying QFs, or the contract term in the course of determining whether the proffered IRP is the most reasonable and prudent means of meeting energy and capacity needs. To the contrary, the Commission finds that the comprehensive nature of Section 6t authorizes the Commission to include these considerations. And while the 300-day time limit is enormously challenging, the Commission must concede that, in today’s evolving energy environment, prolonged proceedings are in danger of becoming outdated before they are final.” MPSC

Therefore, the Company requests the Commission's approval to update the methodology and calculations for avoided costs as part of this IRP.

In setting avoided costs, the Company proposes to use two different methodologies for establishing avoided cost rates - depending on whether or not the Company has a capacity need as identified in a capacity demonstration. 8 TR 1251. Under its proposal, the Company would compensate new QF PPAs at the full avoided cost rate when a capacity need exists as determined by the capacity demonstration, and to compensate new QF PPAs at a market-based avoided cost rate when no capacity need exists. 8 TR 1251.

As previously discussed above, Consumers Energy is proposing utilization of a competitive bidding methodology to select any new supply-side capacity resources. QFs up to 20 MW in size will be eligible to participate in these solicitations. 8 TR 1254. However, unlike other independent power producers, QFs under 20 MW will be permitted to submit proposals for any technology, regardless of the technology and any minimum project size requirements specified. 8 TR 1254. The resulting cost of the new capacity resources obtained from this competitive solicitation process will be used as the basis for determining future avoided costs. 8 TR 1251. The proposals submitted through the competitive solicitation would be evaluated, and the highest proposal selected through competitive bidding will be used to establish a capacity clearing price and energy price. 8 TR 1252. These prices will be used as the basis for avoided costs when the Company has a capacity need. 8 TR 1252. For QFs that are awarded contracts as part of the competitive solicitation process, the maximum contract term length will be established in each solicitation to align with the life of the asset. 8 TR 1270.

During an IRP proceeding, the Company will present its capacity demonstration and the results of any competitive solicitation issued prior to the IRP filing. If the capacity need is not filled entirely through the RFP, there will be a capacity need determined by the Commission in the IRP set for the next three years. 8 TR 1253. QFs could fill the remaining capacity need at the avoided cost. If the Company's capacity needs have been met and the Commission determines that the Company's IRP is the most reasonable and prudent manner to meet the Company's energy and capacity needs, no further capacity need exists. At that time, the capacity avoided cost for QFs during the five-year period will be set at Planning Resource Auction ("PRA") rates. 8 TR 1253. If the Commission determines in a final IRP order that the Company has a capacity need greater than presented in the IRP, the Company will conduct another solicitation following the Commission's order to address that incremental need.

The competitive solicitation process will also be used to set the energy portion of avoided costs. Through the solicitation, the Company will see both a capacity and energy price as part of the proposal requirements. In order to provide both a forecast and actual price at time of delivery energy rate, a QF has the option of using the energy price forecast based on the solicitation or the actual LMP rate at time of delivery. 8 TR 1255. If avoided costs are based on a competitive solicitation that requests proposals from a renewable resource, the Company's obligation to buy from renewable QFs impacts the Company's ability to provide renewable energy to customers by displacing resources that would have added to the Company's REC supply. Therefore, forecasted energy avoided costs should be reduced by the market value of the RECs produced by the QF so that the Company can procure an equivalent number of unbundled RECs from the market. 8 TR 1272. Absent a change in the treatment of RECs, customers will be disadvantaged if a QF provides capacity in place of a renewable utility resource or non-PURPA renewable PPA.

8 TR 1272. For QFs that select to receive the actual LMP as their energy rate, the Company should not receive the RECs, because the LMP energy value in the market is not based on the value of renewable energy, it is simply based on energy.

Additionally, the Company is proposing changes to the energy price – providing both an actual and forecasted option for a QF – if no capacity need exists. The first option is an energy avoided cost based on actual MISO LMP for contracts up to 15 years in length. 8 TR 1269. The use of MISO LMPs is appropriate as the rate for energy at time of delivery since, absent the QF, the Company would purchase energy from the MISO market. 8 TR 1256. The second option is a forecast energy avoided cost rate based on a five-year forecast of monthly on-peak and off-peak MISO LMP for contracts up to five years in length. 8 TR 1269. A short-term forecast of the MISO LMP is appropriate to use as the rate for energy because, absent the QF, the Company would expect to purchase energy from the MISO market. 8 TR 1256. The Company proposes the adoption of a shorter term contract for QFs who elected an energy rate based on LMP forecast – since the Company’s forecast of LMPs is more accurate in the near term than in the long term due to shifts in technology and generation fuel prices that affect the market. By limiting the length of contracts offered to QFs that request the forecast LMP, the Company is able to limit financial exposure to customers due to separations between the forecast and actual market trends. 8 TR 1256.

The need for two different contract lengths for actual and forecasted LMPs is based on the different energy rates. This can be seen when looking at the Company’s original RE Plan, filed in Case No. U-15805. In that case, the Company forecasted that average LMPs for 2017 to be \$79.12/MWh. However, the actual day-ahead LMPs for the Michigan Hub in 2017 averaged

\$29.58/MWh. 8 TR 1256. The price differential between the two energy rates exemplifies the need for the different contract terms.

The table below summarizes the avoided costs that the Company intends to make available for new QF contracts based on the energy rate and capacity rate paid under the contract.

	<b>Energy Rate Option 1</b>	<b>Energy Rate Option 2</b>	<b>Capacity Rate</b>
No Capacity Need	MISO Real Time LMP	Forecast MISO Day Ahead LMP	MISO PRA Auction Clearing Price
Capacity Need	MISO Real Time LMP	Competitive Solicitation Results	Competitive Solicitation Results
Existing PURPA QF	MISO Real Time LMP	Competitive Solicitation Results	Competitive Solicitation Results

As discussed in this case, the Company presently has no capacity need. Therefore, Consumers Energy requests that avoided cost rates should be set at the PRA rate and either the MISO LMP or a forecast of LMP energy price. A forecast of IRP marginal prices was sponsored by Company witness Clark on Exhibit A-8 (TPC-6), page 2. As the Company is not in need of capacity, it is reasonable to set the Company's avoided costs at those rates.

**b. Standard Offer Contract**

PURPA provides for the use of a Standard Offer Tariff for QFs of a certain size. The Standard Offer Tariff is designed to help expedite the process for executing contracts with small QFs, and as currently filed by the Company in Case No. U-18090, the Standard Offer Tariff details the program availability, requirements, avoided cost rates, REC treatment, contract term, early termination security, and the process for executing a standard PPA. 8 TR 1274. The Company's proposals in this proceeding would require changes to the Standard Offer Tariff, specifically related to the proposed changes to avoided costs and contract terms.

Additionally, as part of this proceeding, the Company proposes to reduce the size of projects eligible for the Standard Offer Tariff from 2 MW to 150 kW. 8 TR 1274. This change recognizes that the Standard Offer Tariff is most appropriate for small developers and customers that lack the experience and resources needed for larger forays into the electricity generation business. 8 TR 1274. Moreover, the Company's proposed Standard Offer Tariff size aligns with the generator size for customers are eligible to participate in the distributed generation program.<sup>18</sup> See MCL 460.1173.

In reducing the size of projects eligible for the Standard Offer Tariff to 150 kW, the Company proposes offering program participants the full avoided capacity and energy rates regardless of the Company's capacity need. 8 TR 1275. This is because systems of this size are generally owned and operated by customers, and customers typically lack the experience to participate in the competitive solicitation and contract negotiations that are common between utilities and independent power producers. 8 TR 1275. This is important because it is a vast improvement for small developers over what is currently approved.

**c. PURPA Capacity Forecast**

In its November 21, 2017 Order in Case No. U-18090 ("November 21 Order), the MPSC established a 10-year outlook for determining whether Consumers Energy has a capacity need, and established that a Commission order is the necessary mechanism to determine the Company's capacity position. As previously discussed, the Company's base position shows that

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<sup>18</sup> While the Company believes that it is appropriate to align the size of the Standard Offer Tariff with the size of eligible customers to participate in the distributed generation program, the proposed Standard Offer Tariff is not to serve as a substitution for a distributed generation tariff as required by MCL 460.1173. The Company will make its distributed generation tariff proposal in its next electric rate case filing.

no capacity need exists until Planning Year 2030. Thus, under the Company's base capacity position, Consumers Energy does not currently have a capacity need over the next 10 years.

In this proceeding, the Company proposes changing the capacity demonstration period, which relates to the Commission's determination of whether the Company has a capacity need or sufficiency for purposes of paying a full avoided cost under PURPA. 8 TR 1261. The Company's PCA requires an adjustment to the 10-year window utilized for making a capacity determination in order to leverage the PCA's flexible and modular nature. A 10-year capacity demonstration period does not allow the Company to adjust its plans in the future to leverage lower cost technologies or reduced demand. The Company's PCA allows it to provide the right amount of capacity at the right time—but only if the Commission modifies the capacity demonstration period. Company witness Troyer testified:

“If the Commission were to use a 10-year outlook under the PCA, it could conclude that there is a persistent 407 ZRC need for Planning Year 2028 after retirement of Karn Units 1 and 2, as shown in Figure 2 of the direct testimony of Mr. Blumenstock. That need would be filled with approximately 814 MW of solar QFs that have requested new PURPA contracts. Under that scenario, the benefit of being able to take advantage of lower cost technologies and adjusting to demand is lost. It would also have a significant cost to customers by adding \$121 million annually in PPA expenses to the PSCR now, while no need exists for many years. It would also eliminate the need to do any competitive bidding to procure the best resources for customers....” 8 TR 1266-1267.

The Company originally proposed the adoption of a three-year window when making a capacity demonstration finding. Basing the Company's capacity position on a three-year window is reasonable because a three-year forecast of capacity resources and demand better aligns with the reasonable and prudent determination related to cost recovery requested by the Company to implement the PCA in this IRP. 8 TR 1263. Company witness Troyer testified:

“By relying on smaller, modular sources, the Company avoids constructing a large baseload plant and the significant capital investment that goes with it. The PCA allows the Company to adjust its plans in the future should lower cost technologies become available or demand not materialize as forecasted in this IRP. Such adjustments will allow the Company to provide the right amount of capacity at the right time. Such a shift in strategy also allows for a different capacity planning outlook.” 8 TR 1263.

As discussed in Section IV.B.7.a of this Initial Brief, at the rebuttal stage of this proceeding, the Company agreed to Staff’s proposal to use a five-year capacity forecasting for determining PURPA capacity obligations. The Company’s agreement with Staff’s position is conditioned on a finding by the Commission that Company has no PURPA capacity need so long as the Company is implementing the PCA, as approved by the Commission, which includes a competitive bidding process for all future capacity needs. As the Commission has determined that a capacity demonstration must be recognized by a MPSC order, the IRP provides a reasonable framework for making such determinations.

**d. Blended Avoided Cost Rate**

As discussed above, the Company is proposing a competitive bidding process to establish PURPA avoided costs going forward. However, if the Commission elects to use an alternative to what the Company is proposing in this case, Mr. Clark explained that the Company’s avoided costs should be determined using a blend of the incremental energy and capacity resources identified in the IRP over the three-year implementation period (i.e., June 2019 to June 2022). 7 TR 934. Exhibit A-8 (TPC-6), which provides the calculation of the net fixed costs associated with the Company’s PCA through Planning Year 2021, presents the blended avoided cost rate. Mr. Clark specifically detailed the development of this exhibit as follows:

“The Company determined the resources being added specifically identified in the IRP. Those resources’ useful lives were then identified and a weighted average based on summer net demonstrated capability was determined. The energy provided by

each resource was summed and O&M and capital costs were summed. The only resource modeled with capital costs was CVR, so a fixed charge rate for CVR was used to levelize the capital cost associated with the blended resources.” 7 TR 934.

Mr. Clark further explained the blended avoided cost rate would only be used if the Company had a capacity need and clarified that the Company has no need for any supply-side resources over the next 10 years. 7 TR 934-935.

**E. FCM**

Section 6t(15) of Act 341 gives the Commission power to authorize a financial incentive mechanism for PPAs entered after the effective date of Act 341. MCL 460.6t(15). Company witness Michael A. Torrey explained that the traditional regulatory model introduces a bias toward utility asset ownership because utility earnings are directly tied to the growth of the utility’s rate base. 8 TR 1472-1473. In contrast, non-regulated businesses do not have such a bias because non-regulated businesses are able to increase earnings when they are able to lower the cost of goods sold, whether or not the goods are produced through owned assets. 8 TR 1473. Section 6t(15) of Act 341 provides an opportunity to address the bias inherent in the traditional regulatory model for electric utilities by permitting the Commission to approve a mechanism to compensate utilities for entering into PPAs when they might be the lower cost option, thereby breaking the exclusiveness of the current link between asset ownership and earnings. 8 TR 1473.

Furthermore, PPAs generate hidden costs for utilities that should be recognized and accounted for in order to ensure that all of the costs of various alternative options are appropriately considered in making a decision about which new generating resource to procure. Company witness Srikanth Maddipati explains that PPAs have similar financial characteristics as long-term debt, but are not recorded on the Company’s balance sheet. 7 TR 722. Nevertheless, Mr. Maddipati explained that financial analysts, including rating agencies, incorporate PPA

obligations in their analysis of the Company's credit "since the fixed payments, similar to interest payments, reduce financial flexibility and increase the risk of default for the utility." 7 TR 722-723. This practice of recognizing PPA payment obligations as if they were debt on the utility's balance sheet is commonly referred to as "imputed" debt. 7 TR 723.

As a result of the imputed debt recognized by credit rating agencies and other financial analysts, it is necessary for the Company to maintain an increased amount of financial support for the business in the form of equity capital. 7 TR 724. The cost of maintaining the additional equity capital, which is needed to maintain the Company's credit, is borne by customers and investors of the Company. 7 TR 724. Furthermore, without this equity support, the assets used to generate the power sold under the PPA would likely never be built. This is because the debt financing necessary to complete these projects also relies on the equity and creditworthiness of the Company to ensure that there will be a reliable stream of payments over the life of the debt to repay the loans. See, e.g., 7 TR 724-726. Mr. Maddipati testified that, absent a proper compensation mechanism, equity capital providers (i.e., the Company and its customers) will be subsidizing PPA providers. 7 TR 726.

Although the Company has had PPAs for a number of years, the PCA proposed in this case, particularly the competitive bidding proposal for all new generation assets, increases the likelihood that a significant portion – in fact, potentially all – of the Company's generating portfolio in the future could be comprised of PPAs instead of Company-owned assets.

Mr. Torrey testified:

“[A] competitive bid methodology presents significant risks to the Company's ability to attract capital investment for needed infrastructure investments and provide sustainable returns to investors unless there is an incentive for the Company to enter into PPAs. Otherwise, the Company's credit ratings could become stressed and the Company would have a bias towards constructing

its own projects to own, or entering into ‘build-transfer’ agreements for the ownership of projects, whereby a developer builds the project and then sells it to Consumers Energy.” 8 TR 1474.

Given the issues discussed above, it is imperative that the Commission implement an incentive mechanism to help ensure it will be financially possible for the Company to execute the plans set forth in this IRP. In fact, failure to implement a meaningful and adequate FCM could seriously threaten the financial stability of the Company if all or a significant portion of its generating portfolio were comprised of PPAs as a result of competitive bidding. Mr. Torrey explained that the Company needs to be assured that it will have an appropriate incentive in order to be willing to move away from the traditional utility model. 8 TR 1481. If the Company’s proposed FCM is not approved in this proceeding, the Company does not propose to go forward with the competitive bidding of future capacity needs. 8 TR 1474.

Accordingly, the Company requested that the Commission approve a FCM pursuant to the authority granted under MCL 460.6t(15). The Company’s proposed FCM has been carefully designed to address the issues described above and to align the interests of the Company and its customers in order to enable the appropriate comparison and selection of alternative options for new generating resources consistent with the PCA. The design and application of the Company’s proposed FCM are described in more detail below and should be approved as proposed.

### **1. Description Of FCM**

Company witness Maddipati described the design of the FCM. He testified that the FCM would calculate a fixed charge determined at the time a PPA is approved by the Commission and would apply to the life of the PPA. 7 TR 727. Mr. Maddipati testified that the fixed charge would be calculated as follows:

- “(a) Calculate the equity required to offset imputed debt for each year of the PPA. The imputed debt will equal the NPV [i.e. the Net Present Value] of the PPA payments multiplied by 25% (PPA Imputed Debt = Required Equity Capital);
- “(b) Multiply the required equity capital resulting from the calculation in a) by the Company’s authorized ROE from its most recent general electric rate case for PPAs supported by non-renewable generation assets or the authorized ROE in its Renewable Energy Plan for PPAs supported by renewable generation assets; and
- “(c) Gross up the results from the calculation in b) by the factor used for calculating the Company’s revenue requirement in its most recent electric rate case.” 7 TR 727.

The 25% factor applied in the first step of the FCM calculation corresponds to the methodology utilized by Standard & Poors (“S&P”) to calculate the amount of imputed debt to assign to Consumers Energy as part of its credit rating process. 7 TR 723. Mr. Maddipati testified that S&P has the most explicit methodology for calculating imputed debt. 7 TR 723.

The result of Mr. Maddipati’s proposed calculation would be a levelized cost for the FCM applied over the life of the PPA. Mr. Maddipati explained the rationale for creating a levelized cost as follows:

“As the PPA reaches maturity, the amount [sic] of imputed debt decreases and therefore the required compensation would also decrease, which is akin to a bond amortizing. Similarly, if the utility had self-built its own generation, the revenue requirement would also decrease over time to reflect the depreciation of the asset. However, most PPAs are negotiated to have a fixed price or escalating price; therefore, creating a levelized cost as a compensation mechanism would align with the typical structure of a PPA. To calculate the levelized cost, the NPV of the compensation payments is discounted at the authorized ROE and then levelized using the Company’s WACC [i.e. its weighted average cost of capital rate].” 7 TR 728-729.

Therefore, it would not make sense to use a declining cost methodology for calculating and applying the FCM.

Mr. Maddipati sponsored Exhibit A-52 (SM-1), which illustrates the calculation of the FCM for a hypothetical 10-year PPA with a fixed \$60/MWh PPA payment over the life of the PPA. The FCM would result in a fixed charge of \$8.28/MWh in this example. 7 TR 731. Mr. Maddipati notes the simplicity of the calculation due to the fact that all of the necessary inputs would be readily available at the time a PPA is signed. 7 TR 731. He explained that most of the inputs would already be known as a result of the Commission's Order in the Company's most recent electric rate case, Case No. U-18322. He testified, "In fact, the only inputs that would be subject to consideration are the PPA payments and length which will be pre-determined by the PPA agreement or the Company's avoided cost for PURPA contracts." 7 TR 731.

Section 6t(15) of Act 341 requires that any PPA incentive mechanism approved by the Commission must not exceed the Company's Weighted Average Cost of Capital ("WACC"). MCL 460.6t(15). Mr. Maddipati demonstrated mathematically that, using inputs from the Company's most recent electric rate case, the resulting incentive is guaranteed to be lower than the Company's WACC. 7 TR 729-730. Using the current inputs from the Company's most recent electric rate case, the Company's incentive, as a percentage of the NPV of the PPA payments would only be 3.35% as compared to the Company's current WACC rate of 5.89%. 7 TR 729-730. Since the rate applied will never exceed the WACC rate, the resulting incentive cannot exceed the WACC.

Company witness Torrey testified that, once calculated, the FCM should be recovered through general base rates as part of the Company's electric rate cases. 8 TR 1475. Mr. Torrey also requested that, when the start or termination of a PPA subject to the FCM and general rates are not aligned (i.e., when a PPA starts or terminates between electric rate case orders issued by

the Commission), the Company should be permitted to use deferred accounting to address the FCM incentives until rates are once again reset in the Company's next electric general rate case. 8 TR 1475-1476. The Commission should approve the Company's recommended FCM design.

## **2. FCM And Competitive Bidding Process**

The Company's proposed FCM is intended to be applied to new PPAs that have not previously been approved by the Commission. As discussed above, the FCM is a calculation that contains several inputs that change over time. 8 TR 1275. For each new contract, the Company will request approval of an FCM specific to each new PPA. The Company's Application for approval of the PPA will include the applicable inputs for the FCM calculation to reflect the appropriate level of compensation at the time the PPA was filed for approval with the Commission. 8 TR 1275-1276. The FCM would be applied over the full contract term.

Company witness Troyer addressed how to apply the FCM to the PPA. Mr. Troyer testified that:

“As the Company books the generation and associated expense according to the terms of the PPA on a monthly basis, the FCM will be added to the total PPA expense booked for the month. The counterparty will receive the compensation associated with the rates included in the PPA and the Company will retain the financial compensation. The FCM is determined on a \$/MWh basis, so the Company will multiply the approved FCM for the PPA by the amount of generation booked for the month, including any prior period adjustments.” 8 TR 1276.

The Company would request recovery of the costs related to the FCM through base rates. 8 TR 1276.

**F. Impact Of The PCA On Average Customer Rates And Incremental Revenue Requirements**

Company witness Myers also presented information regarding the rate impacts for the PCA. Exhibit A-55 (HJM-1) provides an analysis of the rate impacts for the PCA. Overall, Exhibit A-55 (HJM-1) demonstrates that:

“the PCA holds projected customer rate increases to a CAGR through 2039 of less than 0.7%. The annual increases in revenue requirement vary over the time period, but in 20 of the 21 years they are less than 2%.” 7 TR 1034.

The incremental revenue requirement on Exhibit A-55 (HJM-1), line 1, represents the difference in revenue requirement between the BAU IRP scenario and the PCA. 7 TR 1034.

Ms. Myers explained the calculation of the incremental revenue requirement as follow:

The incremental revenue requirement is calculated by summing the change in return on rate base, depreciation expense, and property tax caused by differences in capital spending between the business-as-usual scenario and the PCA. The difference in Operation and Maintenance (‘O&M’) expense and change in PSCR costs is then added to the sum of the capital spend impacts for the total incremental revenue requirement. 7 TR 1034.

Because the incremental revenue requirement, as presented, is intended only to isolate the difference in revenue requirement from the BAU scenario and the PCA, the incremental revenue requirement, as presented in Exhibit A-55 (HJM-1), line 1, does not include all expected changes in revenue requirement through 2039. 7 TR 1035. Additionally, because the PCA does not alter the need to recover the remaining net book value of Karn Units 1 and 2, the incremental revenue requirement, as presented in Exhibit A-55 (HJM-1), line 1, also does not include the revenue impacts of collecting the remaining net book value of Karn Units 1 and 2. 10 TR 1035. A pretax rate of return of 7.32% was used in calculating the incremental revenue requirement and represents the approved pretax rate of return from the Company’s most recent electric rate case

Order (Case No. U-18322), adjusted to incorporate a 21% federal income tax rate, consistent with Tax Reform. 7 TR 1036.

Ms. Myers' Exhibit A-55 (HJM-1), line 2, provides a percentage increase in revenue requirement and is calculated by dividing each year's incremental revenue requirement by the base rate and PSCR revenue requirement from Case No. U-18333, adjusted to incorporate a 21% federal income tax rate plus the revenue requirement associated with the currently billed EWR surcharge. 7 TR 1036. Additionally, lines 4 through 6 of that exhibit provide the cents/kWh impacts of the incremental revenue requirement. 7 TR 1036-1037. Line 9 of the exhibit provides the present value of the incremental revenue requirements of the PCA, which was calculated using a discount rate of 7.32% (representing the pretax rate of return approved in the most recent electric rate case adjusted to include a 21% federal income tax rate consistent with Tax Reform. 7 TR 1037.

Ms. Myers' Exhibit A-56 (HJM-2) provides an analysis of the rate impacts for the alternate course of action. 7 TR 1037. As Ms. Myers explains in her direct testimony,

“[T]he CAGR for the alternate scenario is 0.83% which is higher than the CAGR of the PCA. The alternate course of action would also result in a one-time increase of over 8% in the year 2031. Thus, from a customer rate impact perspective, the PCA is more reasonable than the alternate course of action.” 7 TR 1037.

Finally, Ms. Myers' Exhibit A-58 (HJM-4) provides rate impact analysis for eight different Medium 4 retirement scenarios. 7 TR 1038. The calculations included in this analysis follow the same methodology as used for the PCA. 7 TR 1038.

#### **IV. INITIAL RESPONSE TO STAFF AND INTERVENORS**

The Company disagrees with many of the proposals included in the testimony filed by the parties in this case. The Company, in this Initial Brief, addresses several anticipated areas of dispute and relies upon the record and evidence in support of its requested relief. As discussed

below, the record evidence in this case supports the approval of the Company's entire PCA. All arguments to the contrary should be rejected, and the Commission should issue an order granting the Company's requested relief in full.

**A. Modeling**

**1. Base Capacity Position**

SEIA witness Kevin M. Lucas, MCV witness Emily Medine, and ELPC/MEC witness Douglas B. Jester take issue with the Company's Baseline Capacity Position. Mr. Lucas posits that it will be difficult for the Company to successfully deliver on its demand-side resource targets and replacement plan for the Palisades PPA. Due to this alleged difficulty, Mr. Lucas suggests that the Company's capacity position could be supplemented with an additional 1.8 GW of PURPA QF solar resources. 8 TR 1972-1973. Furthermore, Mr. Lucas, Ms. Medine, and Mr. Jester all point out that the FERC has not granted the necessary approvals to allow Amendment No. 2 to the Filer City PPA to move forward and therefore the capacity expected to be provided by this resources is at risk. For the reasons discussed below, the Commission should reject the positions of Mr. Lucas, Ms. Medine, and Mr. Jester regarding the Company's Baseline Capacity Position.

**a. Risk Of Baseline Capacity Position And Purchase Of Additional PURPA QF Solar**

Mr. Lucas' attempt to create the impression that significant effort is required by the Company to deliver the capacity additions identified in the PCA between 2018 and 2023 is without merit. Mr. Lucas fails to consider that the vast majority of these capacity additions which the Company is proposing to rely on in the Base Capacity Position are projects that are well underway and therefore not subject to high execution risk. 7 TR 939. Mr. Clark provided a

detailed explanation as to the low execution risk related to each of the Company's assumptions in its Baseline Capacity Position.

Mr. Clark first addressed the demand-side resources assumed in the PCA and explained that the past two years of energy efficiency performance demonstrate the Company's ability to deliver the savings increases assumed in the PCA. In 2017, the Company began ramping its energy efficiency program from 1% savings annually to 1.5% savings annually. 7 TR 940. This increase was accomplished successfully and demonstrates the knowledge and ability of the Company's demand-side program managers to understand how to successfully ramp their programs to deliver the higher levels planned. Similarly, Mr. Clark explained that the Company's ability to ramp DR at the levels identified in the PCA is proven by the performance between 2016 and 2018. 7 TR 940. Furthermore, while there is risk related to the implementation of CVR, due to the fact that this is a new program, the Company has mitigated this risk by limiting reliance on CVR to only 56 ZRCs. 7 TR 940.

The Company is also relying on improvements to its existing generating resources which carry a low risk. Mr. Clark explained that the capacity delivered through improved performance at existing generating is based in part on recent investments and workforce development at Karn Units 3 and 4. 7 TR 940. Moreover, the Company is relying on capacity improvements delivered by the Ludington upgrade project that began in 2013. Mr. Clark testified that the overhaul and upgrade of each of the six Ludington units is nearly complete and also that the increased capability from each of those units is proven by the upgrades already completed on Ludington Units 2, 4, 5, and 6. 7 TR 940.

In addition to relying on improvements to existing resources, the Company is relying on PURPA QF capacity as required to be purchased by the Commission. Consistent with the

Commission's direction in its May 31, 2017 Order in Case No. U-18090, the Company's PCA assumes that all QFs 20 MW and below, which currently have PPAs with the Company, will sign new PPAs once their current agreements expire. 7 TR 940. This is a low risk assumption because these facilities are currently supplying energy and capacity to the Company and have also expressed a desire to continue to contract with the Company. Furthermore, the Company is relying on 150 MW of new PURPA-based PPAs, as directed by the Commission in its February 22, 2018 and October 5, 2018 orders in Case No. U-18090. 7 TR 941. Mr. Clark explained that there is a substantial development risk related to these resources but contracting for 150 MW of new solar resources carries a significantly lower risk than SEIA witness Lucas' proposal that the Company immediately contract with 1.8 GW of new QF solar resources. 7 TR 941.

Finally, the Company is relying on 550 MW of new wind generation, in accordance with its RE Plan, which carries a relatively low execution risk. 7 TR 941. Mr. Clark explained that the Company is working to deliver this wind generation through build-transfer agreements and development acquisition projects which require less responsibility for construction of the asset for the Company, as the developer bears the construction risk. 7 TR 941. The Company's past experience developing similar projects, such as the Lake Winds and Cross Winds Energy Parks, and the motivation to achieve 100% of the PTC, create confidence that these projects will be delivered as assumed. 7 TR 941.

Therefore, Mr. Lucas' attempt to portray the Company's Baseline Capacity Position as risky and recommendation to purchase additional QF solar resources should be rejected. Mr. Lucas is also incorrect that the procurement of an additional 1.8 GW of QF solar resources, in advance of the Company's proposed competitive bidding process, reduces risk because:

(i) these projects have a head-start on newly developed projects; (ii) Consumers Energy would not have primary responsibility for bringing these projects online; and (iii) these would allegedly protect ratepayers from construction and cost overrun risk. 8 TR 1973. As established above, the capacity additions identified in the PCA are either not newly developed or do not rely on Consumers Energy having primary responsibility for bringing them online. 7 TR 942. Furthermore, the Company has sought to limit ratepayer risk from construction and cost overruns through the appropriate use of build-transfer agreements. 7 TR 942.

**b. Amended Filer City PPA**

In response to testimony from Mr. Lucas, Ms. Medine, and Mr. Jester concerning Amendment No. 2 to the Company's PPA with Filer City, Mr. Clark explained that, on August 3, 2018, FERC denied Filer City's application for recertification of the Filer City cogeneration facility as an existing cogeneration QF pursuant to PURPA. 7 TR 943. Since Article 1 of Amendment No. 2 requires that FERC approve the recertification of the converted Filer City Plant as a QF, Amendment No. 2 has been rendered void *ab initio*. 7 TR 943. This means that the additional ZRCs assumed for the converted Filer City Plant will not be available.

The cancellation of Amendment No. 2, as described above, will not have a material impact on the Company's PCA. Mr. Clark explained that the Company's PCA was developed in a way to mitigate the risk of a capacity shortfall should some planned capacity resources not materialize. 7 TR 943. If everything were to develop as planned in the PCA, absent the additional capacity that would have been provided by the converted Filer City Plant, the Company would now experience a small shortfall in 2031 and 2032. 7 TR 943. Exhibit A-99 (TPC-7) reflects the Company's capacity position without the capacity provided by the converted Filer City Plant. Mr. Clark explained that it is possible that this small shortfall in 2031 and 2032

may never materialize as a result of load forecast inaccuracy or changes in performance of existing generation or demand-side programs. 7 TR 943. If this small need is still projected at the time of the Company's next IRP, this issue will be addressed at that time. 7 TR 943.

## **2. Demand Forecast**

### **a. Response To SEIA**

In his direct testimony, SEIA witness Lucas calls into question the Company's forecasts for Electric Vehicle ("EV") sales and usage. Mr. Lucas, using the EIA's AEO 2018 ("AEO 2018"), indicates that he considers the Company's forecasts to be significantly lower than those reflected in AEO 2018, saying, "[g]iven that there are nearly 2 million customers in CE's territory, and when considered in the context of these reports and the rapid evolution of the transportation sector, CE's EV forecast is not credible." 8 TR 1961-1963. Mr. Lucas's reliance on the AEO 2018 admittedly "include[s] more than just CE's territory." 8 TR 1960. While SEIA considers AEO 2018 to be "instructive," it is not an accurate reflection of Consumer's Energy's electric service territory, the current regulatory landscape, or the current infrastructure surrounding EVs and Plug-in EVs ("PEVs") within the Company's electric service territory; it thus, should be rejected by the Commission.

As Mr. Breuring indicated in his direct testimony, the Company evaluated and forecast electric deliveries related to EVs, Plug-in Hybrid EVs, and/or Battery EVs. 8 TR 1653. Mr. Breuring explained the Company's projections surrounding EVs, PHEVs, and BEVs as follows:

"The BAU deliveries forecast does not account for significant growth of EVs at this time. Data acquired from Alliance of Automobile Manufacturers (2018), shows 2017 statewide Michigan-registered EVs number around 12,500 to 15,000, with approximately 4,000 of those located in the Company's electric service territory (2016 Michigan Secretary of State registrations).

With an estimated 8,000,000 total registered vehicles in Michigan, EVs account for a mere 0.2% of total registered vehicles in the Company's service territory. Because of the growth potential for EVs in the state of Michigan, the Company continues to monitor developments in this industry, as well as projections by third-party data management companies (i.e., IHS Markit, Energy Information Administration, and Bloomberg New Energy Finance)." 8 TR 1654.

The Company, thus, evaluated Consumers Energy territory-specific data as it relates to the Company's forecast of EV growth. Further, the Company's BAU forecast is based on the current regulatory landscape, as well as current infrastructure surrounding EVs and PEVs within the Company's electric service territory. 8 TR 1663. As Mr. Breuring further explained:

"dramatic increases in the EV industry, as projected by some outside agencies, is not intended to be part of the Company's BAU forecast at this time. The Company realizes that the potential for EV growth exists, however, this growth is highly dependent on regulatory and infrastructure factors that are yet to materialize. Factors related to battery life, extension of federal tax credits, increased number of charging stations within the Company's service territory, as well as customer behavior and acceptance of EVs over internal combustion engine vehicles, among others, will impact projected EV consumption." 8 TR 1663.

Because the regulatory and infrastructure factors are "yet to materialize," SEIA's use of forecasts that demonstrate dramatic increases in the EV industry, that are not specific to the Company's electric territory, are misplaced, premature, and should be rejected by the Commission.

Similarly, Mr. Lucas criticizes the Company's embedded demand-side management reductions found in the Company's adjusted sales forecast as they "substantially exceed those included in the AEO 2018." 8 TR 1963. Mr. Breuring disagrees with this criticism, saying "[t]he DSM projections used in the Company's forecasts are derived from the Company's Demand Response Group and Energy Waste Reduction ('EWR') group, which is substantially supported by Company witness Mark A. Ortiz, who supports the Company's Conservation

Voltage Reduction Program, and Company witness Theodore A. Ykimoff, who supports the Company's increased EWR." 8 TR 1664. Again, SEIA's reliance on AEO 2018, which is generalized and not based on Company-specific data, is not accurate and should be rejected by the Commission.

**b. Response To Staff**

Staff witness Olumide O. Makinde presented testimony regarding Staff's position with the Company's peak demand and energy sales forecasts and associated methodologies. Specifically, Mr. Makinde expressed Staff's concern and recommendations regarding time interval granularity of regressions data and evaluation methodologies. Mr. Makinde first recommended "that the company consider using hourly, or possibly daily, data for the weather and historical energy sales variables." 9 TR 2641. As Mr. Breuring explained, the Company cannot meet this request. He explained:

"Though the model may or may not be enhanced by using more granular data, the Company cannot meet this request. The models use 15 years of historical data that has always been recorded at the monthly level. Even though the Company has smart meters deployed, the Company would need 15 years of hourly data to build a regression model that would meet this recommendation. Furthermore, the Company's models and current modeling processes have historically produced highly accurate results which are well within regression modeling industry standards." 8 TR 1664.

Additionally, in Mr. Makinde's direct testimony, he "recommends the Company consider conducting and reporting the MAPE evaluation on the monthly peaks to ensure the forecasts are within an acceptable range for all months and not only the peak day." 9 TR 2642. As Mr. Breuring explained, this is not a reasonable request because:

"[t]he peak demand regression model generates monthly peaks and the model evaluation returns a MAPE for the entire model. To produce a MAPE for each monthly peak would require the

development of 12 monthly regression models that simply forecast the individual monthly peaks and would require significantly more work and possibly generate inconsistent results.” 8 TR 1664-1665.

Because, as explained by Mr. Breuring, Staff’s recommendations are not reasonably achievable by the Company, Staff’s recommendations should not be accepted by the Commission.

### **3. Natural Gas Price Forecast**

Staff witness Roger A. Doherty states that Staff does not entirely agree with the Company’s natural gas price forecast and discusses an alternative forecast methodology which uses market futures to develop a short-term forecast, a simple average of the three long-term price forecasts for the long-term forecast, and the linear blending between the near-term and long-term forecasts to develop a mid-term period.<sup>19</sup> 9 TR 2625-2626; see also Exhibit S-4.1. However, Mr. Doherty ultimately concludes that the Company’s natural gas price forecast is “reasonable” but “more in line with a low gas price scenario than business as usual.”<sup>20</sup> 9 TR 2628. The following addresses Mr. Doherty’s discussed alternative forecast methodology.

Company witness Gallaway explained that the Company previously used the same calculation that Mr. Doherty discussed, but because of accuracy concerns, modified its forecasting approach to what it has proposed in this case. 8 TR 1693. Mr. Gallaway further explained that the Company believes that the Company’s forecast, which utilizes the average of the monthly values for each respective year of the New York Mercantile Exchange (“NYMEX”) future prices for the near-term (2017 through 2022), and an average incremental increase of the three long-term price forecasts applied to the years following the five-year futures contracts

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<sup>19</sup> ABATE witness Jeffrey Pollock also addresses the Company’s natural gas price forecast and refers to the Company’s forecast as the “least inaccurate of the published forecast in this proceeding.” 8 TR 2129. Mr. Pollock did not recommend an alternative forecast.

<sup>20</sup> Mr. Doherty indicates that the Company’s fuel price forecast has met the requirements of the law and the Commission’s MIRPP, as approved in Case No. U-18418. 9 TR 2622-2624.

traded on the NYMEX for the long-term (2023 through 2040), provides a better projection of near- and long-term prices than Staff's alternative. 8 TR 1693. Mr. Gallaway also presented extensive detail as to the development of the Company's natural gas price forecast as follows:

“the Company creates a composite fuel price forecast taking into account the expertise and opinions of different well known industry forecast sources as well as the market forwards which are reflective of actual transactions. A problem in using third-party natural gas forecasts has to do with the age of the forecast. Major third-party forecasters perform research and update their forecast only once per year. The natural gas prices in those forecasts are typically reflective of the market prices at the time the forecasts were published. Since natural gas prices can be very volatile in the market, there can be large variations in forecasted prices simply because of the time of year the forecast was published. To mitigate this concern, the Company uses the average incremental increase and applies it to the latest five-year futures contract traded on NYMEX to allow the Company to rebase the vintage third party forecast to the current period. This “rebasing” has a built-in assumption that if all the third-party forecasters prepared and published their forecast at the same time, the earlier years would be nearly identical and would vary in the out years only due to a different escalation assumption. It is accepted and understood that this methodology may not converge to the average of the vintage third-party forecasts, as its intent is to simulate an update of each third party forecast by rebasing each forecast to the same starting point.” 8 TR 1692-1693.

Although the Company does not agree with the use of Staff's discussed methodology for forecasting natural gas prices, the Company uses this methodology to forecast oil and coal prices. The Company believes that this is a reasonable methodology for forecasting oil and natural gas prices because these commodities are less volatile than natural gas. 8 TR 1693.

#### **4. Resource Selection and Projected Operation**

##### **a. Energy Storage Modeling**

Staff witness Cody S. Matthews indicated that while Staff is generally supportive of the Company's planned renewable and DR resources, Staff believed that the Company did not adequately consider storage as a potential technology to complement other proposed resources

prior to 2032. 9 TR 2815-2816. Staff noted that the Company's model was unable to combine renewables and battery storage for co-optimized dispatch, and recommended that "the Company rework its modeling to include the co-optimized dispatch of renewables and battery storage." 9 TR 2819. Consumers Energy agrees that its current modeling only considered the energy and capacity value that storage provides, and the Company is in the process of determining ways in which to model other benefits of storage. 6 TR 499.

Consumers Energy expects to be able to quantify additional potential benefits of storage as the Company continues to integrate its electric supply, distribution, and transmission planning. 6 TR 499. The Company also plans to begin using Aurora capacity expansion tools for its modeling, which offers features not currently available in Strategist and which the Company anticipates will provide for an expanded analysis of energy storage in future IRPs. 6 TR 499. The PCA's flexibility will also permit the Company to more frequently analyze storage and any associated value-added products. 6 TR 499-500.

**b. Meeting Peak Demand And Energy Requirements Through The PCA**

ABATE witness Jeffry Pollock argued that a risk associated with the PCA is the substantial amount of EWR, CVR, and DR, which would represent an increasing amount of the Company's PRMR. 8 TR 2126. Company witness Walz explained that PRMR represents the Company's demand plus reserves expected to occur on the highest peak load day of the year, with the RMR representing the difference between the coincident peak demand and the total PRMR. 6 TR 491. Mr. Pollock expressed concern that the Company's entire reserve margin (or RMR) would be provided by DR programs by 2031. 8 TR 2127. However, the Company does not allocate the planned amount of DR, or any other resource, to the Company's RMR; rather, the Company provides a pool of resources that collectively serve the entire PRMR (peak demand plus reserves). 6 TR 492.

Attorney General witness Sebastian Coppola expressed concern with the increased amount of solar generation in the PCA, particularly because “solar generation drops off dramatically as the sun sets while power demand still remains high.” 8 TR 2366. The Strategist modeling that the Company performed addressed Mr. Coppola’s concern. The modeling that the Company used to develop the PCA selected a least-cost portfolio from the co-optimization of capacity *and* energy requirements. 6 TR 492-493. Thus, the modeling considered and selected resources (such as solar generation) based on their ability to provide the lowest cost capacity *and* energy. 6 TR 493. In addition, the Company demonstrated that, when combined with historical levels of market purchases, sufficient resources exist in the PCA to meet peak demand in January 2039 even absent any solar generation. See Exhibit AG-12.

**c. Incremental Wind In The PCA**

The PCA includes 525 MW of wind capacity by 2021 as part of the Company’s RE Plan, and an additional 25 MW not currently proposed in the Company’s RE Plan to be online by 2021. 6 TR 493. MEC witness Tyler Comings stated that the model selected a significant amount of new wind if the Company retires Campbell Units 1 and 2 (in addition to Karn Units 1 and 2) in 2023, and suggested that the Company could procure wind in advance of that date at reduced cost because of a higher PTC. 8 TR 1860. ELPC witness Joseph M. Daniel also argued that the Company’s modeling limited realistic consideration of incremental wind resources. 8 TR 2280.

The Company did not include incremental wind in the PCA for several reasons. First, the Company was concerned about the feasibility and cost-effectiveness of additional wind in Michigan because of the wind expansion already planned as part of the Company’s RE Plan, recent moratoriums on construction of wind in Huron County, and lower capacity factors of wind in the central region. 6 TR 452. Second, the Company identified several non-economic risks

with the expansion of wind in Iowa, including that: (i) wind produced and sold in Iowa would provide no RECs necessary to comply with Act 342's REC portfolio standard; (ii) wind project development in Iowa provides no economic benefit in Michigan; (iii) the Company does not have experience working with local regulations, requirements, and communities in Iowa to develop and operate wind facilities; and (iv) the Company does not have experience with state regulatory bodies in Iowa. 6 TR 453.

Company witness Clark also explained that the model selected 3.2 GW of out-of-state wind in 2023 because the energy value of the wind effectively buys down the cost of the capacity. 7 TR 923. However, constructing 3.2 GW of out-of-state wind represents a high risk in a number of scenarios, including where energy prices do not materialize, energy cost spreads between in-state and out-of-state are greater than forecast, materially higher transmission costs are incurred to construct the wind, or greater capacity price separation between MISO LRZ7 and the zone where the out-of-state wind is constructed. 7 TR 923. The Company also determined that constructing an additional 3.2 GW of wind in Iowa in 2023 would not be feasible. 7 TR 923-924. While the Company could have included a reduced amount of out-of-state wind in the PCA, given that the model selected wind in the Near-term, the Company was not confident that it could obtain out-of-state wind development expertise in sufficient time to realize the costs modeled. 7 TR 924. As a result, the Company reasonably selected in-state solar resources in the PCA instead of out-of-state wind. 7 TR 924.

As detailed in this Initial Brief, the Company does not support the retirement of Campbell Units 1 and 2 in 2023, and thus the additional wind generation identified by Mr. Comings is not necessary. The record in this case fully supports the level of wind capacity included in the PCA. However, as a result of the flexibility inherent in the PCA, the Company may consider wind

resources in place of solar resources if cost-competitive wind resources become available in Michigan. 7 TR 924.

**d. Mix Of Market Purchases And New Resources**

MEC witness Comings contended that the Company's modeling should have allowed for a "blend of both market purchases and new resource replacement." 8 TR 1835. However, under the Commission-approved capacity demonstration process and requirements, each Load Serving Entity ("LSE") is limited to planning to purchase 5% of the LSE's total PRMR requirement in the MISO PRA. See Capacity Demonstration and Requirements for Planning Years 2022 through 2023 and 2023 through 2024<sup>24</sup>, page 7, which was approved by the Commission in its September 13, 2018 Order in Case No. U-20154. The Company intends to use this 5% of PRA purchases to mitigate risk and allow for minor adjustments in capacity position, and does not intend to rely on PRA purchases as a definitive resource. 6 TR 496. Thus, the Company did not develop a portfolio that allowed for a mix of significant PRA purchases and new resource additions. 6 TR 496.

MEC modeled the replacement of Campbell Units 1 and 2 in 2023 with capacity purchases. 8 TR 1819. The 475 ZRCs selected in 2023 to replace Campbell Units 1 and 2 is beyond the 5% limit established by the Commission. 6 TR 497. In 2023, a purchase of 475 ZRCs amounts to 5.97% of the projected PRMR of 7,958 ZRCs, and thus is not permitted under the Commission's capacity demonstration requirements. 6 TR 497. The Company would not be permitted to purchase 475 ZRCs from the PRA in 2023 to replace Campbell's Units 1 and 2 capacity.

The modeling conducted by MEC witness George W. Evans also omitted certain costs in his market purchase portfolios for the Campbell retirement scenarios. 6 TR 497. In years where the MISO market region has minimal surplus capacity, purchases of capacity would be made

possible by new capacity additions. 6 TR 498. Similar to the new capacity additions added to the Company's supply portfolio, these capacity additions would be expected to result in a network upgrade cost. 6 TR 498. Mr. Evans did not include the approximately \$54/kW network upgrade cost, which would result in an economic carrying charge of \$31 million NPV for market purchases to replace Campbell Units 1 and 2 in 2023 and \$11 million NPV for market purchases to replace Campbell Unit 2 in 2023. 6 TR 498.

MEC witness Comings argued that the market capacity purchases could come from both the PRA and bilateral contracts. 8 TR 1882. But even if the capacity market purchases would not exceed the 5% PRA threshold, Mr. Comings assumed the ZRC cost of 56% of CONE is too low. 6 TR 526. Considering the retirement of Palisades, the proposed retirement of Karn Units 1 and 2, and DTE Electric Company's proposed coal unit retirement schedule, the price of ZRCs is likely to increase to at least 75% of CONE. 6 TR 526. Mr. Comings' use of a capacity price that is unreasonably low understates the purchase of ZRCs presented in his surrebuttal testimony by \$10 million for the retirement of Campbell Units 1 and 2 and by \$4 million for the retirement of Campbell Unit 2. 6 TR 526.

Mr. Comings' proposal that the Company rely on unspecified purchases of ZRCs also has the potential to result in a determination that the Company has a capacity need that must be filled with PURPA contracts. 6 TR 526. The costs for long-term PURPA contracts would be potentially higher than the single-year purchase of ZRCs proposed by Mr. Comings, and could be incurred by customers for a contract term length of up to 25 years. 6 TR 526. MEC did not reflect the cost impact of this considerable risk to customers, and as such did not fully consider the economics of using market purchases in support of the retirement of the Campbell units in

2023. 6 TR 527. The Company does not agree that it would be appropriate to rely on market purchases to replace Campbell Units 1 and 2, or Campbell Unit 2 alone, in 2023.

**e. Modeling Of Existing Unit Operation**

MCV witness Medine suggested that PCA costs are understated because the addition of renewable resource capacity does not result in an impact to the dispatch of the Campbell units or to MCV. 9 TR 2919-2920. Ms. Medine's argument is based on the incorrect assumption that the addition of new generation resources directly requires a decrease in production from other resources. 6 TR 500. Company witness Walz explained that as a participant in the energy market operated by MISO, the Company "operates its generating resources not only to serve customer demand, but also to optimize utilization of its resources to reduce power supply costs." 6 TR 500. With the addition of renewable resources, generation at the Company's existing owned nonrenewable resources is projected to remain stable. 6 TR 501. The added generation from renewable resources is expected to reduce reliance on energy market purchases, *not* reduce the economic dispatch of the coal units and MCV. 6 TR 501-502.

Ms. Medine also questioned the accuracy of the Medium 4 retirement analysis given Strategist's limitations in considering commitment of units having long lead times (such as coal units) and minimum run times based on startup and variable costs. 9 TR 2925. This limitation had no impact on the Medium 4 retirement analysis. 6 TR 503. Coal units in Strategist are assumed to operate as must-run resources, which means that they will run at least at minimum output levels in every hour a unit is available. 6 TR 503. This assumption in Strategist is consistent with how the Company offers the coal units into the MISO energy market, and thus the limitation in Strategist did not impact the modeling of the Medium 4 coal units. 6 TR 503.

## 5. Modeling of Commodity Price Forecasts

ABATE witness Pollock contended that the Company's projected wholesale market prices "are too optimistic, largely because the projections assume unrealistically high natural gas prices." 8 TR 2122. Mr. Pollock expressed concern that this results in projected energy costs savings under the PCA that are overstated. 8 TR 2129. To support his position, Mr. Pollock compared the AEO and Consumers Energy natural gas projections, which Consumers Energy used in its modeling in this IRP, with a market forward price for natural gas. 6 TR 503-504. Mr. Pollock's comparison is not valid. A market forward price is not a forecast; rather, a market forward price is a price published today for which a party can enter into a contract to supply a fixed amount of natural gas for any month in the future. 6 TR 504. The Company does not rely on forward prices as a long-term forecast, but instead considers the short-term trend of forward prices and relies on third-party industry experts to provide input on escalation rates into the future. 6 TR 504.

The natural gas prices used by the Company in this IRP were not "unrealistically high." AEO natural gas prices, which the Company was required to use pursuant to the MIRPP, were much higher than the Company's own natural gas prices. 6 TR 504. The Company used its natural gas price forecast to evaluate many scenarios and sensitivities. 6 TR 504. The Company acknowledges that it discovered a methodology discrepancy in its escalation of natural gas prices such that its natural gas prices should have been between 9% and 29% lower. 6 TR 504. Since the Company provided economic portfolio results for natural gas prices up to 25% below base case prices, natural gas prices in this lower range were considered in the Company's portfolio results. 6 TR 504.

Mr. Pollock suggested that a CC gas turbine could be more cost-effective than the Company's PCA where natural gas prices are lower. 8 TR 2129-2130. Consumers Energy agrees that a potential viable option includes adding natural gas-fueled resources, and included both a CC and a CT unit in its Alternate Plan. 6 TR 505. However, the PCA was developed based on the Company's review of a range of reasonable results, including varying natural gas prices. 6 TR 505. The PCA limits the risk to customers of uncertain natural gas prices compared to the addition of the natural gas-fueled generation units in the Alternate Plan. 6 TR 505.

## **6. New Technology Costs and Operating Characteristics**

### **a. Reliability And Capital Costs Of Solar Resources**

Attorney General witness Coppola asserted that under the PCA, the Company will in 2040 rely on solar resources to serve 63% of its PRMR. 8 TR 2365. Mr. Coppola increased the Company's presentation of 40% solar generation to 63% by reclassifying the EWR, CVR, and DR resources as reductions to peak demand and not generation resources. 8 TR 2365. While Mr. Coppola is correct that MISO treats EWR, some DR, and likely CVR as unregistered load modifying resources, many of the Company's DR programs are registered as capacity resources with MISO, and the Company expects that future DR expansion could also be registered as capacity resources. 6 TR 507. When only considering the known unregistered load modifying resources EWR and CVR, the amount of the PRMR being provided by solar in 2040 under the PCA would be 50% instead of the 63% suggested by Mr. Coppola. 6 TR 507.

Mr. Coppola also expressed concern that MISO requires the calculation of ZRCs for solar generation to be based on the summer months of June, July, and August during the hours of 3:00 p.m. to 5:00 p.m. 8 TR 2366. Ms. Walz noted that MISO awards ZRCs for *new* solar resources based on nameplate capacity multiplied by 50% as the class average, which is what the Company modeled. 6 TR 507, 609. The consideration of performance during specific hours of

summer months identified by Mr. Coppola applies to resources with at least a year's worth of performance. 6 TR 507. For those solar resources, the 50% class average is not used, but rather the production at time of peak relative to nameplate capacity is calculated. 6 TR 507.

Mr. Coppola argued that the Company's reliance on solar resources may result in the Company not having sufficient resources to meet demand in the middle of winter when the ideal summer circumstances do not exist. 8 TR 2366-2367. Company witness Walz explained that Mr. Coppola seemed to "confuse the requirement to serve peak demand with sufficient *capacity* resources, versus the economic delivery of *energy* to customers in every hour of the year." 6 TR 508. Mr. Coppola's argument is incorrect that the Company must provide 3,432 ZRCs of solar capacity in January. 6 TR 508. The Company is not required to provide a specified level of ZRCs, or *capacity*, except for the peak hour of the year. 6 TR 508. As for the hourly delivery of sufficient *energy*, the Company uses a combination of supply-side resources, demand-side resources, and the MISO energy market, which at times offers energy at a lower cost than the Company's resources. 6 TR 508. In response to discovery, the Company demonstrated that even in the extreme circumstance where no solar production is available, and the Company's energy market purchases are no greater than historical levels, the Company would still have sufficient resources under the PCA to meet peak demand in January 2039. See Exhibit AG-12.

Mr. Coppola also stated that the PCA's assumed reduction in solar generation capital costs "may not be realistic." 8 TR 2369. Mr. Coppola did not explain why he concluded that the assumed reduction in solar capital costs in the PCA "may not be realistic." 6 TR 509. Conversely, the Company indicated that responses to the Company's 2018 RFP support the assumed capital cost reductions in the PCA of 10% to 35% compared with BAU. The preliminary analysis of the solar proposals indicates an expected weighted average levelized PPA

cost of \$49.10/MWh for an up to 20-year contract and up to 100 MW in size. 6 TR 509. This cost represents a 50% reduction in the levelized costs of solar energy compared to those in the IRP's base case assumption. 6 TR 509. That said, even if the assumptions related to the reduction of solar capital costs do not hold throughout the planning period, the PCA provides the benefit of permitting the Company to pivot toward lower-cost resources. 6 TR 459.

**b. Single-Axis Tracking Versus Fixed-Tilt Solar Systems**

SEIA witness Lucas noted that the Company used only fixed-tilt systems in its modeling, and recommended that the Company procure single-axis tracking systems instead. 8 TR 1988. While the Company modeled fixed-tilt systems because of concerns with the operating costs and performance of solar tracking technologies, this IRP does not limit the Company to using fixed-tilt systems in the future. 6 TR 510. The Company is not seeking approval of any costs associated with solar capacity additions in this IRP. 6 TR 510. If single-axis tracking systems are able to provide better performance at a lower cost, then those systems are expected to be selected through the Company's proposed competitive bidding process. 6 TR 510.

**B. PCA**

**1. Approval Of PCA Generally**

MCV witness Medine and ELPC witness James P. Gignac both presented positions regarding the general approval of the Company's PCA. Ms. Medine suggests that a "long-term resource plan" cannot be approved in an IRP.<sup>21</sup> 9 TR 2905. Furthermore, Ms. Medine and Mr. Gignac both take issue with the fully integrated nature of the Company's PCA and the Company's reservation to abandon or amend its PCA if the Commission rejects or modifies any

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<sup>21</sup> At 9 TR 2920, Ms. Medine also states it is unclear what type of approval the Company is seeking for the Alternate Plan presented in its IRP filing. The Company's alternative plan was not intended to represent the recommended plan and no approvals are sought related to the Alternate Plan.

of the Company's proposals. 9 TR 2904-2905; 8 TR 2316-2322. These positions should be rejected.

Ms. Medine's position regarding the approval of a long-term resource plan is inconsistent with the law and the purpose of this proceeding. In this case, the Company was required to provide a 5-year, 10-year, and 15-year projection of the Company's load obligations and a plan to meet those obligations. See MCL 460.6t(3). Furthermore, in approving an IRP, the Commission is required to determine that the IRP represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. MCL 460.6t(8). Contrary to Ms. Medine's claim, these provisions provide for the filing and approval of a long-term resource plan.

Pursuant to the above statutory provisions, the Company is requesting that the Commission approve the Company's PCA, finding it to represent the most reasonable and prudent means of meeting the Company's energy and capacity needs. In requesting this approval, the Company is not seeking pre-approval of the costs in the entire PCA. The Company is only seeking pre-approval for costs associated with the EWR, DR, and CVR resources that the Company will incur in the three years subsequent to the Commission's approval of the IRP, as detailed above. The Company also acknowledges that its long-term resource plans will continue to be reviewed in future IRP proceedings.

Ms. Medine's and Mr. Gignac's criticisms of the integrated nature of the Company's PCA are also without merit. As conceded by both witnesses, MCL 460.6t(7) allows a utility to consider recommended changes to an IRP and file revisions before the Commission, if it chooses to do so. MCL 460.6t(9) also allows a utility to consider the Commission's rejection of an IRP and, at its option, submit revisions for Commission approval. In other words, a utility has the

ability to accept or reject modification to an IRP. The law does not require a utility to proceed with a modified IRP. Furthermore, MCL 460.6t(7) provides a utility with the option to voluntarily withdraw and refile IRPs. Therefore, the Company's reservation to abandon or amend its PCA if the Commission rejects or modifies any of the Company's proposals is consistent with the law.

With the above noted, the Company still intends to fully consider any Commission recommendations and, if appropriate, will make corresponding revisions. However, the Company continues to maintain the position that all of the Company's requests for relief must be approved since this is an integrated plan with proposals that support each other.

## **2. Timing Of Capacity Additions**

MCV witness Medine, Attorney General witness Coppola, and ABATE witness Pollock presented testimony concerning the timing of the capacity additions in the Company's PCA. Ms. Medine suggests that there is a disconnect between the ramp up of renewable resources and the ramp down of coal-fired and gas generation in the early 2030s which will impact the dispatch of MCV and the Campbell units in MISO. 9 TR 2919. Ms. Medine and Mr. Coppola also take the position that the Company should more closely align new capacity additions with capacity needs and reduce capacity surpluses. 9 TR 2918; 8 TR 2373. Mr. Pollock suggests that the Company's PCA is in shareholders' best interests, as opposed to customers' best interests, because the Company has allegedly "front-loaded" resources in the PCA. These criticisms should be rejected.

Contrary to Ms. Medine's claim, there is no disconnect in the PCA between the ramp up of renewable resources and ramp down of coal-fired and gas resources. Ms. Medine's criticism of the Company's PCA misunderstands how the MISO Energy Market actually functions and

unnecessarily raises a concern regarding the Company's modeling. Mr. Blumenstock explained that MISO's utilization of Campbell Units 1 and 2 and MCV are entirely dependent upon these units' cost of production versus their respective energy price. 6 TR 277. Furthermore, MISO's utilization of renewables has no impact on the cost of production for other generating units, nor will it have a significant impact on the energy price of Campbell Units 1 and 2 or MCV. 6 TR 277. Mr. Blumenstock further established the lack of correlation between renewable and fossil fuel generation by explaining that coal-fired and gas generation has not declined as renewable generation has been added to the mix of generation in MISO. 6 TR 277.

Ms. Medine's and Mr. Coppola's criticisms regarding new capacity additions being brought on too early and capacity surpluses should be rejected. It is unreasonable to assume that the Company can ramp up EWR, DR, and CVR, and build 5.1 GW of solar generation by 2031, in accordance with the Company's PCA, in a single-year. Building demand-side resource programs, which rely on customer participation, and 5.1 GW of solar generation takes time. 6 TR 277. Mr. Blumenstock explained that the PCA affords sufficient time for both MISO and the Company to gain experience with meeting energy and capacity requirements with the magnitude of the demand-side and solar generation proposed in the PCA and also lessens execution and delivery risk of developing significant amounts of capacity. 6 TR 277.

Mr. Blumenstock further explained that the capacity surplus created by the Company's PCA gives the Company flexibility to further evolve its resource portfolio by retiring existing generation units before they reach their end of lives. 7 TR 278. For instance, if the Company is able to achieve a surplus of capacity through its ramp up of demand-side and solar resources, the Company will analyze available options to reduce its capacity position, such as terminating the MCV PPA in 2025 or retiring other generating units before they reach their end of design life.

7 TR 278. Mr. Blumenstock explained that if the above analysis indicates that terminating MCV's PPA or retiring a Company-owned generating unit aligns with the planning objectives employed in future IRPs, the Company will take corresponding action. 7 TR 278.

Mr. Pollock's criticism regarding the front-end loading of fixed costs in the PCA, and attempt to tie this strategy to earnings opportunities, should be rejected. Mr. Clark presented testimony which made clear that the Company's modeling and development of the resources in the PCA only considered customer costs and did not consider earnings in any way. 7 TR 962. Mr. Clark further explained that, as the PCA took shape and it became clear that solar generation would be a significant part of the PCA, the Company identified a need to consider the implication of significant additions of PPAs. 7 TR 962. The tax treatment associated with ITC means that independent developers of solar resources have a significant cost advantage over utilities. 7 TR 963. Mr. Clark explained that, to address the risk to the Company associated with significant increases in PPAs, the Company's financial planning organization recommended that the FCM be pursued in accordance with the law. 7 TR 963.

### **3. Generation Resources**

#### **a. Solar**

##### **(i.) Capacity Value**

Attorney General witness Coppola and Staff witness Jesse J. Harlow both addressed the capacity value of the solar resources which the Company is proposing to utilize in the PCA. Mr. Coppola claims that there is a possibility of a reliability or capacity shortfall due to depending on solar resources during certain times and months of the year and also claims that solar resource capacity is based on actual capacity production multiplied by 50%. 8 TR 2366.

Mr. Harlow presented testimony which expressed concern that MISO may revise its capacity accreditation for solar generation. 9 TR 2713. These positions are addressed below.

Mr. Coppola's position regarding potential solar resource reliability and capacity issues is incorrect and unsupported in the record. The Company has established that the PCA satisfies the PRMR (i.e., MISO's resource adequacy construct) in every year of the IRP study period. 6 TR 278. Mr. Coppola has failed to provide any evidence to establish that this is not the case.

Furthermore, Mr. Coppola's criticisms of the capacity value of solar generation fails to consider that during non-peak months and hours when solar resources may not be providing maximum output, electric demand is typically much less than in peak periods. 6 TR 278. In the event that solar generation is less than electric demand in those periods, the Company has the ability to import energy from MISO. 6 TR 278-279. The Company has historically been a net importer of energy from MISO and has been able to import energy reliably. 6 TR 279. Even if reliability were to become a concern, which the Company submits is currently not the case, MISO would likely utilize Ludington as a storage asset to leverage energy gained during weekend and weeknight pumping periods and provide for adequate supply during periods in which renewable resources are not operating. 6 TR 279.

Mr. Coppola is also incorrect that solar capacity is based on actual capacity production multiplied by 50%. Mr. Blumenstock explained that Mr. Coppola has misinterpreted MISO's tariff for capacity accreditation of solar generation. 6 TR 279. The 50% factor, which is used to convert nameplate capacity to ZRCs for solar generation, is only applicable for newly installed solar generation that does not have any operating history. 6 TR 279. If operating history is available, MISO's tariff allows solar generation to base its ZRCs on the average production during the months of June through August, and the hours of 3:00 PM to 5:00 PM. 6 TR 279.

The Company's Grand Valley State University and Western Michigan University solar facilities, provide two examples of solar resources that were given a higher capacity credit than 50%. Mr. Blumenstock explained that after several years of operating history, these facilities were granted ZRCs based on 60% of their nameplate capacity for Planning Year 2018. 6 TR 279.

With respect to Mr. Harlow's solar resource accreditation concern, Mr. Blumenstock explained that changes in assumptions are always a risk. 6 TR 279. However, it should be noted that the Company's IRP assumed that solar generation will receive 50% capacity credit through 2039, based on MISO's current tariff provisions for accreditation of newly built solar generation without any operating history. Since the Company has relied on MISO's current tariff provisions in the development of its IRP, and no changes have been made by MISO regarding the accreditation of solar resources, there is no basis to modify the capacity credit assumptions utilized in the PCA.

Nevertheless, the Company is aware that MISO is considering a revision to its tariff on capacity accreditation for solar generation. In the event that MISO changes its tariff, and the Company receives a credit for its solar generation that is different from what was assumed in its IRP, which is not a certainty at this time, the Company will factor the different credit into its next IRP and adjust accordingly. 6 TR 280. The modular nature of the PCA affords the Company flexibility to alter capacity plans should a change in solar resource capacity credit occur.

**(ii.) Development**

The Attorney General expressed concern about the development of solar in the Company's PCA. Specifically, the Attorney General questioned the Company's ability to acquire sufficient land necessary for the planned solar development under the PCA. 8 TR 2368. This concern was based on the conclusion that a utility-scale solar project is 100 MW. 8 TR

2368. Mr. Coppola then contended that solar projects less than 100 MW reduce economies of scale, which result in higher power costs. 8 TR 2368. This is inaccurate.

There is no support for the position that a utility-scale solar project is 100 MW. Company witness Thomas defined utility-scale solar projects as 20 MW or larger. 8 TR 1389; see Exhibit AG-2. For purposes of the IRP, the Company considers this to be the minimum parcel size for utility scale solar, as reasonable economies of scale are available at this size. 8 TR 1384. However, other sources define utility-scale projects as being even smaller. In Exhibit MEC-2, the Lawrence Berkeley National Laboratory Report – Utility-Scale Solar -Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018, defines utility-scale solar projects as installations larger than 5 MW. Considering the size of the projects contemplated by the Company, there is adequate land available to accommodate utility-scale solar installations. Consumers Energy has found 8,200 parcels of land that met the Company’s ownership criteria at the conservative definition of utility-scale project sizes of 20 MW. 8 TR 1390. Those 8,200 parcels totaled 1,200,000 acres, which should provide ample siting opportunities that will deliver economies of scale. 8 TR 1390.

In addition to his concern about siting the projects, the Attorney General also indicated that the Company may not have fully considered local considerations and limitations regarding where these solar generating facilities are located. 8 TR 2368. While local consideration is very important when siting a solar project, many Michigan communities do not have zoning rules established for utility-scale solar, which imparts development risk to any solar development project. 8 TR 1391. However, solar is less locally intrusive and impactful than other energy projects. The modular nature of solar, the Company’s interest in geographical diversity in siting,

and the vast amount of land that could be developed for solar use are all important factors in mitigating this important development risk. 8 TR 1391.

Moreover, there is no support of the Attorney General's claim that solar projects less than 100 MW will reduce economies of scale and result in higher power cost. As discussed above, the definition of utility-scale and its inferred scale economies is not universally accepted. Exhibit MEC-2, the Lawrence Berkeley National Laboratory Report, establishes 5 MW as a threshold utility-scale size and demonstrates that installed prices for all utility-scale photovoltaics fall in a very small range. 8 TR 1390. Exhibit MEC-2 supports the conclusion that solar facilities above 5 MW do not offer significantly greater economies of scale. Since, the Company has proposed a selection process based on competitive bidding and power costs, regardless of project size, this will ensure that the projects are economic. 8 TR 1390. This will lead to more cost-competitive prices for customers. Thus, the Attorney General's concerns about the development of solar are unwarranted.

### **(iii.) Deployment**

SEIA witness Lucas recommended that the Company "advance the solar deployment schedule in its PCA" and bring online an additional 600 MW of solar in 2020 through 2023, for a total 2,400 MW of solar capacity by end of year 2023. 8 TR 1985-1986. The Company disagrees with Mr. Lucas's recommendation for several reasons. First, Mr. Lucas claimed that retiring Karn Units 1 and 2 in 2023 instead of 2021 will cost customers nearly \$80 million, and the Company could deploy more solar to replace Karn Units 1 and 2 in 2021. 8 TR 1974, 1986. The \$80 million of additional cost is incorrect because it: (i) suggests that all of the fixed costs to operate Karn Units 1 and 2 could be eliminated; (ii) does not acknowledge a cost of replacement energy for retiring these units in 2021 instead of 2023; and (iii) does not incorporate

the cost of Mr. Lucas's recommended solar capacity replacement. 6 TR 511-512. As discussed in Section IV.B.5 of this Initial Brief, other operational and feasibility concerns weigh against retiring Karn Units 1 and 2 in 2021. The Company presented a comprehensive analysis of retiring the Medium 4 units in 2021 and 2023, which concluded that retirement of Karn Units 1 and 2 in 2021 has the potential to save approximately \$17 million. 6 TR 512. This \$17 million in savings assumed the execution of the least-cost replacement that included a greater expansion of DR in 2021 (not solar). 6 TR 512.

Ms. Walz explained that the "gradual addition of solar capacity, as presented in the PCA provides the Company with the time necessary to gain experience in solar generation, including design, construction, procurement, and contract development." 6 TR 512. In addition, the PCA provides additional time for the Company to take advantage of technological advancements and reductions in costs for its solar capacity additions that are implemented throughout the 2020s. 6 TR 512. The Commission should reject SEIA's contention that the Company should rush into a much greater amount of solar in 2020 through 2023.

**b. DR**

**(i.) Response To Staff**

Staff witness David W. Isakson testified in support of Staff's proposed CPP addition to the Company's DR program, which Staff prefers over the Company's proposed UPR provision. 9 TR 2766-2772. As discussed below, the Company does not oppose the implementation of CPP in addition to the UPR provision, but not in place of the UPR provision. While Mr. Isakson raised issues in connection with UPR, none of them provide any basis to deny UPR.

The Company does not oppose Staff's CPP. As Mr. Ennis testified, the Company supports offering CPP as an enhanced feature of residential rates, similar to the UPR provision,

as a way to better reflect the cost of customers using capacity and energy at the time of system peak. 8 TR 1534. The Company views Dynamic Peak Pricing – such as CPP and UPR – as important resources for DR along with TOU rates and Direct Load Control DR resources. 8 TR 1534.

Consumers Energy views its UPR provision as the best approach for introducing and engaging customers in a “no regrets” way as part of a longer-term strategy to reduce peak demand by 1,250 MW by 2030. 8 TR 1535. Mr. Ennis cited three main reasons why UPR is the best approach for the Company’s customers and for Michigan: (i) customer research has shown the default selection feature of UPR to cost-effectively increase customer engagement from 18% to 95%; (ii) the overall cost-benefit advantages are greater when a default selection feature is used to introduce customers to rate options that influence customer behavior by reflecting the temporal difference in costs; and (iii) high customer engagement and satisfaction with rate options that include a default feature that customers can freely select or unselect.

Mr. Ennis testified to “several studies and reports indicating that customer engagement, retention, and satisfaction with a default rewards program is favorable.” 8 TR 1536. In November 2016, the U.S. Department of Energy’s Smart Grid Investment Grant Program published its final report on the impacts from 11 utility consumer behavior studies addressing key areas of behavioral DR design, including a default selection process to engage customers. The study was admitted as Exhibit A-117 (PCE-4). While per-customer peak demand reduction was generally lower for programs with the time varying rate features selected as a default, the aggregate demand reduction was much higher given the large number of customers participating. The default selection feature of the proposed UPR makes it more cost-effective because it avoids the customer acquisition costs to enroll participants. The same study found the benefit-cost ratio

was greater than 2.0 for programs with default features and between 0.7 and 2.0 for programs requiring customers actively select the feature, depending on rate and technology combination.

Mr. Ennis also testified that the Company's research made it aware of several studies and reports indicating that customer engagement, retention, and satisfaction with a default rewards program is favorable. 8 TR 1536. In Portland General Electric's flex pilot, customers selecting the Peak Time Rewards ("PTR") feature had the highest satisfaction ratings among 12 time-based pricing programs. Eighty-three percent of customers who selected the PTR feature were satisfied with the pilot and 73% of customers with the feature automatically selected were satisfied. Further, the above-referenced DOE report found that retention rates were similar between programs with and without the time-based pricing feature initially selected. Mr. Ennis testified that Consumers Energy is encouraged by these findings, as they suggest that the UPR will be an important tool to build customer awareness and engagement in understanding how capacity and energy costs vary based on the TOU, leading to greater customer acceptance of, and participation in, other existing and future time-based pricing programs. *Id.*

Mr. Isakson testified that Staff preferred CPP over UPR because UPR is susceptible to free-ridership and does not penalize customers who choose to not change their behavior during the event. 9 TR 2769-2770. The potential for free-ridership, however, is not sufficient reason for the Commission to not approve UPR. Mr. Ennis explained:

"While the Company does not dispute the potential existence of some free riders, the Company disagrees with the notion that it is a systemic issue that warrants disapproval of the Company's proposal. Free ridership is part of program costs and a small price to pay for a larger aggregate demand savings. Indeed, the purpose of calling an event is that customer demand on the system is too high. In other words, the problem is not that too many customers are using less air conditioning as they leave their house during an event day. However, it is anticipated that increased load during event days would generally offset the potential of free ridership. In

addition, Mr. Isakson suggests that the CPP provision he is proposing is not susceptible to free ridership. However, it seems equally as likely that some customers participating in the CPP will benefit from receiving the lower off-peak rates during the month and randomly avoiding the higher critical peak price during an event day just because they were not home.” 8 TR 1539-1540.

Thus, the possibility that a customer may occasionally receive a credit, without specifically intending to respond to a peak event, is not a basis to deny UPR. As Mr. Ennis pointed out, even Staff’s CPP is susceptible to free-ridership. In any event, if UPR results in the reduction of electric consumption during peak periods, even if coincidentally in some cases, then it will have met its goal.

Mr. Isakson also opined that the Company’s UPR is “opaque and imprecise.” 9 TR 2770.

The Commission should not accept this view. First, as Mr. Ennis explained, the UPR provision is not “opaque”:

“Q. On page 7 of his direct testimony [9 TR 2770], Mr. Isakson explains why he believes the UPR baseline is opaque. Does the Company agree with this conclusion?

“A. The Company recognizes Mr. Isakson’s point of view that customers should be made aware of the baseline, which they are being measured against. To that end, the Company is agreeable to including the customer baseline in the communication strategy for the UPR. However, the Company believes that for customers to have incentives to reduce usage during DR events it is not necessary for them to know their specific kW baseline. UPR customers need only to know that the effective cost of electricity is higher and they can save on their bills by reducing their consumption below normal or typical levels. As an example, customers generally do not know the consumption of a specific appliance in their home such as a dishwasher, washing machine, or air conditioner; however, they do understand that running these appliances outside of the peak hours will save them money during a peak event day. Further, the Company is confident that potential customer confusion could be overcome with thoughtful

research and experimentation with different ways to help customers understand the program.” 8 TR 1538.

Second, in response to Mr. Isakson’s claim that the UPR provision is “imprecise,” Mr. Ennis explained that: (i) the Company is working with Cadmus, a third-party evaluation company, to identify a customer baseline calculation method that is precise, transparent, replicable, and easy for customers and stakeholders to understand; and (ii) the Company would collaborate with Staff and other interested stakeholders to align on a robust method for establishing customer baselines. 8 TR 1536-1538. Thus, the Company would work to enable customers to understand that reducing consumption during peak events will save them money, and Consumers Energy has already begun working with Cadmus to refine the process to calculate such reductions and award credits to customers.

Mr. Ennis also addressed Mr. Isakson’s assertion (9 TR 2772) that the total peak demand reduction achieved through a CPP and the UPR would be substantially similar. With UPR, the aggregate demand reduction will be much higher given the large number of customers participating. Mr. Ennis noted that Mr. Isakson cited the Company’s Cadmus Report’s survey results for a CPP Program and a UPR-like program (“PTR” in the report) showing them to be similar in enrollment experience, satisfaction, and likelihood to recommend the program, and that the demand savings for each program type were similar. 9 TR 2772. As Mr. Ennis explained, however, the comparison in referenced report was not significant as, unlike UPR, both programs were opt in, rather than default. 8 TR 1538-1539.

As a result of the foregoing, the Company does not oppose the implementation of CPP in addition to UPR, but Mr. Isakson provided no basis for disapproval of UPR. The UPR provision, therefore, should remain in the PCA.

(ii.) **Response To SEIA**

SEIA witness Lucas expressed his opinion that the PCA's DR portfolio "should not be viewed as a trivial effort . . . ." 8 TR 1964. In a similar vein, Staff witness Smith stated that "Staff is somewhat concerned that the 1,250 MW reduction by 2030 is ambitious and would like to evaluate the ramp-up timeframe from 2022-2030 in the next IRP filing." 9 TR 2756. For the reasons provided below, neither SEIA's witness nor Staff's witness provided a basis to conclude that the Company cannot achieve the targeted 1,250 MW reduction through DR as reflected in the PCA.

As Mr. Ennis testified, the vast majority of the Company's DR would simply ramp up its proven customer demand-side programs. First, Mr. Ennis noted that the Company's Peak Power Savers (Residential A/C Cycling) Program is reliant on smart meter technology. 8 TR 1541. The Company only recently completed the required implementation of smart meters and smart meter IT. As a result, the Company could not begin recruitment into the program in earnest until late 2016, and therefore, the capacity additions between 2016 and 2018 provide a better representation of the Company's ability to add capacity in this program than the historical period 2013 through 2016. The Company's TOU programs and planned additions also relied on smart meters and smart meter IT, therefore, the same holds true for those as well. *Id.* Additionally, the Company did not even include the projected MW reductions for its BYOT pilot into its PCA. 8 TR 1526.

Second, as Mr. Ennis testified, the Company has seen additions in its Interruptible Rate GI in recent years as a direct result of changes to the tariff implemented with the Company's electric rate case, Case No. U-17990, which allowed the maximum level of participation to

increase. 8 TR 1541. The Company expects the increased amount of capacity being provided today from this program to persist. *Id.*

Third, prior to 2016, the Company had not registered its Energy Intensive Primary Program with MISO, and therefore did not include the program in its demand-side capacity resources numbers. 8 TR 1541. Once MISO accepted the program as qualifying as a Load Modifying Resource in 2016 the Company began including it in its demand-side program resources. *Id.*

Fourth, increases in C&I DR between 2019 and 2023 rely primarily on the expansion of the Company's recently implemented C&I DR Program. 8 TR 1541. The program was piloted in 2015, implemented as a full program in 2017, and ramped to deliver 74 MW of DR for the 2018 through 2019 Planning Year. The short-term additions to this program assume a similar ramp up through 2022. The Company's success with this program over the last two years make the increases seen from 2017 to 2018 more representative of the future success of the program than 2013 to 2017. *Id.*

As discussed above, Mr. Fratto testified that the amount of DR included in the PCA was reasonable. Mr. Ennis had also identified execution risks for DR, and described the actions being taken to minimize or mitigate these execution risks, which included the Company studying options to utilize new and/or existing platforms to capture the data from smaller business customers. 8 TR 1526-1528. No party witness rebutted or in any way challenged Mr. Fratto's analysis.

The Company looks forward to working with Staff and others to evaluate the ramp-up timeframe in the next IRP. As Mr. Ennis testified, "[w]hile the DR goals are not 'trivial,' the Company believes it can successfully achieve the DR goals presented in this case with

Commission and stakeholder support of new residential and business DR initiatives.” 8 TR 1542. As no party’s witness showed that the Company could not achieve the PCA’s 1,250 MW reduction, the PCA should continue to assume that the Company will achieve its goal.

**(iii.) Response To ABATE**

ABATE witness Pollock asserted that “if DR supplies Consumers’ entire reserve margin (and more), DR customers may experience curtailments of both greater frequency and duration. Thus, the PCA will place DR customers at much greater risk. At the very least, they will require additional compensation to offset greater risk.” 8 TR 2127. The Commission should reject this assertion as it is based on an incorrect assumption and is without merit.

Mr. Pollok’s position assumes that the purpose of the Company’s DR programs is to provide the Company’s entire reserve margin. The assumption is incorrect. As Mr. Ennis testified, the Company is not proposing DR to provide its entire reserve margin. 8 TR 1543. The PCA is a holistic approach that uses both supply-side resources and demand-side programs to achieve a portfolio of assets to provide for both of its capacity and reserve requirements. *Id.* Further, as Company witness Ms. Walz testified, not only did Mr. Pollok misunderstand the difference between the PRMR and the RMR, his testimony reflected a misapplication of how reserves are delivered to MISO. See Section IV.A.4. of this Initial Brief.

Further, as Mr. Ennis testified, the Company has included increased compensation for customers participating in the C&I DR Program. 8 TR 1543. As the DR capacity increases, compensation for C&I DR customers is increased incrementally every other year. This incremental increase in customer compensation is primarily to address the supply of customers willing to participate in a C&I DR Program, and contrary to Mr. Pollok’s claim, is not due to the increased risk the customer will be called upon to curtail in the event of a MISO declared event.

Additionally, current DR programs are limited to a certain number of interruptions per year and are limited in duration to four hours per event. *Id.* Based on these programs and the continuation of their limits, participating customers will not experience greater frequency and duration of interruptions.

As a result of the foregoing, Mr. Pollok's assertions are based on incorrect assumptions, are without merit, and the Commission should reject them.

**c. CVR**

**(i.) Staff's Proposed Recovery Alternatives**

Staff witness Tayler Becker addressed four different scenarios in which the Company's CVR costs might be granted:

“Scenario 1: The Commission Order in Case No. U-20134 authorizes approval of the Company's entire 2019 projected test year spend for CVR. . . .

“Scenario 2: The Commission Order in Case No. U-20134 authorizes approval of a portion of the Company's 2019 projected test year spend for CVR, but disallows the rest as untested. . . .

“Scenario 3: The Commission Order in Case No. U-20134 does not authorize approval of the Company's 2019 projected test year spend for CVR due to the program being deemed an unnecessary or imprudent investment. . . .

“Scenario 4: The Commission Order in Case No. U-20134 does not authorize approval of the Company's 2019 projected test year spend for CVR due to the program being deemed a better fit for the IRP case. . . .” 9 TR 2782-2784.

Mr. Ortiz testified in response to Mr. Becker's four scenarios. 8 TR 1639. Mr. Ortiz explained that the Company's preference is that the total 2019 test year projected CVR capital costs be approved in Case No. U-20134 (\$39,100,000), and the IRP capital costs (\$8,924,600) be approved in this IRP proceeding. Alternately, if the Commission were to find that the 2019 test year capital costs in Case No. U-20134 are better suited for approval in this IRP as a complete

CVR capital cost approval (\$48,024,600), the Company would not disagree with this method. *Id.*

Staff witness Becker expressed concern over whether the Company will have the ability to stay within voltage range and avoid “infrequent fluctuations.” 9 TR 2781. Mr. Ortiz responded to the concern, explaining that, throughout the CVR pilot testing the Company will monitor every recorded customer voltage point for every hour of CVR operation, and if frequent fluctuation voltage violations occur, the Company will take corrective action to resolve the issue. 8 TR 1637. Mr. Ortiz also specifically noted that the Company intentionally selected CVR pilot circuits with voltage levels above the minimum voltage threshold. *Id.*

Mr. Becker also stated that he had a concern over whether the Company’s planned technology components would communicate on the same platform. 9 TR 2781. Mr. Ortiz responded to the concern, and verified that the technology components will be able to communicate with each other, stating:

“In Consumers Energy’s Electric Distribution Infrastructure Investment Plan, Exhibit A-118 (MAO-5), page 52, the Company references the Field Area Network (‘FAN’) architecture and highlights that there are currently over 4,000 line and substation automation devices communicating using this standard-based FAN architecture for increased interoperability. Exhibit A-118 (MAO-5), page 59, also references the use of industry interface standards for Distribution Management. The Company’s approach of leveraging industry standards will promote interoperability between substation and line grid devices and operation grid applications, reducing the implementation risk of these technology components not working as a comprehensive solution.” 8 TR 1638.

Staff witness Becker also recommended that the Company work with Staff to ensure CVR reporting is completed as outlined in his Exhibit S-14.1 (TJB-2). 9 TR 2784. Mr. Ortiz testified that the Company agrees that CVR reporting should be completed and reviewed with

Staff. However, as the Company will maintain an internal model of CVR, which will include all projected spend and capacity levels, as well as all other requirements that Staff has included in Exhibit S-14.1 (TJB-2). Thus, the Company requests that, if the Commission requires such reporting, it permit the report to be formatted differently from Exhibit S-14.1 (TJB-2), as long as it includes all of the data in that exhibit, which will prevent the Company from duplicating work.

**(ii.) Regulatory Accounting Treatment**

Staff witness Jay S. Gerken presented Staff's position and William A. Peloquin presented GLREA's and RCG's position regarding accounting treatment for recovery of remaining unrecovered net book value of Karn Units 1 and 2. In his testimony, Mr. Gerken testified that Staff recommends the Commission "deny the Company's request for Regulatory Asset treatment for the net unrecovered book value of Karn Units 1 and 2." 9 TR 2825. Calling regulatory asset treatment "unnecessary," Mr. Gerken argued that "traditional ratemaking already provides an avenue for recovery of the unrecovered net book value and the decommissioning costs anticipated to be incurred." 9 TR 2825. Similarly, Mr. Peloquin argues "no real need" to establish a regulatory asset, saying that "under traditional utility accounting, the utility continues to receive its return of and return on its investment." 8 TR 2475-2476; 8 TR 2487-2488. However, as Ms. Myers discussed in her direct and rebuttal testimony, regulatory asset 2031 treatment is "essential" to the Company's PCA, has lower revenue requirements, lower NPV, and reduced rates over that of traditional retirement accounting. 7 TR 1043, 1048.

While Mr. Gerken acknowledges that regulatory asset treatment provides a more favorable NPV, and only states that costs for Karn Units 1 and 2 are currently being recovered through traditional ratemaking, neither he nor Mr. Peloquin present any evidence of the benefits of traditional ratemaking over the proposed regulatory asset treatment and, further, they do not

address Ms. Myers' analysis of reduced revenue requirements and reduced rates. See 9 TR 2827. Furthermore, while Mr. Gerken downplays the demonstrated benefits of regulatory asset treatment as having no "significant" impact, the record evidence demonstrates that regulatory asset treatment does, in fact, have a beneficial impact, and Staff provides no rationale for its recommendation to forego the advantages and benefits so demonstrated. The Company submits that any benefit to ratepayers should be considered and, thus, the proposed regulatory asset treatment, which is an integral and "essential" part of the Company's IRP, should be approved by the Commission.

**d. EWR**

Staff witness Brad B. Banks testified that Staff found that the Company's EWR savings goals in the PCA are reasonable and that the Company will be able to reach its savings targets. 9 TR 2745. Staff stated that because of the Company's strong network of trade allies, Staff "sees an opportunity for the Company to take the lead on standardizing the certification of its weatherization contractors to align with the higher standards required by the Michigan Department of Health and Human Services." 9 TR 2746. Consumers Energy agrees that the Company should consider such standardization, and that the issue should be addressed in greater detail in the Company's next EWR Plan proceeding in 2019. 8 TR 1589. The Company is open to discussing this opportunity with Staff and other interested parties prior to the 2019 EWR Plan filing. 8 TR 1589.

Staff witness Banks also stated that once the Company has met its annual EWR savings goals, Staff would like to see the Company invest in health and safety deferral issues with Community Action Agency partners, particularly in low-income housing. 9 TR 2746. While the Company agrees that it should continue to consider ways to address health and safety deferral

issues, this consideration should also be addressed in additional detail in the 2019 EWR Plan proceeding. 8 TR 1589. Consumers Energy intends to continue working with Community Action Agencies and other stakeholders in the Low-Income EWR Collaborative to explore programs to address this issue. 8 TR 1590.

ABATE witness Pollock asserted that the per unit incremental cost associated with the increase in EWR from 1.5% to 2.0% from 2021 through 2033 ranges from \$0.44 to \$0.70 per kWh, and that EWR “is not an inexpensive energy resource.” 8 TR 2126. Company witness Ykimoff identified two errors in Mr. Pollock’s calculation. First, Mr. Pollock did not account for the measure life of energy savings, which resulted in overstating the lifetime per unit costs of EWR as a resource. 8 TR 1590. The associated energy savings for EWR programs often persist for multiple years, and thus it is common industry practice to incorporate the measure lives when determining the per-unit cost of conserved energy. 8 TR 1590. When properly considering the measure lives, the incremental cost of EWR is reduced to between \$0.038 and \$0.061 per kWh. 8 TR 1590. Second, Mr. Pollock included the entire financial incentive in his calculation instead of just the incremental amount associated with exceeding 1.5% energy savings. 8 TR 1590. After making this correction, the average incremental per-unit cost projected for EWR is \$0.035 per kWh between 2020 and 2040. 8 TR 1590. Accordingly, Mr. Pollock’s implication that EWR is an expensive resource is incorrect.

**e. Wind**

The Company properly considered the development of wind in its PCA. The Company has 525 MW of wind capacity additions planned by year 2021 as part of the Company’s RE Plan and an additional 25 MW planned beyond the RE Plan. 6 TR 493. No additional wind capacity

was selected for inclusion in the Company's PCA. ELPC and MEC disagreed with the treatment of wind in the IRP. 8 TR 2280; 8 TR 1835.

In addition to discussion in Section IV.A.4.c of this brief regarding the modeling of wind resources, there are potential limitations in developing wind in Michigan. While ELPC witness Daniel discusses the technical potential for wind in Michigan (see 8 TR 2282), the potential portrayed for further wind development in Michigan is inaccurate. While Mr. Daniel argues that there is 81 GW of technical potential, this would consume 20% of all non-urban land in Michigan, after also accounting for the land covered by roadways. 8 TR 1392. It is not remotely possible to develop this much wind in the state. While there are no statewide bans on wind development (8 TR 2282), wind developers must comply with the requirements established by local zoning authorities. Wind development in Michigan has been concentrated in the Thumb region of the state because this is where the state's best wind resources are located. 8 TR 1393. This area of the state has enacted moratoriums or restrictive zoning ordinances to address local concerns and limit future wind development. This has caused wind developers to move into other areas of the state. These projects reflect reduced wind resources. This is because power prices increase as development moves to less attractive wind resources. This reduces the technical potential for wind development in the state by economic means. 8 TR 1393.

Moreover, the PTCs will not have the same impact on these wind projects. This is because wind power prices are affected by the phase out of the PTCs. 8 TR 1393. In order for a wind project to obtain the full credit, the project needs to meet the Internal Revenue Service construction criteria and go into production by the end of 2020, but the credit reduces by 20% each subsequent year. 8 TR 1393. As developers are trying to qualify for the full tax credit, 2019 and 2020 are significant construction years. This causes materials and construction

resources to be in short supply and has the effect of placing an operational cap on wind development in the state. 8 TR 1394. Future year projects will not be as attractive, so this limits the technical potential for wind development in the state by economic means. Therefore, the Company properly considered the development of wind resources as part of its PCA.

**f. MCV**

As an assumption in the IRP, Consumers Energy modeled an extension of the MCV PPA. MCV witness Medine argues that the assumption of extending the MCV PPA through 2030 is a “constructive extension” of the PPA, and that the Commission should acknowledge this planning assumption as a “constructive extension.” 9 TR 2905. However, the Company’s planning assumption is not a determination of its contractual rights. 6 TR 273. The Company has an option to unilaterally extend the contract by providing notice between December 1, 2023 and March 15, 2024. 8 TR 1280. The Company has neither forfeited its option to purchase the MCV plant as provided for in the MCV PPA nor allowed the PPA to terminate in 2025. The Company’s PCA allows for flexibility in the future which could result in changes to the current plan, including the solar “glide path.” 8 TR 1280. A decision concerning an extension of the MCV PPA will be made before 2025 and supported in a future IRP filing.

MCV claims that absent a decision on the extension of the MCV PPA, the Company would need to provide for capacity to replace MCV by 2025. 9 TR 2916. This is not an accurate portrayal of the Company’s capacity position. Absent the MCV extension, the Company only experiences a shortfall in 2025 and 2026. 6 TR 275. Replacing this capacity can be accomplished through several means - a short-term capacity purchase, expediting elements of the Company’s PCA, or some combination thereof. 6 TR 275. Replacing a potential two-year shortfall with a five-year extension is not necessary.

Additionally, MCV witness Medine criticizes the surplus capacity for the Company's PCA over the period of 2025 to 2030 and argues that extending the MCV PPA to 2035 will address the surplus capacity. 9 TR 2917. However, the Company's current PPA with MCV has no provision for extension beyond 2030. 6 TR 275. This is why MCV is not considered a resource option after 2030 – for purposes of the IRP.

#### **4. Cost Approvals Generally**

At 9 TR 2543, Staff witness Paul Proudfoot recommended that the DR and CVR capital costs that the Company expects to incur in the three years following Commission approval of the IRP should be pre-approved. However, Mr. Proudfoot also took the position that, while reasonable, the EWR, DR, and CVR O&M costs that the Company has also sought pre-approval of in this case should be reviewed in subsequent cases. While the Company agrees with Staff's position regarding the pre-approval of DR and CVR capital costs, the Company does not agree with Staff's proposed treatment of EWR, DR, and CVR O&M costs.

The Company maintains the position that all requested costs for EWR, DR, and CVR -capital and O&M—are integrally related, and should not be severed. Pre-approval of the entirety of the costs, not just the capital costs as Staff has proposed, allows the Company to proceed with the implementation of these resources with confidence. 6 TR 263. The Company therefore requests the Commission to: (i) find that the EWR, DR, and CVR O&M costs that the Company expects to incur in the three years following approval of this IRP are reasonable and prudent and (ii) provide assurance of the future cost recovery of these O&M costs, provided the Company follows the plan approved in the IRP. Additionally, the Company requests the Commission to specifically find that the identified EWR, DR, and CVR resources, and the

corresponding capacity value of these resources, are approved as part of the Company's IRP and PCA as the most reasonable and prudent means of meeting the Company's capacity needs.

## **5. Medium 4 Retirement Analysis**

### **a. Retirement Recommendations**

The parties have presented a broad spectrum of positions related to the Company's Medium 4 Retirement Analysis and proposal to retire Karn Units 1 and 2 in 2023. Staff supports the Company's proposal to retire Karn Units 1 and 2 in 2023. 9 TR 2684-2685. ELPC/MEC witness Jester also found "the Company's IRP to be generally persuasive as to an early 2020s retirement date for Karn 1 and 2." 8 TR 1778. However, ABATE (at 8 TR 2133) and MCV (at 9 TR 2906) support the continued operation of the Medium 4 units until 2031. Furthermore, MEC claimed that the early retirement of all Medium 4 units is in the customers' best interest and SEIA took the position that an earlier retirement of Karn Units 1 and 2 should be pursued. See 8 TR 1863; see also 8 TR 1974. Finally, the Attorney General indicated support for not retiring Campbell Units 1 and 2 prior to 2031 and is "neutral on whether Karn Units 1 and 2 should retire early." 8 TR 2047.

Although the Company remains committed to the recommendation to retire Karn Units 1 and 2 in 2023, provided that the other aspects of the Company's PCA are approved, the wide range of positions presented by the parties in this case reinforces the Company's conclusion that the results of the Medium 4 Retirement Analysis are unpersuasive, as neither retirement nor continued operation were clearly favored.<sup>22</sup> The following responds to the positions of MEC, SEIA, MCV, and ABATE.

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<sup>22</sup> Staff agreed that "neither retirement or continued operation" of the Medium 4 units "is strongly favored." 9 TR 2685.

**(i.) Response To MEC**

MEC witnesses Evans and Comings addressed the Company's Medium 4 Retirement Analysis and presented counter retirement proposals. Specifically, MEC proposes that the Company's PCA be modified to plan for the retirement of Campbell Units 1 and 2 in 2023, in addition to the Company's proposed retirement of Karn Units 1 and 2. 8 TR 1863. In the alternative, MEC proposes that the Company's PCA be modified to include the retirement of Campbell Unit 2 and Karn Units 1 and 2 in 2023. Finally, MEC proposes that if the Company does not modify the PCA at the Commission's direction or on its own initiative "the Commission ask the Company to conduct a more thorough analysis of the retirement of Campbell Units 1 and 2." 8 TR 1863.

MEC points to six issues which it claims support its alternative retirement proposals. These issues include: (i) coal price issue discovered in the Company's analysis; (ii) the Company's assumed base capacity price; (iii) the retirement scenarios considered in the Company's analysis; (iv) the Company's capital spend plan and its influence on the retirement date; (v) differences between historical capacity factor and projected capacity factor of the Campbell units; and (vi) the impact of MEC's alternative modeling. 8 TR 1836-1850, 1857-1863. The Company comprehensively addressed MEC's arguments in the record and established that each of the issues identified above fails to support the early retirement of Campbell Units 1 and 2 in 2023. For the reasons discussed below, the Commission should reject MEC's recommendations which would result in Campbell Units 1 and 2 being retired prior to 2031.

**(a.) Coal Prices**

The coal price error identified in the Company's IRP modeling does not support the early retirement of Campbell Units 1 and 2. Mr. Clark explained that, subsequent to the filing of the

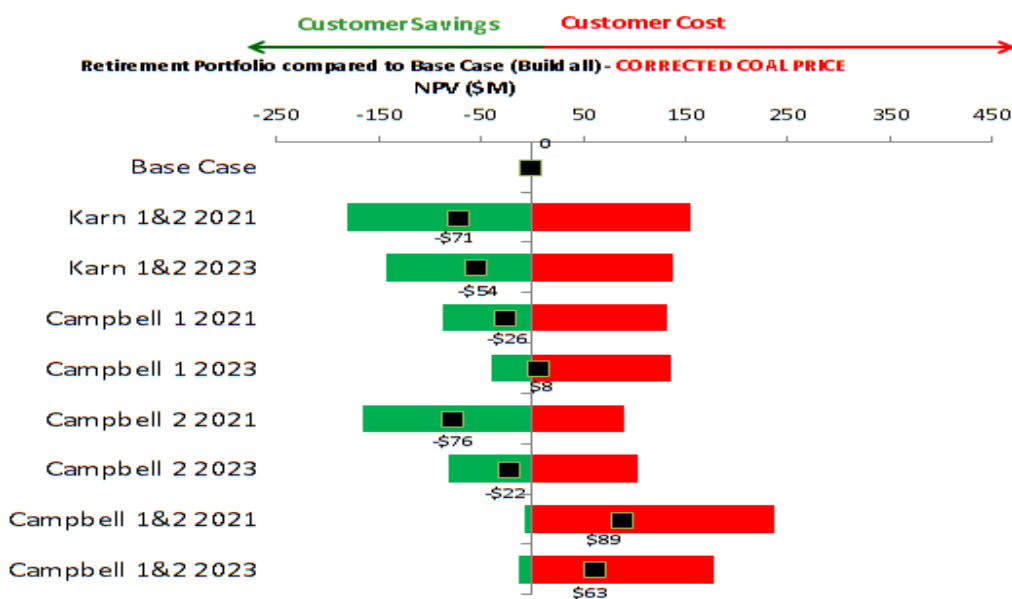
Company's IRP, the Company reviewed modeling inputs during the discovery process and identified an inadvertent Strategist software error which kept coal prices flat, at 2022 nominal values, in years 2023 and beyond. 7 TR 946. When the Company corrected this coal price issue through additional modeling, the Company determined that revised coal prices did not materially change the PCA or the Company's Medium 4 Retirement Analysis.

Mr. Clark explained that correcting the coal price error resulted in three impacts to the Company's IRP modeling in support of its PCA. First, the Company observed a lower economic dispatch of the Company's owned coal units and an increase in overall utility costs. Second, the Company determined that utility NPV costs increased by approximately 1% of total NPV utility costs. Finally, of the 147 scenarios and sensitivities presented by the Company, the Company determined that in 92% of the economically selected resource expansion plans were unchanged. 7 TR 946-947. Since greater than 90% of the economically selected resource expansion plans were unchanged as a result of the model re-runs with the corrected coal prices, the Company determined the revised coal prices to have no impact on the PCA.

With respect to the impact on the Medium 4 Retirement Analysis, Mr. Clark explained that the corrected coal prices improved outcomes for early retirement of coal-fired generating units. 7 TR 947-949. The Company determined an additional \$40 million NPV of savings attributable to early retirement of Karn Units 1 and 2 or Campbell Units 1 and 2. However, this does not mean that the corrected coal prices support retiring either or both of Campbell Units 1 and 2 in 2023 in addition to Karn Units 1 and 2. Mr. Clark explained that a review of the economic outcome of early retirement of Campbell Unit 1, Campbell Unit 2, or Campbell Units 1 and 2 together under the revised coal price analysis indicates that the retirement results for

these units did not change materially from what the Company initially presented in this case. 7 TR 948.

As demonstrated in the figure below which considers the corrected coal prices in the Medium 4 Retirement Analysis, the retirement of one Campbell unit is slightly positive but the retirement of both units in 2023 would increase customer costs by \$63 million NPV. 7 TR 948. Therefore, the Company’s proposal to continue the operation of Campbell Units 1 and 2 until 2031, which is the end of the design life of these units, remains the best choice for customers.



**(b.) Capacity Value**

MEC’s next argument suggests that a capacity value of 50% CONE would be more reasonable to use in the Medium 4 Retirement Analysis than the Company’s 75% CONE assumption. MEC asserts that a lower CONE amount was allegedly supported by Company witness Haugh, that the Company has used a lower CONE amount in past studies, and that a lower capacity value supported in a recent reverse capacity auction conducted by the Company and recent MISO PRA results. 8 TR 1838-1840. These arguments should be rejected as they are without merit.

Mr. Clark explained that Pace Global's projection of capacity prices is fundamentally different from the Company's projection and does not discredit the Company's CONE assumption. The Company relies on the MISO calculated CONE, which represents the most the Company would pay for capacity under current capacity market constructs, and Pace Global relies on an estimate of CONE which is developed in-house. 7 TR 949-950. In developing their CONE value, Pace Global relies on significantly different assumptions related to asset life and reflected new corporate tax rates, which became effective after the IRP assumptions were input into the model. 7 TR 950. Additionally, Mr. Clark explained that Pace Global's projection relied on an independent forecast of MISO's reserve margin and MISO's overall reserve margin may be different when considering zone specific resources. 7 TR 950. Finally, while Pace Global uses a different methodology to project CONE, it should be noted that Ms. Haugh supported the Company's assumption of 75% of CONE as a reasonable capacity price projection.

Mr. Clark further explained that, while the Company has utilized different CONE values in the past, such as in the analysis in Case No. U-18322, the Company had confidence at the time of those analyses that sufficient lower cost resources could be utilized to meet the need created by retiring two of the Medium 4 units. 7 TR 950. The confidence that sufficient lower cost resources could be utilized came from the Company's recent work on the Palisades PPA Buyout Replacement Plan. 7 TR 950-951. However, Mr. Clark explained that the Company's modeling in this case made clear that retirement of additional capacity resources would require the addition of less cost-effective new resources. 7 TR 951. As illustrated in the Corrected Coal Price Retirement Analysis figure above, the retirement of Campbell Units 1 and 2 in 2023 would cost customers \$117 million more than the retirement of Karn Units 1 and 2 in 2023. Mr. Clark explained that this increase in cost is primarily caused by the larger amount of capacity that must

be replaced with the retirement of Campbell Units 1 and 2.<sup>23</sup> 7 TR 951.

MEC's attempts to use the Company's recently completed reverse capacity auction and the MISO PRA to support a 50% capacity value assumption are also in error. Mr. Clark explained that the results of reverse capacity auctions should not be relied upon as representative of long-term capacity replacement costs because they represent "only a snapshot in time" and occurred in a period where continued operation of the Palisades and Karn Units 1 and 2 existed. 7 TR 951. The price at which these counterparties are willing to sell capacity to the Company is expected to change with market conditions. Moreover, the MISO PRA does not represent reliable capacity values to replace the Medium 4 because it represents a residual market and not a permanent supply that can be relied on to meet customer demands. 7 TR 952.

(c.) **Retirement Scenarios Considered**

Contrary to MEC's claim that the Company should have considered other retirement outcomes, the Company presented results for various retirement scenarios for the Medium 4 units, but those results are not additive. Mr. Clark explained that the savings associated with Karn Units 1 and 2 retiring (\$54 million) cannot be added to the costs of Campbell Units 1 and 2 retiring (\$63 million) to establish that retiring all of the Medium 4 units would result in customer cost increases of \$9 million. 7 TR 952. This is because the results of the Company analysis are dependent on the specific capacity replacement options leveraged to replace the retiring capacity. 7 TR 952.

Mr. Clark further explained that the results from the Company's Medium 4 Retirement Analysis suggest that the higher cost to customers associated with the retirement of Campbell Units 1 and 2 is at least partially driven by the need to replace the larger amount of capacity that

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<sup>23</sup> Campbell Units 1 and 2 represent 620 MW of capacity while Karn Units 1 and 2 represent only 515 MW of capacity. 7 TR 951.

is provided by these units. 7 TR 952. The Company's Medium 4 Retirement Analysis shows that the additional 105 MW of capacity provided by Campbell Units 1 and 2 costs customers about \$117 million NPV. 7 TR 952-953. The unfavorable economics associated with the retirement of Campbell Units 1 and 2 would therefore only worsen if all Medium 4 units were retired at once. 7 TR 952. Mr. Clark further explained that if Karn Units 1 and 2 were retired in addition to Campbell Units 1 and 2 in 2023, it would have the effect of retiring an additional 515 MW and would therefore drive up reliance on higher cost capacity resources and result in significant costs to customers. 7 TR 953.

**(d.) Capital Spend Plan**

MEC witness Comings testified regarding his belief that the Company was "front-loading" capital costs for Campbell Units 1 and 2 in the 2023 retirement scenario in order to make a 2023 retirement appear more expensive. 8 TR 1847. In support of this contention, he relied on a table showing the variation in projected non-environmental capital spending at Campbell Units 1 and 2 between the Company's electric rate case in Case No. U-18322 and this IRP proceeding for the 2023 retirement scenario (8 TR 1846), and a table showing the same variation between Case No. U-18322 and the IRP's 2031 retirement scenario (8 TR 1847). Mr. Comings' claim is without merit. As Company witness Kapala testified, spending variations were attributable to periodic updates in cost projections. Mr. Kapala explained that the Company periodically reviews and modifies the capital expenditures in its investment and operating plans, and during the intervening period between rate cases, the Company changes its investment and operating plans based on its periodic reviews of investment and operating plans. 8 TR 1166.

Mr. Comings also presented a chart illustrating year-by-year differences in non-environmental capital spending at Campbell Units 1 and 2 between the 2031 and 2023

retirement scenarios for those two units, as presented in this case, and then criticized the Company's plan to spend more at Campbell Units 1 and 2 in 2018 and 2019 under a 2023 retirement scenario, as compared to a 2031 retirement scenario. 8 TR 1845. Again, the criticism is baseless. Mr. Kapala testified that, if the retirement of Campbell Units 1 and 2 were advanced from 2031 to 2023, the Company would in fact pull forward some capital expenditures, but other expenditures would be reduced or eliminated. However, the purpose would be to ensure the reliability of units until their retirement date, not to manipulate the IRP analysis, as Mr. Comings claimed. 8 TR 1167.

Mr. Kapala went on to point out that, as shown in his Exhibit A-42 (NJK-2), during the time frame from 2018 through 2023, in a 2031 retirement scenario, the Company would invest \$120,996,000 in capital projects at Campbell Units 1 and 2. 8 TR 1167. In a 2023 retirement scenario, during the time frame from 2018 through 2023, the Company would invest \$84,186,000 in capital projects at Campbell Units 1 and 2. As a result, even when some capital expenditures were pulled forward under a 2023 retirement scenario, the 2023 retirement scenario still provided a net \$36,810,000 reduction in capital spending at Campbell Units 1 and 2. Mr. Kapala emphasized that although these projects increase spending in 2018 and 2019, the projects are not incremental to the Company's overall multi-year plan, but are simply being pulled forward from one-year to another to ensure reliability. *Id.* He went on to explain why, even though the 2023 retirement scenario would involve \$36,186,000 in less capital spending at Campbell Units 1 and 2 over the period from 2018 through 2023, versus a 2031 retirement scenario, the Company projected higher capital spending in 2018 and 2019 under the 2023 retirement scenario:

“This is because in a 2023 retirement scenario, incremental expenditures, necessary to keep the unit operating reliably and

safely through its retirement in 2023, and which were originally scheduled for later dates, might be moved ahead in order to ensure that key components have sufficient lifespan to last until 2023. The projects that would be pulled forward to 2018 and 2019, to ensure that safety and reliability are maintained in a 2023 retirement scenario, are reflected in my workpaper ‘WP-2 Campbell 1 & 2 Capital.’ At Campbell Unit 1, the projects that would be moved forward, increasing capital spending in the 2018 through 2019 time frame, include:

\* \* \*

“The purpose of pulling these projects forward under a 2023 retirement scenario is to ensure that the projects remain aligned with planned outages even as plant lifespan schedules change. In the event that Campbell Units 1 and 2 were retired in 2023, the planned outage schedule for the units would also be adjusted in order to allow for necessary projects to be completed while minimizing the number of scheduled outage days over the remaining lifespan of the units.” 8 TR 1168-1169.

Mr. Comings noted that the Company was planning to increase spending on Campbell Units 1 and 2 in Case No. U-20134, compared to what was modeled in its IRP, and claimed concern that “the Company is ramping up investment in these units and once again delaying a possibly economic retirement decision.” 8 TR 1848. The contention is meritless. As Mr. Kapala explained, after the Company had already begun its modeling for this case, it “identified several additional projects that are needed to maintain reliability at Campbell Units 1 and 2. Once the Company’s IRP modeling indicated that the best option for the Company would be to operate Campbell Units 1 and 2 until 2031...it became even clearer that this additional reliability work was needed during the 2019 electric rate case test year.” The major maintenance work at issue is necessary for the safe and reliable operation of Campbell Units 1 and 2. 8 TR 1125-1126. Mr. Comings’ theory, on the other hand, was unsupported and the Commission should reject it.

According to Mr. Comings, his analysis indicated that the Company's customers would benefit if it retired Campbell Units 1 and 2 in 2023, or at least retired Campbell Unit 2 in 2023. 8 TR 1863. The Commission should reject both proposals. As discussed above, and reiterated by Mr. Kapala (8 TR 1170-1171), if Campbell Units 1 and 2 both retired in 2023, then the Company would incur separation activity costs at Campbell Unit 3 to enable its continued operation. Campbell Units 1 and 2 would not enter the cold and dark phase, and it would be difficult to pursue any redevelopment opportunities at the site to make up for the lost economic activity in the community when the units retire. The Company modeled the cost of the separation activity work at \$10 million, but because the Company is not recommending the retirement of Campbell Units 1 and 2, it did not conduct a formal study of the full separation costs. Ten million dollars is an estimated minimum, and actual costs could be substantially higher. 8 TR 1132-1133. Again, Mr. Comings does not appear to have accounted for these critical issues in his analysis.

Regarding Mr. Comings' proposal that, "[a]t a minimum, the Company should revise its PCA to ensure the retirement of Campbell 2 in 2023" (8 TR 1863), this proposal is equally problematic. As discussed above, and reiterated by Mr. Kapala (8 TR 1171-1172), the two units operate as a single facility with a common staff and common internal systems, and the Company is generally able to realize efficiencies by operating Campbell Units 1 and 2 as a single facility due to equipment configuration and employee skillsets. To retire one of the units while the other remained in operation, the Company would effectively be operating a single unit with the same resources that previously operated two units, representing a substantial loss in efficiency. Further, while the previously described separation activity work at Campbell Unit 3 would not be required if only Campbell Unit 2 were required, there would be other work required to isolate

Campbell Units 1 and 2 from one another, including but not exclusively, the house service water and air systems, electrical bus work, and the emergency generator. As the PCA does not call for the Company to separate Campbell Units 1 and 2 from one another, the Company did not develop any projections of the costs of this work, but Mr. Comings failed to account for any of these operational and engineering issues in his proposal. 8 TR 1171-1172.

(e.) **Historical And Projected Capacity Factors**

At 8 TR 1849-1850, Mr. Comings provides a comparison of 2017 and year-to-date 2018 actual Campbell Unit 1 and 2 capacity factors with projected 2017 and 2018 Campbell Unit 1 and 2 capacity factors and suggests that the difference between these values provides evidence that the model accuracy should be questioned. However, Mr. Comings' analysis of the capacity factors for Campbell Units 1 and 2 is incomplete, and therefore fails to establish inaccuracy in the Company's modeling.

Mr. Comings did not provide a meaningful analysis of historical and projected capacity factors because he did not address any of the many variables that could be different between actual production and forecasted production in 2017 and 2018. Mr. Clark explained that the dispatch of the Company's coal-fired generation is highly dependent on market conditions and planned outages. 7 TR 953-954. Therefore, to appropriately compare historical and project capacity factors for Campbell Units 1 and 2, it would be necessary to provide actual fuel prices for coal and natural gas, actual system loads, and actual unit outages for 2017 and 2018, then run the model and compare the results. 7 TR 954. Mr. Comings' approach, which simply compares 2017 and 2018 actual results to 2017 and 2018 projected results, is overly simplistic and completely inaccurate. Furthermore, Mr. Clark noted that, while coal-fired generation dispatch is important, it is not the sole economic determinant in the analysis of coal-fired generation

operations. The net value provided by a resource to customers is the most important metric for evaluating retirement economics. 7 TR 954.

**(f.) Alternative Modeling**

Based on modeling performed by MEC witness Evans, Mr. Comings recommended replacing the capacity associated with Campbell Units 1 and 2 with market purchases of ZRCs or with a mix of wind and solar resources to be online in 2023. 8 TR 1857-1862. Mr. Comings presented the results of MEC's modeling in the BAU, ET, and EP scenarios, using both Consumers Energy and AEO natural gas projections, and assuming varying levels of CONE. 8 TR 1859, Table 7. MEC's modeling results vary, including a potential increase in customer costs in the amount of \$48 million NPV as a result of the retirement of Campbell Units 1 and 2 in 2023, to a potential savings of \$774 million NPV. 8 TR 1859.

In response to MEC's retirement recommendations for Campbell Units 1 and 2, Company witness Walz narrowed the consideration of MEC's modeling results to capacity prices of 50% and 75% of CONE and to Consumers Energy natural gas prices. 6 TR 514. The Consumers Energy natural gas price is the natural gas assumption that the Company used in the Medium 4 Retirement Analysis, and 50% and 75% of CONE represent the range of capacity prices assumed by MEC and Consumers Energy. 6 TR 514. In examining just these assumptions, MEC's economic results to replace Campbell Units 1 and 2 capacity vary from a potential increase in customer costs of \$93 million NPV to a potential cost savings of \$464 million NPV. 6 TR 515; Exhibit A-104 (STW-26), lines 4-5. MEC's economic results to replace Campbell Unit 2 in 2023 vary from a potential cost savings of between \$35 million NPV to \$408 million NPV. 6 TR 515; Exhibit A-105 (STW-27), lines 4-5. As discussed in Section IV.A.4.d of this Initial Brief, relying on the purchase of ZRCs to replace Campbell Units 1 and 2

capacity is inappropriate, and thus the MEC modeling results that Consumers Energy presented in lines 4 and 5 of Exhibits A-104 (STW-26) and A-105 (STW-27) only indicate MEC's build portfolio.

Ms. Walz identified two significant errors in MEC's Strategist modeling, which when corrected, indicated that Mr. Comings overstated the projected savings for the 2023 retirement of Campbell Units 1 and 2 by \$274 million NPV and the projected savings for the 2023 retirement of Campbell Unit 2 by \$223 million NPV. 6 TR 516. The first error is that MEC failed to update all of the fixed costs in the 2023 retirement sensitivities, and thus overstated the savings for early retirement both as to future capital investments and O&M expenses. 6 TR 516. Capital costs modeled for years 2018 through 2023 corresponding to a 2023 retirement assumption are higher than capital costs for years 2018 through 2023 corresponding to a 2031 retirement assumption to account for the full recovery of capital investments by the end of the operating life of the units. 6 TR 517. This results in an increase in the cost of retiring Campbell Units 1 and 2 in 2023 of \$63 million NPV and an increase in the cost of retiring Campbell Unit 2 in 2023 of \$42 million NPV. MEC's analysis also did not reflect that if Campbell Units 1 and 2 or just Campbell 2 are retired, some of the site-common O&M expenses associated with those units would be re-allocated to the remaining units, such as Campbell Unit 3. 6 TR 517-518. This results in an increase in costs for the 2023 retirement of Campbell Units 1 and 2 of \$17 million NPV and an increase in costs for the 2023 retirement of just Campbell Unit 2 of \$28 million NPV. 6 TR 518.

After correcting the failure to update fixed costs, and continuing to focus on the 50% to 75% CONE and Consumers Energy natural gas price assumptions, the economic results to replace Campbell Units 1 and 2 in 2023 are changed to vary from a potential increase in

customer costs of \$173 million NPV to a potential cost savings of \$384 million NPV. 6 TR 519; Exhibit A-104 (STW-26), lines 9-10. Similarly, the economic results to replace just Campbell Unit 2 in 2023 are changed to vary from a potential cost increase of \$2 million NPV to a potential cost savings of \$371 million NPV. 6 TR 519; Exhibit A-105 (STW-27), lines 9-10.

The second modeling error is that MEC's modeling understated the supply-side costs to replace Campbell Units 1 and 2. 6 TR 519. The Strategist resource optimization runs evaluating the replacement of capacity for Campbell Units 1 and 2 in 2023 with supply-side resources selected an incremental 700 MW of solar capacity and an incremental 800 MW of wind capacity to be placed in service in 2023. 6 TR 519. However, MEC's modeling overstated the PTCs and ITCs available for these resources under current law, which resulted in understating the replacement costs of these resources and overstating the cost savings associated with retiring the Campbell units in 2023. 6 TR 519.

MEC recommended placing 800 MW of wind resources into service in 2023, which would be expected to be eligible for a 40% PTC. 6 TR 519. However, MEC modeled costs that assumed PTC levels of 60% to 80%, which are more consistent with wind resources placed into service in 2021 or 2022, not 2023. 6 TR 519-520. This results in costs for the additional wind capacity that are \$187 million NPV too low. 6 TR 520. MEC also modeled 400 MW of incremental solar in 2023, but assumes construction of those resources would begin in 2019 to receive 30% ITC. 6 TR 520. This faster ramp up of solar is not practical, and correcting the ITC levels for the initial 400 MW of solar increases costs for the 2023 retirement of Campbell Units 1 and 2 by \$8 million. 6 TR 520.

After correcting both the failure to update the fixed costs and the understated solar and wind replacement costs, the economic results to replace Campbell Units 1 and 2 in 2023 vary

from a potential increase in customer costs of \$367 million NPV to a potential cost savings of \$190 million NPV. 6 TR 520; Exhibit A-104 (STW-26), lines 14-15. Moreover, the economic results to replace just Campbell Unit 2 in 2023 vary from a potential cost increase of \$189 million NPV to a potential cost savings of \$185 million NPV. 6 TR 520; Exhibit A-105 (STW-27), lines 14-15. When considering just the scenario that the Company used in the Medium 4 Retirement Analysis (BA UCE at 75% of CONE capacity value), the above corrections to MEC's modeling indicate that under the PCA, the retirement of Campbell Units 1 and 2 in 2023 would increase customer costs by \$344 million NPV, and the retirement of just Campbell Unit 2 in 2023 would increase customer costs by \$189 million NPV. 6 TR 521.<sup>24</sup> Thus, the modeled economic results of retirement of Campbell Units 1 and 2 in 2023, or just Campbell Unit 2 in 2023, do not support MEC's recommendation to modify the PCA to plan for the retirement of any of the Campbell Units 1 and 2 in 2023.

In addition to the flaws noted above, MEC's alternative modeling, which proposes to add 800 MW of wind generation, fails to consider that this wind generation would need to be built in addition to: (i) the 550 MW of wind generation planned as part of the RE Plan; (ii) 100 MW of solar generation planned as part of the RE Plan; (iii) 600 MW of solar generation planned as new resources being ramped up to replace 2030 era retirements; and (iv) all of the demand-side resources identified in the PCA. Mr. Clark explained that relying on the ZRCs provided by this new incremental wind in place of Campbell Units 1 and 2 would mean significant cost separation risk and would also present more risk related to maintaining the LCR, when compared to the

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<sup>24</sup> These NPV costs reflect an analysis of the retirement of Campbell Units 1 and 2 in 2023 in addition to retirement of Karn Units 1 and 2 in 2023. As such, these NPV costs are higher than those reflected in the Company's analysis of the retirement of Campbell Units 1 and 2 in 2023 *without* also retiring Karn Units 1 and 2. 6 TR 521. As more capacity is retired, the replacement cost of the incremental resources increases. 6 TR 521-522. In the PCA, Karn Units 1 and 2 are replaced with low cost demand-side resources and incremental additions of solar; adding the retirement of Campbell Units 1 and 2 in 2023 requires new wind and solar resources, which are significantly more expensive than DR. 6 TR 522.

resource mix proposed in the Company's PCA. Finally, when correcting the capacity value assumptions including in MEC's modeling to 75% MISO CONE, as discussed above, and discarding the idea of building 800 MW of new out-of-state wind resources, Mr. Clark explained that MEC's recommendation to retire Campbell Units 1 and 2 in 2023 would not provide savings to customers. 7 TR 955.

**(ii.) Response To SEIA**

Beginning at 8 TR 1974, SEIA witness Lucas claims that retiring Karn Units 1 and 2 in 2021 would save customers \$80 million compared to retiring the units in 2023. This recommendation should be rejected because it fails to consider the value provided by the Karn Units 1 and 2 for those two years of operation.

Mr. Clark explained that, while the incremental expense to operate Karn Units 1 and 2 for Planning Years 2021 and 2022 may be \$80 million, customers would receive the energy and capacity produced by the plants for those years in exchange for those costs. 7 TR 956. As illustrated in the Corrected Coal Price Retirement Analysis figure above, when using corrected coal prices in the Company's Medium 4 Retirement Analysis, the difference in customer savings between retiring Karn Units 1 and 2 in 2021 and 2023, is only \$17 million. 7 TR 956. Mr. Clark explained that this incremental cost is worth offsetting the risks related to retiring Karn Units 1 and 2, as discussed in Section III.C. of this Initial Brief, and is the reason that 2023 was the selected retirement year. 7 TR 956.

**(iii.) Response To MCV**

Beginning at 9 TR 2923, MCV witness Medine argues that the Company's Medium 4 Retirement Analysis did not reflect offers to reduce rail rates and was not based upon the AEO natural gas price forecast as required. Ms. Medine further argues that the Company should have considered the cost implications of the remaining book balance of the units and that the

Company failed to consider all potential retirement years. 9 TR 2924-2925. These criticisms are baseless and should therefore be rejected.

Ms. Medine's criticism regarding reduced rail rates and the AEO natural gas price forecast fail to establish any flaws in the Company's analysis. Mr. Clark explained that the reduced rail rates referenced by Ms. Medine are not available at this time and any analysis based on reduced rail rates would be too speculative. 7 TR 956. Furthermore, contrary to Ms. Medine's claim, the Company did conduct an analysis using AEO natural gas prices by considering the economic impact of retiring Karn Units 1 and 2 in 2023 versus 2031 in all scenarios, including the AEO gas price scenarios.<sup>25</sup> 7 TR 957. The results of these analyses were provided in Exhibit A-20 (STW-11).

Moreover, since the remaining book balance represents investments already made and approved for recovery from customers and these costs should not be considered in the economic evaluation of early retirement versus continued operation. 7 TR 958. Mr. Clark explained that early retirement decisions should be made based on a comparison of the customer expenses required to deliver the projected energy and capacity from the units to the value of the energy and capacity projected to be delivered from the units. Only after the economic analysis is complete, it is appropriate to consider the impact, if any, the recovery of the remaining book balance has on the decision. 7 TR 958.

Finally, Ms. Medine's criticism regarding the consideration of additional retirement years fails to consider the limitations of modeling software and the uniqueness of the Company's generation portfolio. Mr. Clark explained that the payment structure of some of the Company's

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<sup>25</sup> It should further be noted that the parameters of the Company's Medium 4 Retirement Analysis were dictated by the parameters ordered by the Commission in its March 29, 2018 Final Order in Case No. U-18322. For the purposes of this analysis, the Commission's ordered retirement analysis parameters was viewed as superseding the requirements in the MIRPP, as approved in Case No. U-18418.

PPAs prevents Strategist from determining an optimal retirement year. 7 TR 958. Therefore, the Company identified discrete years to evaluate, with 2023 serving as a clear break point because of the material environmental investments required to continue operation beyond this year. 7 TR 958. Mr. Clark explained that, due to these investments, if the economics were not favorable for a 2023 retirement, it stands to reason that the economics would not be favorable for a 2024 through 2031 retirement. 7 TR 958.

**(iv.) Response To ABATE**

At 8 TR 2099-2101, ABATE witness Pollock attempts to support the continued operation of Karn Units 1 and 2 by pointing to the stranded costs that result from retiring these units, the potential for the realization of extreme scenarios, the decision to replace existing resources with front-end loaded resources, and the optionality of actual retirement in the early 2030's. While there is some merit to certain arguments presented by Mr. Pollock, he has failed to support the continued operation of Karn Units 1 and 2 beyond 2023.

Mr. Clark explained that Mr. Pollock's concern regarding stranded costs is of minimal relevance. 7 TR 959. The Company's Medium 4 Retirement Analysis identified that the ongoing expenses were nearly equal to the ongoing value provided by these facilities. Therefore, if the Company can obtain the energy and capacity that would have otherwise been provided by these facilities from other sources at lower cost, it would be in the customers' best interest to obtain the lower cost energy and capacity, and also continue to collect the stranded costs associated with these facilities from customers. 7 TR 960.

Mr. Pollock's concern regarding the front-end loading of the resources replacing the retiring units is also not material to the Company's retirement decision. Mr. Clark explained that the decision to replace the retiring facilities with front-end loaded resources (i.e., solar resources) is a function of these resources being the most economic option and the recovery mechanism for

these resources. 7 TR 960. It would not be reasonable to deviate from a low cost resource option just to avoid front-end loaded costs, as Mr. Pollock seems to suggest. 7 TR 960.

While Mr. Pollock's concerns regarding stranded costs and front-end loading of resources have little merit in relation to the Medium 4 Retirement Analysis, Mr. Clark explained that Mr. Pollock is correct regarding the fluid nature of the Company's assumed retirement dates for its existing resources. 7 TR 960. The Company may be able to stagger retirements in the early 2030's to alleviate some of the execution risk associated with the MCV PPA termination and the retirement of Campbell Units 1 and 2 and Karn Units 1, 2, 3, and 4. 7 TR 960. However, the Company would still need to replace nearly 3,600 MW of generation resources. Mr. Clark explained that, regardless of the early retirement of Karn Units 1 and 2, the Company would anticipate implementing the capacity addition plan included in the PCA so that there will be sufficient time to replace the existing generation identified above. 7 TR 960.

**b. Medium 4 Investment And Timing Of Retirement**

**(i.) Response To SEIA**

SEIA witness Lucas contended that the Company should retire Karn Units 1 and 2 in 2021, instead of in 2023 as in the PCA. 8 TR 1974. For all the reasons provided below, Mr. Lucas' proposed 2021 retirement for Karn Units 1 and 2 is based on invalid assumptions, ignores significant costs and other factors, and would result in increased execution risks. The Commission should therefore reject his position.

In an attempt to support a 2021 retirement for Karn Units 1 and 2, Mr. Lucas asserted that any increased costs or risks associated with a 2021 retirement date would be more than offset by savings to the Company and its customers, which he calculated to be \$77,839,000. 8 TR 1975. Mr. Lucas' reasoning was flawed, as he overstated the difference in avoidable costs between a 2023 retirement date and a 2021 retirement date for Karn Units 1 and 2. Mr. Kapala reviewed the table provided by Mr. Lucas at 8 TR 1975, and testified that Mr. Lucas improperly included base O&M costs as part of his savings offset. Mr. Kapala explained:

“The actual projects, and therefore the actual costs, that could be avoided by retiring Karn Units 1 and 2 in 2021 instead of 2023 are represented by the capital cost and major maintenance cost line items in Mr. Lucas' table. It is inaccurate to also include the base O&M expenses in this analysis, as it implies that the base O&M expenses over two years could be entirely avoided through a 2021 retirement. On the contrary, as discussed on page 55, lines 1 through 11 [8 TR 1152], of my direct testimony, the Company's Working Agreement covering Operating, Maintenance, and Corporation ('OM&C') employees guarantees all eligible OM&C employees a position at their current respective wage within 60 miles of the Karn site, and the Company also intends to offer all exempt and non-exempt employees at the Karn site other positions within the Company. Therefore, even if Karn Units 1 and 2 were retired in 2021, the Company's base O&M expenses for the salaries of those employees would not simply go away; those employees would still be on the Company's payroll, even if located at other sites.” 8 TR 1157-1158.

Thus, Mr. Lucas' analysis did not accurately capture the savings that the Company would realize by retiring Karn Units 1 and 2 in 2021 instead of 2023. The appropriate difference in savings between the 2023 and 2021 retirement dates for Karn Units 1 and 2 is actually \$17,569,000, as Mr. Kapala explained:

“As noted above, the actual avoidable costs are defined by the capital and major maintenance projects that can be avoided through an earlier retirement. The table on page 25, line 1, of Mr. Lucas' direct testimony [8 TR 1975], shows that the difference in capital and major maintenance costs between the two retirement dates is \$17,569,000. That is the appropriate number to use when comparing the two retirement dates; for example, this difference was correctly cited by MEC witness Comings on page 12, lines 1 through 3 [8 TR 1837], of his direct testimony, reinforcing the numbers shown in Figure 4 of Company witness Thomas P. Clark's direct testimony.” 8 TR 1518.

Mr. Lucas also claimed that if Karn Units 1 and 2 retired in 2021 instead of 2023, “the separation activity costs may exceed the currently planned \$30 million and that this could reduce the benefit of retiring the plants earlier. However, given the magnitude of the expected savings and projected incremental costs, the unanticipated increase in expenses would have to be massive to outweigh the financial benefits of retiring the units in 2021.” 8 TR 1976-1977. This analysis was also flawed. As Mr. Kapala testified, Mr. Lucas failed to account for environmental costs and related execution risks:

“First, the financial benefit of retiring the units in 2021 is much less than Mr. Lucas states, as I have already discussed in this rebuttal testimony. Second, the \$30 million total that Mr. Lucas references only applies to separation activity work to allow Karn Units 3 and 4 to continue operation after Karn Units 1 and 2 are retired. This \$30 million does not include any other costs related to the decommissioning of Karn Units 1 and 2, particularly related to environmental clean-up, an issue that Mr. Lucas himself acknowledges on page 26, line 22, of his direct testimony [8 TR 1976]. As I discuss on page 45, line 12 through page 46, line 2, of my direct testimony [8 TR 1143], the Company will have to complete significant work to ensure that Karn Units 1 and 2

comply with environmental regulations for retirement, and the Company is fully committed to preventing any environmental contamination. Mr. Lucas fails to account for page 45, lines 19 through 21, of my direct testimony [8 TR 1142], where I stated that: ‘[i]f the Company does not have sufficient time to do this cleaning, it runs the risk of significantly increased clean-up costs in order to ensure that the Company does not violate emissions limits and completes all necessary clean-up work,’ referring to regulatory limits on emissions into local waterways throughout the prolonged cold and dark period. As I further state on page 47, lines 8 through 12, of my direct testimony [8 TR 1144], a 2023 retirement date allows adequate time for environmental clean-up, while a 2021 retirement date would instead increase risk and costs.” 8 TR 1159.

As a result, the Commission should reject Mr. Lucas’ analysis, as he cited only to the risk of increasing separation activity costs, and did not fully capture the potential for increased costs with a 2021 retirement date, when there are multiple areas in which costs would likely increase. *Id.* Thus, Mr. Lucas understated the potential for increased costs just as he overstated the potential savings of a 2021 retirement date.

Mr. Lucas’ also failed to account for other operational or engineering risks that a 2021 retirement date for Karn Units 1 and 2 would present. Mr. Kapala stated in his direct testimony that it would not be feasible to complete separation activity work at Karn Units 3 and 4 by May 31, 2021. 8 TR 1144. Mr. Kapala reiterated this point in his rebuttal testimony, and noted that he had also provided this analysis in discovery. 8 TR 1160. Mr. Lucas failed to account for the fact that his proposal was not feasible from a timing perspective. Mr. Lucas also failed to account for the fact that, even if the Company retired Karn Units 1 and 2 in 2021, those units would still have to continue to operate pending their separation from Karn Units 3 and 4, as Mr. Kapala explained:

“[E]ven if Karn Units 1 and 2 stopped generating electricity for customers on May 31, 2021, they would not be able to enter the cold and dark phase until likely some point in 2022, because certain systems would need to continue to operate to allow the

continued operation of Karn Units 3 and 4 while separation activity work was ongoing, such as the demineralizer and soot-blowing air systems. Karn Units 3 and 4 currently rely on Karn Units 1 and 2 for several auxiliary systems, as described beginning on page 33, line 18, of my direct testimony [8 TR 1130]. Additional plant operations staff, beyond those needed for normal operation of Karn Units 3 and 4, would need to continue working at the site to operate and maintain these systems.

“During the period between the cessation of electric generation at Karn Units 1 and 2 and when those units go cold and dark, Karn Units 1 and 2 will be required to continue operating their auxiliary systems for Karn Units 3 and 4 until the separation activity projects at Karn Units 3 and 4 are complete. External portable equipment will also be required to support all four Karn units until the separation activity projects are complete. Therefore, until the separation activity projects are complete, Karn Units 1 and 2 cannot enter the cold and dark phase and Karn Units 3 and 4 would not be able to operate independently. In explaining his reasoning for why a 2021 retirement date is preferable, Mr. Lucas does not discuss at all how this issue could be addressed.” 8 TR 1160.

Mr. Lucas also have short shrift to the importance of the Company’s employee retention, transition and separation plans, stating that: “[t]he Company does not specify why it needs 36 months to complete this transition, other than to mention that ‘many employees will need to be retrained for new jobs.’” 8 TR 1977. As Mr. Kapala pointed out, Mr. Lucas appears to have misunderstood the Company’s employee transition plan, since he referred to it as a “36-month employee retention and separation plan” with a cost of up to \$10 million. 8 TR 1977. The \$10 million cost would only cover: (i) retention bonuses for employees at the Karn site who remain in their positions for the 36-month period leading up to the retirement of the units; and (ii) separation payments to employees who leave employment with the Company after the retirement of the units. 8 TR 1151, 1161.

Mr. Lucas’ assertion that the Company did not specify why a 36-month transition is needed is also incorrect, and appears to conflate two related but separate issues. The 36-month

period, in the context of the retention bonuses, is the time employees must work to qualify for said bonuses. The “36-month employee retention and separation plan,” as referred to by Mr. Lucas, is related but separate from the Company’s plan to retrain employees as necessary, which would also be over a 36-month period. 8 TR 1161. The Company decided to use a 36-month period in determining eligibility for retention bonuses in order to ensure a stable workforce for an adequate period at the Karn site as Karn Units 1 and 2 are prepared to be retired, and discourage employees from seeking alternative positions before the retirement process is complete. 8 TR 1141, 1162. The 36-month time period is necessary to ensure that employees can be retrained while also continuing to operate Karn Units 1 and 2 safely and reliably. 8 TR 1152-1153.

Unlike during the Company’s retirement of the Classic 7 units, in which the Company could place most affected employees at other generation sites, in this situation the Company has very few other locations – and no locations within 60 miles of the Karn site – where affected employees could be relocated and continue using their current training and expertise. Therefore, in conjunction with continuing to operate Karn Units 1 and 2, these employees will be afforded the opportunity for retraining. The Company must be deliberate in how this is accomplished, as a limited number of employees can be removed from operation activities for training at any given time while the Company also continues to safely operate Karn Units 1 and 2. 8 TR 1162.

A 2021 retirement date would unduly compress the time for employee transitions and reduce the effectiveness of the process, which includes retraining as necessary for employees who are not separated from the Company. 8 TR 1144. In order to ensure the safe and reliable operation of Karn Units 1 and 2, it is essential that employees remain in their positions through the closure date with confidence that they will be able to move on to other positions within the

Company afterwards, a principle that the Company applied very effectively when preparing to retire the Classic 7 coal generation units in 2016. 8 TR 1163. Mr. Kapala testified that the Company's observations of other utilities have shown that if employees lack this confidence, it can have various deleterious impacts on safety and reliability, making the timely retirement of a plant difficult. 8 TR 1163.

Mr. Lucas also claimed that the Company's MATS investments did not justify keeping Karn Units 1 and 2 in operation until 2023 because: (i) the costs are sunk; (ii) the investments do not completely eliminate mercury and air toxins emissions; and (iii) the investments do not reduce carbon dioxide emissions. 8 TR 1977-1978. This claim is without merit. As Mr. Kapala explained:

“While the MATS investments are sunk costs, they do not completely eliminate pollutant emissions, and they are not intended to affect carbon dioxide emissions, that is not the point that I argued on page 47, line 21 through page 48, line 3, of my direct testimony [8 TR 1144]. The Company does not advocate operating Karn Units 1 and 2 until 2023, instead of until 2021, in order to maximize the *environmental* benefits of the MATS investments. The purpose of the MATS investments was to allow Karn Units 1 and 2 to continue operating in order to continue providing *energy* and *capacity* benefits to the Company's customers. Retiring the units in 2021 instead of 2023 would reduce the energy and capacity benefits that the units provide to customers, by basically eliminating two full years of these energy and capacity benefits. In other words, although the MATS investments are sunk costs, operating the units until 2023 instead of 2021 allows the Company to better maximize the usefulness of those investments for producing energy and capacity benefits.” 8 TR 1165.

As a result of the foregoing, Mr. Lucas' proposed 2021 retirement for Karn Units 1 and 2 would not produce the cost savings that he identified, would result in increased execution risks and increased costs. The Commission should reject it.

**(ii.) Response To ABATE**

ABATE witness Pollok asserted that there are no compelling reasons to retire Karn Units 1 and 2 prior to their design lives. 8 TR 2101. According to Mr. Pollok, “evolving technology is...making fossil fuel generation more cost efficient.” 8 TR 2099. He further stated that “[f]ossil fuel resources are also undergoing technological changes that result in lower net heat rates and emissions. It is possible that unanticipated technological improvements in fossil fuel generation, coupled with lower projected natural gas prices, could be less costly and less impactful on rates.” 8 TR 2112. Mr. Pollock, however, did not specify any particular “evolving technology” or “technological changes” to support his belief. As such, Mr. Pollock’s unsupported speculations do not in any way impugn the Company’s PCA.

Mr. Pollock also stated that, although the Company cited the impact on employees and the community to support its proposal to retire Karn Units 1 and 2 in 2023, “both employees and the affected communities are already aware” of the Company’s plan and therefore “[t]his is not a reason for early retirement.” 8 TR 2134. These statements reflect a fundamental misunderstanding of the Company’s position. In support of his position, Mr. Pollock cited the testimony of Company witness Blumenstock (6 TR 250), that “retirement of Karn Units 1 and 2 is proposed for 2023 over 2021 to minimize risks associated with employee transition, developing backfill capacity, and planning for community and employee transition.” Mr. Blumenstock’s cited testimony addressed concerns over employee and community transition to explain why retiring Karn Units 1 and 2 in 2021 would be too early, and why 2023 is a more reasonable date. It had nothing to do with moving the retirement date of Karn Units 1 and 2 forward from 2031.

**c. Independent Analysis**

MEC witnesses Evans and Comings both provided criticisms of the independent analysis of the Company's Medium 4 Retirement Analysis, as performed by Mr. Adkins. Specifically, Mr. Evans and Mr. Comings criticize Mr. Adkins' consideration of coal costs, capacity replacement, and modeling time horizon. For the reasons discussed below, these criticisms should be rejected.

As explained above, subsequent to the filing of the Company's IRP, the Company identified a coal price error in its modeling. This coal price error also impacted Mr. Adkin's independent retirement analysis. On account of this error, Mr. Adkins updated his analysis to include corrected coal prices, as provided in Exhibits A-100 (CFA-2) and A-102 (CFA-4). This updated analysis determined there is a change in the values provided by retiring the Medium 4 units but this change did not impact Mr. Adkins' original conclusions and recommendation. 6 TR 332-333.

Mr. Adkins explained that the only meaningful change to his retirement analysis, when using the updated coal price forecast, was a minor change to the optimal plan for the retirement of Campbell Units 1 and 2. 6 TR 333. The optimal plan was to retire Campbell Units 1 and 2 in 2031 in Mr. Adkins' original analysis and in the revised analysis, the optimal plan changed to retiring Campbell Units 1 and 2 in 2029. 6 TR 333. Mr. Adkins explained that, when considering the corrected coal prices, there is still a value to retiring Karn Units 1 and 2 early and still a cost of retiring Campbell Units 1 and 2 early. 6 TR 333. Therefore, Mr. Adkins' maintains the recommendation that the Company should consider environmental retrofits at Campbell Units 1 and 2 and continue operations until their planned retirement date of May 2031.

Mr. Adkins further recommended that the Company continue to monitor market developments to determine if there is any value to retiring these units early.

In addition to the above, Mr. Adkins refuted MEC's arguments related to the capacity replacements considered in his retirement analysis. Contrary to Mr. Comings' assertion (see 8 TR 1852), Mr. Adkins explained that his modeling was not limited from choosing lower cost capacity replacement options. The table provided at 6 TR 322 identifies the technologies that were available in terms of their Marginal Cost of Firm Capacity (2017 \$/kW). Mr. Adkins explained that, as illustrated in this table, CT and CC units were the two least cost marginal capacity units. 6 TR 335. Since Mr. Adkins used these resources in his analysis, it is untrue that Mr. Adkins' modeling was limited from choosing lower cost replacement options.

It is also incorrect that Mr. Adkins' analysis is contradictory to the Company's Medium 4 Retirement Analysis, as Mr. Evans suggests. 8 TR 1818. Mr. Adkins explained that his analysis was centered around the economics of retiring any combination of Medium 4 units and replacing these units with the least cost marginal capacity resources available. 6 TR 335. Furthermore, Mr. Evans' criticism that Mr. Adkins did not utilize "an actual capacity replacement plan" should also be rejected. Mr. Adkins retirement analysis considered the least cost marginal capacity resources, which is what generating units are replaced with when they retire. 6 TR 335.

Mr. Comings' criticism that Mr. Adkins failed to model the Medium 4's projected costs and revenues through the 2040 end date that the Company used for its IRP should be rejected because it fails to consider the underlying economic theory driving the Company's modeling. See 8 TR 1851. Mr. Adkins explained that the Strategist software uses the Economic Carrying Charge as the representation of capital costs for the optimization, also known as the Value of

Deferral. 6 TR 336. Mr. Adkins explained how this analysis is independent of a time horizon as follows:

“This economic stream assumes an infinite replacement in kind where the asset’s value increases as a result of inflation and cost escalation. This analytical paradigm is perfect for evaluating different assets with different life cycles and this method is generally accepted throughout the industry and used throughout the world. Therefore, the analysis is independent of time horizon.” 6 TR 336.

Furthermore, Mr. Adkins explained that a 2040 time horizon, as supported by MEC, would not change his Medium 4 analysis. This is because all of the Medium 4 units will be retired by 2032 and replaced with new resources. 6 TR 336. Therefore, no decisions beyond 2032 would be impacted with a 2040 time horizon.

#### **6. Recovery Of Unrecovered Book Balance Of Karn Units 1 And 2**

Staff witness Proudfoot, presented Staff’s position regarding the Company’s request for approval to recover the unrecovered book value of Karn Units 1 and 2, and asserts that said request by the Company is “outside the reasonable scope of an IRP.” 9 TR 2547. As Mr. Proudfoot argued:

“A reasonable scope for utility-filed IRPs in Michigan includes a *forward-looking plan spanning at least the next fifteen years that includes existing and proposed new resources to meet the utility’s expected customer load, reliability requirements and environmental regulations on a going-forward basis . . .* an IRP must identify the utility’s capacity and energy needs and all of the resources – supply- and demand-side, utility owned, and purchased resources – that the utility plans to use to meet its current and projected needs. The IRP must also include data about the utility’s existing generation fleet *and analyze the cost and viability of all reasonable options available to meet projected energy and capacity needs.*” (Emphasis added.) 9 TR 2547.

First, as Mr. Proudfoot himself notes, an analysis of the *costs* of all reasonable options available to meet projected energy and capacity needs is an important part of an IRP and within

the scope of an IRP. As discussed above, Company witness Myers demonstrated the advantages and benefits of regulatory asset treatment, which assumes that the remaining net book value for Karn Units 1 and 2 will be removed from plant-in-service accounts, and recorded in a regulatory asset in the next general electric rate case. See 7 TR 1043-1048. In fact, as demonstrated by Ms. Myers, and unrefuted by any party, regulatory asset 2031 treatment, which was described as “essential” to the Company’s PCA, has lower revenue requirements, lower NPV, and reduced rates over that of traditional retirement accounting. 7 TR 1043, 1048.

Second, Mr. Proudfoot noted that an IRP is a “*forward-looking plan spanning at least the next fifteen years that includes existing and proposed new resources to meet the utility’s expected customer load, reliability requirements and environmental regulations on a going-forward basis.*” (Emphasis added.) As presented in the direct testimony of Company witness Blumenstock, the Company plans to operate Karn Units 1 and 2 through 2031, rather than retire these units in 2023, absent the assurance of full recovery of the remaining book balance of Karn Units 1 and 2 – this falls squarely in a discussion of existing and proposed resources. Mr. Proudfoot argues that a “forward-looking plan” spanning at least the next fifteen years “should” evaluate different options for “going-forward costs,” as opposed to expenditures that were made in the past and will continue to exist regardless of changes in the outcome of “forward-looking plans.” He, however, provides no legal basis for his attempt to exclude existing costs in an analysis of the use of existing resources, and costs related to reasonable options to meet projected energy and capacity needs.

Further Mr. Proudfoot’s use of words such as “forward-looking” and “going-forward” are not found in the IRP statute and have been artificially added to Staff’s proposed explanation of the scope of an IRP. This language choice appears to be intended to reshape the intent and actual

articulated direction of the statute, which actually provides for analyses of “costs” related to “existing” electric generation facilities. In fact, Section 6(t)(5)(k) provides for,

“An analysis of the *costs*, 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.” (Emphasis added.)

Because *existing* resources and *costs* associated with existing resources are proper subjects of an IRP, as articulated in the statute and so indicated by Mr. Proudfoot, the analysis of unrecovered book value of Karn Units 1 and 2 are, contrary to Staff’s assertion, clearly within the global resource planning scope of an IRP.

While Staff suggests that “[s]eparating the request for approval of the unrecovered book value of Karn unit 1 and Karn unit 2 from the IRP case should not impact the Company’s ability to retire the plans early and implement the PCA,” this is contrary to the intent of the IRP to provide a holistic approach to resource planning, which as discussed above, includes costs relating to existing electric generation facilities. Further, as explained by Ms. Myers in her rebuttal testimony, the Company’s regulatory asset proposal provides a vehicle and advantageous method for assurances of the full recovery of the remaining book balance of Karn Units 1 and 2. 7 TR 1049. She added, “[a]pproval of the Company’s regulatory asset proposal in this proceeding is administratively efficient and provides certainty and alignment with the decisions on the Karn Units 1 and 2 replacement plans.” 7 TR 1049. Thus, because addressing costs related to existing generation facilities is clearly articulated as being within the scope of an IRP, and “[b]ecause we can only speculate as to timing of future proceedings that may provide for next opportunity to obtain regulatory asset approval, providing for approval of the regulatory asset in these proceedings is necessary.” 7 TR 1049.

**7. Competitive Bidding Process And Determination Of PURPA Avoided Costs**

**a. Competitive Bidding**

The Company proposes to utilize a competitive solicitation process to select any new supply-side capacity resources. 8 TR 1251. The purpose of the competitive solicitation process is to ensure that costs incurred are the most reasonable and allow for cost competitive rates for customers. By adopting a competitive bidding process, it helps to ensure that the costs and risks of all submitted proposals are compared against each other, that equitable consideration is given to all bidding parties, and that the projects and resources selected result in cost-competitive rates for customers. This provides an equitable playing field for all submitting parties, whether or not the resource is Company-owned. 8 TR 1283-1284.

Some intervenors in this proceeding expressed concern regarding the Company's competitive solicitation proposal. ABATE and GLREA suggest that the Company could submit unrealistic bids or manipulate the process for its own gain and later raise rates to the detriment of customers. 8 TR 2132; 8 TR 2451-2452. These arguments do not reflect an appropriate understanding of the Company's proposal – as discussed in greater detail below. Moreover, the IRP process provides for cost approval of new supply-side resources in the first three years of Commission approval. If the Company's actual costs exceed the Commission-approved costs, then the Company has the burden of proving that the costs are reasonable and prudent before recovering this additional expense. 8 TR 1283; see also MCL 460.6t(12)(c). Therefore, it would not be in the best interest of the Company to submit "unrealistic" bids.

Under the Company's proposal, prior to conducting a competitive solicitation, the Company would first evaluate EWR measures and energy storage to determine if they can be implemented to offset any projected generation capacity need. However, this would need to be a

cost competitive solution. The Attorney General expressed concern regarding this process. First, Mr. Coppola maintained that EWR measures should not be used if the cost exceeds that of new supply side resources. 8 TR 1286. On this point, Consumers Energy agrees. The Company's proposed structure was to ensure the most cost competitive options available were utilized. Therefore, if the costs of EWR exceed new supply side resources, the Company will pursue the supply-side resources. 8 TR 1284. Mr. Coppola also argued that each competitive solicitation should be opened to all technologies. 8 TR 2386. However, this can add additional administrative costs to the process, and more importantly, could cause unnecessary delays in implementation. The Company's IRP provides the necessary direction to select the types of resources for the competitive solicitation. 8 TR 1284. Therefore, it is reasonable to solicit resources based on the IRP modeling.

(i.) **Annual Project Solicitations**

In preparation of future IRP filings, the Company originally proposed that it would determine if new generation capacity is needed over the next three years and the type(s) of generation that is most reasonable and prudent to procure (e.g., solar, wind, natural gas). 8 TR 1251. Staff witness Harlow argued for conducting annual RFPs. 9 TR 2721. The Company agrees with this recommendation.

As articulated by Mr. Harlow, annual solicitations could provide benefits to customers. This would assure that the most up to date costs are available for IRP modeling and setting avoided cost. It would also help to best align RFP responses with IRP filings to assure that stale cost estimates are not utilized. 9 TR 2721. While the Company agrees that these are benefits, it should be noted that, as discussed further below, a PURPA capacity need demonstration may

restrict the Company's ability to effectively implement the competitive solicitations on an annual basis. 8 TR 1282.

Under an annual solicitation process, for each planning year of solar implementation identified in the IRP, the Company will undertake a competitive solicitation for the quantity of solar build identified in the PCA. For example, for Planning Year 2022, the Company has identified a 300 MW solar competitive solicitation, which would be administered in the beginning of the third quarter of 2019 and would be submitted to the MPSC for approval in the first quarter of 2020. If approved by the end of the second quarter in 2020, the Company would move forward with the selected projects during the third quarter of 2020 through the second quarter of 2022. 8 TR 1281-1282. Exhibit A-106 (KGT-3) depicts how the Company would conduct annual solicitations.

With annual solicitations, the Company recognizes that the contracts entered would need to be approved on a more frequent basis. Thus, the Company agrees with Staff that expedited approval of new PPAs would be appropriate. Based on the solicitation results, the Company will file an application requesting approval of new PPAs, as well as contracts related to Company-owned facilities including build-transfer agreements; development asset acquisition agreements; and engineering, procurement, and construction contracts. 8 TR 1282. Depending on the type of agreement and its intended use, the Company will file the agreement in the appropriate proceeding. To the extent agreements are available, the Company will seek approval within the IRP application. 8 TR 1282.

**(ii.) Implementation Of Competitive Bidding**

The Company's competitive bidding process needs to be implemented in such a way that is fair, reasonable, and in the best interest of customers. Some intervenors raised concerns that

through competitive bidding, the Company would be able to solicit “unrealistic bids” or manipulate the process to select its own bids. 8 TR 2131; 2452. This reflects a misunderstanding of the Company’s proposal. The Company’s competitive bidding proposal is an opportunity for independent power producer and the Company to bid on projects, which are reviewed and evaluated by an independent third party.

For the initial solicitations, due to the complexity of comparing various technologies and costs, the Company proposes utilization of a traditional RFP process. In the future, the Company will evaluate the potential of utilizing reverse auctions as additional experience is obtained with the use of the independent evaluator. 8 TR 1285. Exhibit A-109 (KGT-6) has been created as a visual to clarify the procedure that the Company will use to prepare, issue, evaluate, select, and obtain approval of the projects awarded through each competitive solicitation. The following description provides more detail as to how the competitive solicitation process would work and how the process proposed would prevent any self-dealing by the Company.

The first phase of the Company’s proposed solicitation is the preparation phase. During this phase, the IRP will have predetermined the capacity need and type of technology that will be included in the competitive solicitation. Based on this information, the Company will define which variables of the competitive solicitation. This includes determining what variables will be fixed, such as the energy payments, and which variables of the competitive solicitation will be bid on by the respondents, such as capacity payments. 8 TR 1285.

After these variables are identified, the Company will provide the information to the Independent Evaluator. The Independent Evaluator will review the information and provide feedback. 8 TR 1286. Once finalized, the Company will review the entire competitive solicitation with Staff, including the scope and evaluation criteria, to allow Staff to provide

feedback and any recommended modifications. 8 TR 1287. Once this is finalized, the information will be provided to the Independent Evaluator. Prior to the issuance of the solicitation, MEC and MEIBC contend that the Commission should require the Company to file a RFP with the Commission and provide for stakeholder comment prior to the issuance of the solicitation. 8 TR 1790; 9 TR 2839. However, this extra step is unnecessary and will lengthen the time of the competitive solicitation process. The Company has successfully conducted competitive solicitations in the past and negotiated mutually agreeable contracts with independent power producers to the benefit of customers. Further, projects selected as part of the solicitation will be filed for Commission approval along with a description of the solicitation process. 8 TR 1290. Thus, the Commission's pre-approval of the solicitation is unnecessary.

The next phase in the process is the solicitation phase. The Independent Evaluator is responsible for this phase. At this time, the independent party will publicly issue the competitive solicitation, including all evaluation criteria, to potential respondents. The maximum term length of the PPA should be equivalent to the depreciation schedule of a similar Company-owned asset. Thus, for example, for solar facilities, the Company anticipates soliciting for 25-year PPAs using the competitive solicitation process. 8 TR 1289. The Independent Evaluator is responsible for fielding any questions asked by responding parties. 8 TR 1287. This process is transparent, and all questions and responses will be made public to all Respondents. The Independent Evaluator will collect the submitted proposals and required supporting information from Respondents. The Company will only receive the solicitation materials for the selected projects after the selection has been made and confirmed by the Independent Evaluator. 8 TR 1287. For projects not selected, the Independent Evaluator will hold the solicitation information for a specified period to allow for review by Staff. 8 TR 1287.

The evaluation phase is the next step in the competitive bidding process. The Independent Evaluator is responsible for this phase. During this phase, a short list of recommended projects is developed, and there is no contact between the Independent Evaluator and the Company. 8 TR 1288. The FCM would be applied to the PPA price and the total cost would be what is considered in the evaluation process. 8 TR 1291. While SEIA disagrees with this treatment (8 TR 2009), this is necessary to make a reasonable price comparison. 8 TR 1291. This is because all proposals received in the RFP, including any FCM applicable to the proposals, will be evaluated against the cost of utility build options. 8 TR 1479. Utilization of this process allows the Company to undertake a variety of proposals to determine which option, if any, is the most reasonable and prudent choice for customers. Moreover, SEIA's recommendation to include a clearing price in the evaluation matrix is not feasible. This is because the Company is including value-added criteria in the evaluation matrix and these value-added considerations result in projects being selected based on more than just the cost of the facility. 8 TR 1292. Based on the criteria identified, the list of recommended projects will be ranked from best to worst by the independent party. 8 TR 1288.

Once the Company has received the shortlist of recommended projects from the Independent Evaluator, the Company will undertake the project selection process. Here, the Company will accept the highest-ranking projects and continue down the list, until it reaches a project that it does not want to pursue. 8 TR 1288. Only the information necessary to make the determination will be visible to the Company; this would include the net cost (adjusted by applicable value-added characteristics) of the project and the commodity volumes for each project. 8 TR 1288. The cost of the resource and the value that it provides must be considered to determine the net cost of a resource. This is important when comparing different technologies,

which the Company anticipates will be required since a solar solicitation will be open to any QF technology up to 20 MW in size regardless of the solar technology specified in the competitive solicitation scope. 8 TR 1290. After the selections have been made, the identifying information of the selected projects would be made available to the Company to pursue contract negotiations with the awarded projects. 8 TR 1288. In selecting the appropriate projects, the may select more, or less, capacity than what has been solicited. Any remaining capacity that is available after the selection process is complete will be made available to QFs that were not selected in the competitive solicitation, at the full avoided cost on a first-come, first-served basis. 8 TR 1288. Once the applicable contractual documents have been executed and signed, all selected project information will be submitted to the MPSC for approval.

**b. Implementation Of PURPA**

**(i.) Avoided Cost Methodology**

In the November 21 Order, the Commission approved avoided cost inputs and calculations for energy and capacity. Importantly, in that Order, the Commission instructed Consumers Energy to address PURPA in IRP filings:

“Going forward, the Commission believes that PURPA avoided costs should be integrated with capacity demonstration and IRP proceedings in order to more accurately assess capacity needs. The IRP proceedings are conducive to updating avoided costs, because the Commission will already be evaluating, in detail, utility-specific plans for any incremental generation or purchases along with their associated costs.” November 21 Order, page 33.

As a general matter, GLREA witness Robert Rafson contends that “PURPA contracts will always be cheaper than utility owned assets.” 8 TR 2438. This is simply incorrect. A new solar QF with full avoided cost rates from Case No. U-18090 is expected to result in average costs around \$99/MWh over the contract term. Based on the 2018 renewable energy RFP, the

Company's levelized cost of new Company-owned solar facilities is approximately \$74/MWh as provided in Exhibit EIB-3 (LSS-3). This is less than the approved avoided costs.

Some intervenors in this proceeding argue for the continuation of the avoided cost rates approved previously in Case No. U-18090. GLREA contends that the avoided cost rates approved in Case No. U-18090 are not excessive. 8 TR 2464. Moreover, GLREA maintains that the rates approved in Case No. U-18090 was created by the present conditions and determined through a full cost of service study and should be used throughout the first five-year IRP period. 8 TR 2436. Consumers Energy disagrees with this position. As the Commission previously stated:

“The Commission cannot simply ignore the changes wrought by the passage of time, even though these changes result in making a complex endeavor even more complex for all parties involved. The Commission is hopeful that not every IRP case will require the degree of consideration of PURPA issues that this case requires. But the Commission finds that Section 6t requires a comprehensive, holistic examination of resource planning and costs, and that examination cannot exclude PURPA. Like the Legislature, the Commission also believes that a holistic approach to planning and cost review produces the best result for ratepayers. *See, e.g.*, December 20, 2016 and January 20, 2017 orders in Case No. U-18218.” MPSC Case No. U-20165, October 5, 2018 Order, page 17.

The Company's PCA proposes a dramatic change in the way the Company procures capacity moving forward which takes advantage of declining costs and better aligns capacity procurement with the timing of a capacity need; thus, supporting the need to update avoided costs in this proceeding. With that being said, the Company's proposals, which make up its PCA, do not seek to re-litigate Case No. U-18090 as it applies to existing QFs with PURPA-based PPAs that expire prior to the conclusion of this IRP or the 150 MW that the Commission has required to be purchased from certain QFs at the full avoided cost rate. The

Commission's orders in Case No. U-18090 have indicated that the facilities that fall into these categories should receive compensation based on the Case No. U-18090 avoided cost rates. Therefore, there is a clear demarcation between what the Commission has approved in Case No. U-18090 and what the Company has proposed here.

Despite this demarcation, SEIA maintains that the 1.8 GW of solar projects in the Company's interconnection queue that could be compensated at the avoided cost rate approved in Case No. U-18090. 8 TR 1979. But this is not the case. Simply being in the Company's interconnection queue does not make a generator eligible for a PURPA PPA. A legally enforceable obligation needs to be established before these developers would be eligible for a PURPA PPA. Moreover, under the avoided cost rates approved in Case No. U-18090, this generation would be paid significantly above the market price of capacity and energy, as well as the value of generation recently offered in response to the Company's 2018 renewable energy RFP as discussed below in more detail. 8 TR 1298. The Company's PURPA avoided cost and competitive bidding proposals seek to change the PURPA avoided cost structure so that the Company's PCA may be implemented.

Staff supports the review of the avoided costs and the Commission's avoided cost methodology for Consumers Energy in this proceeding. Mr. Harlow testified that:

“Consumers Energy's current avoided cost is based on a natural gas combined cycle plant with inputs that are now two years old. This was the generating asset that, most likely, would have been built two years ago when the Company's U-18090 avoided cost case was opened. As shown in the Company's current IRP, the only generating asset that the Company plans to build or contract for are solar generating facilities (besides storage technology in the future years). Therefore, it seems reasonable that a methodology of setting the avoided cost based on request for proposals (RFP) for solar generation projects would set an avoided cost for the Company. Staff opines that the avoided cost rate would be based on the highest priced winning bid in each RFP tranche.

This avoided cost would be offered to any qualifying facilities (QF) that are necessary to fill any remaining capacity need not filed by the RFP. Any QF energy and capacity above the needed capacity not filed with RFP responses, would be offered a capacity payment based on the MISO planning resource auction (PRA) and an energy payment...” 9 TR 2720-2721.

Consumers Energy agrees and maintains that avoided costs should be set based on its proposed competitive bidding methodology and the highest cost project selected in the competitive solicitation should establish the full avoided cost rate. 8 TR 1292.

Staff also addressed what the avoided cost rate should be when the Company has no need for additional capacity. Mr. Harlow testified that when the Company does not have a capacity need, QFs should be compensated at the MISO PRA rate and either the MISO LMP or a forecast of LMP prices, at the option of the QF. 9 TR 2721. Consumers Energy agrees – with a five-year or 15-year contract available depending on the energy rate selected by the QF. As the Company presently has no capacity need, avoided cost rates should be set at the PRA rate and either the MISO LMP or a forecast of LMP energy price. The forecast of IRP marginal prices was sponsored by Company witness Clark on Exhibit A-8 (TPC-6), page 2. As the Company is not in need of capacity, it is reasonable to compensate QFs at these rates. 7 TR 1294.

IPPC suggests that the rates approved in Case No. U-18090 are lower than the Company’s avoided costs (9 TR 2877-2879); nevertheless, IPPC argues that as it was an active litigant in Case No. U-18090, the determination from that proceeding should apply to its members. 9 TR 2879. While Consumers Energy agrees that the avoided costs approved in Case No. U-18090 applies to new PURPA contracts that are executed with the Company and QFs at present (8 TR 1296), this does not continue in future years. When the Company enters into future PURPA contracts with QFs, it will use the most recently Commission-approved avoided cost rates. 8 TR 1296. Moreover, IPPC maintains that a natural gas fired generation plant

should be used as a proxy unit for setting avoided costs because the RE Plan transfer costs are based on a natural gas fired generation plant. 9 TR 2878. However, as recognized in the Commission's Orders in Case No. U-18090, the transfer price mechanism that IPPC witness William Stockhausen is referring to is a simplified methodology used to allocate costs between the RE Plan and the PSCR expense to simplify the cost allocation process. 8 TR 1297. This methodology was established prior to the development of the IRP and the PCA where the Company has taken the position that it proposes to build solar facilities as the next generating unit.

While IPPC alleges that there are inconsistencies between the Company's proposed avoided cost methodology and the avoided cost methodology in Case No. U-18090 (9 TR 2878), this is an inaccurate. IPPC bases this argument based on Company witness Troyer's discussion of the costs related to Apple Blossom Wind Farm, Cross Winds Energy Park II, and Cross Winds Energy Park III. This dismisses the reason why Mr. Troyer discusses these projects. The cost of the wind farms was to provide as an example as to how the Company's actual avoided costs are not consistent with the avoided costs approved in Case No. U-18090. These units were utilized in the comparison because they were the most recent renewable energy projects approved by the Commission. 8 TR 1295. More importantly, contrary to IPPC witness Stockhausen's assertion (9 TR 2880), the three wind project's costs represented are the full costs of the projects. The levelized price represents the projected levelized cost of each of the facilities through the duration of the PPA or expected life of the facility. The levelized cost includes the full costs of the facility including costs of on-going operation and maintenance expense, capital costs to construct and operate, depreciation, property taxes, landowner payments, PTCs, financing, return on equity, etc. over the life of the facility. The levelized cost represents the cost of the facility.

The Company proposes a competitive bidding process to determine avoided costs. This provides the most accurate representation of the costs that the Company actually avoids by purchasing from a QF, provides an orderly process for the acquisition of capacity, and provides customers with the benefit of competitively priced energy and capacity.

**(ii.) Full Avoided Cost Eligibility**

Under the Company's avoided cost proposal, QFs are able to contract with the Company to fill any remaining capacity available that was left unfilled by the competitive solicitation. Staff witness Harlow testified that under the Company's avoided cost proposal, Staff recommends that "[t]he QFs would receive a contract with terms substantially similar to the RFP respondents. Any QF capacity above this amount would be offered PRA pricing for capacity and an energy payment based on 1 of 2 options at the QFs discretion. The first option would be to offer the QF energy pricing based on the MISO locational marginal pricing (LMP) at the time of delivery. The second option would be to provide a schedule of projected energy based on the IRP resulting marginal energy price." 9 TR 2721. The Company agrees with this recommendation.

Additionally, under the Company's proposal, there are other methods in which a QF could pursue a PURPA contract with Consumers Energy. Company witness Troyer testified:

"1. Any QF up to 20 MW in size will be eligible to participate in the Company's competitive solicitations, regardless of the technology specified, and receive the rate included in their proposal, if selected;

"2. Any remaining capacity solicited that is not filled through the competitive solicitation will be made available to QFs up to 20 MW in size on a first-come, first-served basis at the full avoided cost rates based on that solicitation;

“3. Any QF with an expiring PURPA contract for energy and capacity will be eligible to receive the most recently Commission-approved full avoided cost rates; and

“4. QFs up to 150 kW that request the Standard Offer contract will receive the most recently Commission-approved full avoided cost rates.” 8 TR 1302.

**(iii.) Contract Terms**

Staff and GLREA raised some concern with the contract terms offered to participants in Company’s competitive solicitations compared to the contract terms offered to QFs who are offered contracts at full avoided costs. 9 TR 2721; 8 TR 2462. The Company agrees that to use the competitive solicitation, as the basis for avoided costs, the PPAs provided to QFs under PURPA should be materially the same as the PPAs provided to the solicitation. 8 TR 1303. The Company would seek to provide similar terms to similar facilities. 8 TR 1303. This is reasonable because it will ensure that the different projects are comparable to each other.

**(iv.) Standard Offer**

The Company proposes to reduce the size of projects eligible for the Standard Offer Tariff from 2 MW to 150 kW. 8 TR 1274. In reducing the size of projects eligible for the Standard Offer Tariff to 150 kW, the Company proposes offering program participants the full avoided capacity and energy rates regardless of the Company’s capacity need. 8 TR 1275. As previously explained, the Standard Offer Tariff is most appropriate for small developers and customers that lack the experience and resources needed for larger forays into the electricity generation business. 8 TR 1274.

Staff witness Harlow agreed with the Company’s proposal to lower the Standard Offer tariff. Mr. Harlow argued that this would likely reduce the complexity related to interconnection, and as a result, would lower interconnection costs. 9 TR 2722. The Company

agrees. The interconnection cost and complexity of interconnection is specific to the facility and the point of interconnection on the electric distribution system. By reducing the size of a generator, this in turn decreases the likelihood of significant interconnection costs. 8 TR 1303. Some parties to this proceeding disagreed with the proposed reduction in the Standard Offer tariff size. While arguing that the Standard Offer could continue to be for projects up to 2 MW, or even increase in size to 3 MW, these parties fail to recognize that the Company is offering to compensate standard offer projects at full avoided costs regardless of need. This would not be possible if the Standard Offer was set at a higher amount. In its proposal, the Company is attempting to make it easier for small projects by keeping a more stable avoided cost rate that would not change with the Company's capacity need. The same treatment is not necessary for larger projects.

(v.) **Capacity Determination**

In its November 21, 2017 Order in Case No. U-18090, the MPSC established a 10-year outlook for determining if there is a capacity need and established that a Commission order is the necessary mechanism to declare whether the Company has a capacity need. The utilization of a 10-year capacity demonstration is greatly impacted by the Company's competitive bidding proposal. The PCA contemplates that capacity "need" determinations will be made on a much shorter basis, and one of the biggest advantages of the PCA is the incremental nature of adding solar generation to the system. 8 TR 1470. This allows the Company to not construct a large baseload plant.

As explained by Company witness Troyer, there are currently over 1.2 GWs of QF projects interested in selling capacity to the Company at the current avoided cost. 8 TR 1249. This equals an added cost to customers of approximately \$175.6 million annually at an average

cost of \$99.69/MWh over a 20-year contract length. 8 TR 1249. The continued utilization of a 10-year capacity sufficiency outlook in years beyond the three for which the Company plans to run a competitive bid and present in an IRP, the Company would be required to purchase from those QFs once a legally enforceable obligation is created with the Company. 8 TR 1249. This negates the PCA's planned advantage of leveraging decreasing technology costs and attempting to match supply and demand on a closer-term basis and prevents the Company from filling its capacity needs on an incremental basis.<sup>26</sup> 8 TR 1471.

As part of this proceeding, the Company originally proposed a three-year capacity determination window, however, in recognition of arguments made by Staff and some of the intervenors, the Company recognizes that there are conflicts between its proposal to use a three-year window and the State Reliability Mechanism ("SRM") four-year planning horizon. 8 TR 1304. Therefore, the Company agrees with the proposed utilization of a 5-year capacity demonstration period.

While a five-year capacity demonstration period may be acceptable, there may be potential issues with the implementation of the Company's PCA. For example, if a five-year demonstration shows a capacity need and PURPA QFs were able to claim the entire capacity amount, there would not be a competitive solicitation to reset the avoided costs. 8 TR 1304. This issue can be resolved if the Commission determined the Company's capacity need based on the Company's approved IRP and implementation of the IRP through competitive solicitations.

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<sup>26</sup> IPPC argues that as an active litigant in Case No. U-18090, the determinations made with respect to the Company's 10-year capacity demonstration window applies to their members. 9 TR 2879. However, there is no evidence to support this claim and it would be administratively burdensome to have different capacity determination windows for different generators. The most recent capacity process approved by the Commission is the process that should be used for all providers – unless changed by the Commission in a future case.

See Exhibit A-110 (KGT-7). The proposed process is similar to the manner in which the RE Plan is implemented. Exhibit A-106 (KGT-3) provides an example of how this would work.

Staff witness Harlow addressed the above issues related to five-year capacity need determination period in discovery question 20165-CE-ST-25, provided as Exhibit A-110 (KGT-7), and clarified Staff's position regarding how the determination period would be implemented as follows:

“If the Company is actively pursuing its Commission approved capacity plan as presented in its Integrated Resource Plan, then Staff believes that the Company does not have a capacity need, provided the Company will be conducting competitive solicitations, allowing all qualifying facilities (QF) to participate regardless of technology. If the Company were to have remaining capacity, not filled through a competitive solicitation in a particular tranche, then this capacity should be offered to QFs at the highest winning bid price, until such time that the requested capacity through the competitive solicitation is filled.”

The Company agrees with Mr. Harlow and proposes that if the Company is pursuing a Commission-approved capacity plan, such as the PCA presented in this IRP, the Company should be found to not have a capacity need over the capacity forecast period. 7 TR 964.

Various intervenors in this proceeding disagree with the Company's proposed capacity determination period arguing that it would result in the Company never having to capacity need. This is incorrect. To start, on behalf of ELPC, Mr. Jester proposes that capacity needs be should be determined by looking to see if there are any future capacity additions that can be deferred or avoided. He maintains that a good dividing line for deferring a future capacity addition is whether the Commission has approved cost recovery for future capacity additions. 8 TR 2257-2258. This suggestion is inappropriate as it would likely result in most of the Company's future capacity plan always being characterized as a need and subject to fulfillment by QFs. 8 TR 1483. This is especially true if the 10-year capacity demonstration period is

maintained. Beyond the near term, the Company is unable to obtain cost recovery approval for any portion of its capacity plan. The IRP only permits approval of cost recovery for capacity additions over a three-year period. The same is also true for the statutory Certificate of Necessity process. 8 TR 1483. While Mr. Jester contends that his proposal would allow for a ramp-up schedule based on the results of the examination of the IRP (8 TR 2257), based on the limited window for cost approval, the Company would be denied the relief envisioned.

ELPC/MEC witness Jester also contended that the four-year capacity demonstration, related to SRM requirements, results in the Company never having a capacity need. 9 TR 2254. The Company's agreed to adoption of a five-year outlook should satisfy his concerns. 8 TR 1307. Additionally, Mr. Jester argues that there is "no logical basis to value energy differently for a QF that meets a present capacity need from a QF that does not meet a present capacity need." 8 TR 2261. However, the Company's RFP results disprove this contention. In its 2018 RFP, the Company received proposals in its 2018 RFP with bundled rate pricing that was less than the Company's solar weighted LMP forecast. 8 TR 1307. This means that the cost for energy and capacity is less than the "value" of energy. Thus, if the Company provides a LMP energy forecast as the energy component of a competitive solicitation, the revenue received by the selected proposals will exceed the revenue required for their project. As Company witness Troyer explained, "To get the most economic projects in the competitive solicitation, the Company will need to specify an energy rate that is less than the long-term LMP forecast. The Company's proposal addresses this issue by offering QFs the full energy price over a shorter-term contract." 8 TR 1307.

SEIA also argues that the Company's proposal allows for the Company to construct a definition of capacity need that would result in a capacity need never being triggered.

8 TR 2024. This fails to recognize that under the Company's proposal QFs up to 20 MW in size, of any technology, are eligible to participate in each of the competitive solicitations. 8 TR 1305-1306. Therefore, QFs up to 20 MW in size are eligible to claim all of the Company's future capacity through the competitive solicitation.

GLREA additionally contended that the determination of a capacity need should be at the discretion of the Commission. 8 TR 2461. The Company agrees with this point. The Commission has the authority to establish and implement avoided cost rates and establish a capacity demonstration process. In Case No. U-18090, the Commission approved a capacity demonstration filing process for resetting avoided cost rates and suggested that this IRP filing be used to determine future capacity needs. In this proceeding, consistent with the Commission's previous guidance, the Company is proposing the use of a 5-year capacity determination. Approval of this request is reasonable and at the discretion of the Commission.

**c. Blended Avoided Cost Rate**

At 9 TR 2917, SEIA witness Lucas argues that the determination of the blended PURPA Avoided Cost rate, proposed as an alternative to the competitive solicitation avoided cost methodology, does not properly reflect the blended cost of these resources. GLREA witness Rafson further argues that a blended rate based on demand-side resource is inappropriate because it does not scale and is not available to third parties. 8 TR 2436. These criticisms of the Company's alternative blended avoided cost rate should be rejected.

In taking issue with the Company's alternative blended avoided cost rate, Mr. Lucas proposes an avoided cost methodology which requires independent developments of avoided cost for each technology included in the blended rate. The problem with this approach is that it is overly complex and with more resources included in the blended calculation, as would be the

case when the Company begins to fully implement the PCA, the calculation increases in complexity. 7 TR 967-968. Mr. Clark also explained that the improved accuracy allegedly provided by Mr. Lucas' calculation could be taken to extremes. 7 TR 968. This is because each energy efficiency program and DR program relies on different assumptions and carry a different life. Under Mr. Lucas' method, it would be increasingly difficult to determine at what point is it appropriate to aggregate and at what point should the individual avoided cost be considered. 7 TR 968.

Finally, Mr. Clark explained that the methodology used by Mr. Lucas introduces additional uncertainty as it requires the projection of energy prices well beyond the planning period. Specifically, Mr. Lucas' method required the projection of energy prices 17 years beyond the planning period. 7 TR 968. While the Company also projected energy prices beyond the planning period in developing its proposal, the Company's projections were only five years beyond the planning period. 7 TR 968.

With respect to Mr. Rafson's criticisms, the Company agrees that demand-side resources require some significant time to ramp to meaningful levels and are primarily only available to LSEs. However, the Company disagrees with the conclusion that these resources should not be used to set avoided costs. 7 TR 968. These resources are the appropriate costs to use to determine the PURPA Avoided Cost rate because they represent the capacity and energy resources that would be avoided by the utility if purchases were made from a QF instead. 7 TR 968.

#### **d. Distributed Generation Carve Out**

Staff proposes modification of the competitive bidding process to incorporate additional amounts of customer distributed generation. 9 TR 2568. Staff witness Meredith A. Hadala

proposes that 2% of the capacity planned to be acquired in every competitive solicitation be reserved for a Customer Distributed Generation program. 9 TR 2728. Under this proposal, the program size would be based on 2% of future competitive solicitations where eligible projects would be located at a customer site and limited in size to 550 kWac. Initially, the price under the program would be set at the avoided cost established in the most recent competitive solicitation, and if there was not sufficient interest in the program, a reverse auction would be used to allocate the capacity up to a maximum amount limited to 150% of the avoided cost. 9 TR 2731. Any unfilled program capacity would be rolled into a future competitive solicitation, and the contracts would be structured as buy-all, sell-all and will have a term of up to 20 years. 9 TR 2731.

While recognizing that customer-owned distributed generation resources are, and will continue to be, a part of the Company's electric system, Consumers Energy believes that the addition of a Customer Distributed Generation program is premature and requires further research and consideration. Currently, the Commission has not approved a distributed generation program for the Company as required by Act 341 and Act 342. In fact, the Company has yet to propose a new distributed generation tariff part of any electric rate case it files after June 1, 2018, as required under the provisions of Act 341, Section 6a(14) and the Commission in its April 18, 2018 Order in Case No. U-18383. 8 TR 1719. This proposal would be made in the Company's next electric rate case. While Staff seems to contend that the Customer Distributed Generation Program would be a second separate distributed generation program from the mandated Distributed Generation Program in Act 341 and Act 342 (Exhibit A-123 (TEH-9)), it is unclear why a second separate distributed generation program should be put into place prior to the program mandated by Act 341 and Act 342. The Company is concerned about how the proposed Customer Distributed Generation Program would cost-effectively contribute to the

capacity requirements necessary to meet the Company's load requirements. This is especially true given that under Act 342 participating generators in the distributed generation program are limited to 150 kW or below, and have an established capacity of 1% of the Company's average in-state peak load for the preceding five calendar years, and cannot exceed the customers' annual energy requirements.<sup>27</sup> 8 TR 1719.

In looking at the structure of Staff's proposed Customer Distributed Generation program, there are areas of the proposed program that cause the Company concern. First, under the proposed Customer Distributed Generation program, generators up to 550 kWac are eligible to participate. This seems to be contrary to the statute. MCL 460.1173 specifies that the limit for the size of generators that customers are eligible to participate in the distributed generation program is 150 kW. By raising the eligible system size for all generators to 550 kW for the proposed Customer Distributed Generation, the proposed increases the system size for distributed generation resources beyond the statutory limits. 8 TR 1720. In order to approve this program, the Company contends that the size of the generator in a distributed generation program must be limited to 150 kWac and any capacity generated would be required to contribute to the distributed generation cap.

Second, the Company questions the compensation methodology proposed for eligible generators. Under the Company's Standard Offer proposal, discussed above, Consumers Energy is proposing to offer full avoided costs to proposed to offer customers with system sizes 150 kW or less, which takes into account that small developers and individual customers may lack the experience and resources needed for larger forays into the electricity generation business. 8 TR

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<sup>27</sup> While Staff contends that participants in this program would not be counted towards the 1% cap (Exhibit A-124 (TEH-10)), it is unclear how this would comport with the statutory distributed generation program cap requirements. See MCL 460.1173.

1723. Staff proposes offering the same generators the opportunity to be paid as a 150% of the avoided cost rate to fill the capacity set aside for the program. The basis for the 150% of the avoided cost rate is unclear and unsupported. While Staff witness Hadala contends that capping the cost at 150% of the avoided cost rate would keep costs from being too high. It is currently unknown what the avoided cost rate would be as the Company has not undertaken a competitive solicitation. 8 TR 1723. Further, if there is a lack of demand for the Customer Distributed Generation Program at avoided cost rates, it seems as if the program would simply close to further participation versus increasing costs for all customers. 8 TR 1723. Additionally, the buy all/sell all methodology proposed by Staff (9 TR 2730) is not consistent with Staff's recommended compensation methodology for distributed generation under Act 342 and is not consistent with the inflow/outflow methodology for distributed generation as proposed in "[t]he Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff" issued February 21, 2018.

Third, the Staff's proposed program has implications on the Company's capacity position in a given planning year. Under Staff's proposal, if the capacity reserved is not fully subscribed at the end of the reverse auction, the capacity amount would be "rolled over" and added to the reservation amount during the Company's next competitive solicitation for capacity. Exhibit A-121 (TEH-7). If there is a capacity gap for the Company after the reservation amount is not fully subscribed in a given solicitation, Staff expects that the Company consider "other methods to fill this capacity" such as EWR, DR, and PURPA contracts. Exhibit A-121 (TEH-7). Based on this recommendation, the implications to the Company's capacity position in a given planning year are unclear if the Company is determined to be short required capacity. 8 TR 1723. Since there would be no way to predict if a given reservation would be fulfilled, any

capacity that is reserved for the Customer Distributed Generation Program that remains unsubscribed should not impact the Company's ability to meet its capacity obligation. 8 TR 1724. The full amount of the reservation should be treated as the Company meeting its capacity obligation in a given year.

Creation of a Customer Distributed Generation Program is unreasonable at this time. Currently, the costs to customers for implementing and administering a Customer Distributed Generation Program are unknown, and a cost study should be performed prior to implementing or approving any new distributed generation program. 8 TR 1721. Further research and development should occur before the program is approved. Customer demand or interest in the proposed program is unknown. Staff's 2% capacity reservation chosen for the program appears arbitrarily determined as there is insufficient customer research to support the choice of 2%. See Exhibit S-10. Staff provided no information as to which, or how many, customers have discussed this topic with Staff, or what size of systems were discussed. To introduce a new customer program without sufficient supporting customer research is premature, further research should be completed prior to moving forward. 8 TR 1724. Prior to adopting this program, the Company believes that a collaborative discussion between interested stakeholders should be held to discuss customer interest and design opportunities. 8 TR 1725. Customer research should be reviewed to better define customer preferences for distributed generation program. Better definition of purpose, process, and standards will enable better definitions of costs and therefore enable equitable compensation pricing for distributed generation systems. 8 TR 1726. Additionally, a new distributed generation tariff will be considered in the Company's next electric rate as discussed earlier in this testimony. Therefore, approval of Staff's proposed Customer Distributed Generation program is premature.

## 8. FCM

Several parties in this case sponsored witnesses who took issue with various aspects of the Company's requested FCM. Witnesses for Staff, the Attorney General, ABATE, MEC, SEIA, ELPC, GLREA, and RCG all criticized aspects of the Company's FCM proposal. In general, the parties criticize the rationale and efficacy of the Company's proposed imputed debt methodology for calculating the FCM and argue that the FCM should be reduced in a variety of ways or denied altogether.

Irrespective of the parties' differing approaches to this issue, Company witness Maddipati noted, that "the core of the criticism involves the role played by a public utility in the procurement of safe, reliable, and affordable energy." 7 TR 735. The testimony offered by Mr. Torrey in support of the Company's proposed FCM recognizes that regulatory outcomes in this IRP – like all regulatory outcomes – need to reflect an appropriate balance between the interests of the Company and customers. Mr. Torrey explained:

"[T]he Company is proposing to procure its capacity through a competitive-bid process conducted by an independent third party that will allow all interested parties to participate. This strategy – which works to leverage the PCA's clean, lean, and modular characteristics – is the right strategy to take to result in lower costs for customers. But a competitive bid methodology presents significant risks to the Company's ability to attract capital investment for needed infrastructure investments and provide sustainable returns to investors unless there is an incentive for the Company to enter into PPAs. Otherwise, the Company's credit ratings could become stressed and the Company would have a bias towards constructing its own projects to own, or entering into 'build-transfer' agreements for the ownership of projects, whereby a developer builds the project and then sells it to Consumers Energy." 8 TR 1474.

That balance is not achieved where the incentive for investors to put their money into the utility is inadequate or no longer exists. Customers benefit from investors' capital and investors benefit from the earnings that, in the traditional utility model, are tied to owned assets.

While some of the witnesses for other parties ostensibly acknowledge the fact that public utilities, such as Consumers Energy, rely on private capital to operate, and have a need to produce earnings in order to continue attracting that needed capital, the witnesses arguments against the Company's proposed FCM nevertheless fail to give adequate regard to developing an FCM that will actually achieve that goal.

Mr. Maddipati testified:

“[T]he FCM accomplishes two purposes: (i) it incentivizes the policy objectives outlined by Mr. Torrey and (ii) it fairly incorporates for the financial impacts outlined in my direct testimony. Even if the Commission were to be persuaded (which I do not believe it should) that there were no policy rationale for an FCM, the financial impact of the FCM would remain. The reverse would also be true. Even if the Commission were to be persuaded that there was no financial impact (which I do not believe it should), then the policy objectives outlined by Mr. Torrey would still remain.” 7 TR 735.

The fundamental flaw running throughout all of the parties' criticisms and counterproposals with respect to the FCM is their failure to ensure that their proposals would result in a sufficient FCM to achieve both of those purposes. The Company urges the Commission to keep that issue in mind as it considers the arguments of the other parties. The Company's explanation for the rationale supporting the need, application, and calculation of the FCM is set forth in Section III.E. of this Initial Brief.

Notwithstanding the claims of other parties, the Commission should adopt the FCM proposed by Consumers Energy for the reasons stated above. If the Commission decides not to adopt the Company's proposed FCM, the Company would agree to Staff's proposal to allow the Company to own up to 50% of its generation resources and allow for competitive bidding on the remainder with an FCM based on the Company's pre-tax WACC using its permanent capital structure, as proposed by MEC. 7 TR 758-759.

The Company provides further response to particular claims made by the other parties below. Because several parties raise similar issues, the Company's response focuses in many places on its response to Staff's arguments or other parties who provided the most detailed arguments on the issue. Failure to explicitly mention the arguments of a particular witness should not be construed to represent agreement with the witness's similar or related arguments.

**a. Response To Staff's And Other Parties' Arguments Regarding The Need For An FCM To Address Imputed Debt**

Several of the parties who took issue with the Company's FCM did so on the basis that the FCM is not actually needed in order to address imputed debt. Witnesses for Staff, the Attorney General, MEC, and SEIA all dispute whether the Company's imputed debt methodology sufficiently justified the need for an FCM. The Company notes that it appears that Staff is generally supportive of an FCM to incent the Company to enter PPAs. 7 TR 739. Staff's criticisms appear only to relate to the legitimacy of the imputed debt methodology for establishing the appropriate level of the FCM. 7 TR 739. In other words, Staff (and MEC, the Attorney General, and SEIA) argue that, to the extent imputed debt is a problem, it should be addressed through general rate cases, but not be addressed through the FCM.

Mr. Maddipati addressed Staff's position in his rebuttal testimony. Mr. Maddipati testified:

"Staff's suggesting that the Company change its business model and deal with the impacts later is simply not a prudent course of action.

"Staff is not suggesting that PPAs have no financial impact. In fact, Staff witness Nichols goes on to validate that several states incorporate the impact of imputed debt by increasing the equity ratio of the respective utilities. This increase in equity ratio as a result of imputed debt has an impact on costs to utility customers. While Staff agrees that any FCM should be incorporated in any 'buy versus build' decisions, Staff is proposing the Commission not evaluate the potential costs associated with imputed debt. Staff's proposal could result in the Company entering PPAs that on the surface may appear cheaper than a potential build scenario, but

would ultimately result in higher costs in the future. Unless 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." 7 TR 740.

If the imputed debt impact of a proposed PPA – which Staff and other parties acknowledge to be real – is not incorporated into the costs considered at the time the procurement decision is made, then there is no assurance that option chosen is really the lowest cost option. Without an FCM based on imputed costs, either customers lose some of the value of competitive bidding or the Company is left short of recovering the real costs caused by the PPA.

Staff's position that it would be more appropriate to address imputed debt issues in a general rate case appears to be motivated, at least in part, by the perception that the Commission has already opined on the issue. Staff witness Proudfoot cited a Commission Order in Case No. U-15806 in which the Commission determined that imputed debt associated with PPAs under DTE Energy Electric Company's RE Plan were best addressed in the Company's general rate case. 9 TR 2559-2560. However, the Commission's decision in that case was made prior to passage of Act 341, which includes language specifically authorizing the Commission to consider an incentive for a utility entering a PPA. MCL 460.6t(15). Furthermore, Mr. Maddipati testified that the scale and scope of the Company's PCA is far different than the RE Plan in Case No. U-15806. 7 TR 739. Mr. Maddipati explained:

“Case No. U-15806 dealt with a small portion of DTE's capacity related to a legislatively mandated renewable energy requirement which resulted in 200 megawatts of purchased power. The Company's PCA, however, is neither mandated nor narrow. In this case, the Company is proposing to voluntarily change the way in which it procures its capacity and could result in thousands of megawatts of PPAs.” 7 TR 739-740

Case No. U-15806 did not deal with a proposal that would fundamentally transform the traditional regulatory model for how utilities earn a return on their invested capital. This case does.

Several parties argued that the fact that Consumers Energy currently has PPAs totaling up to approximately 3 GWs of capacity with no FCM provides further evidence that no FCM is necessary to address imputed debt issues. Mr. Maddipati notes, however, that these arguments fail to recognize two important facts:

“(i) Two of the largest PPAs, the Palisades Nuclear Plant and Midland Cogeneration Venture Limited Partnership (‘MCV’) facility are set to expire in 2022 and 2025, respectively. These two PPA represent over 2 GWs and are set to expire in 4-years and 7-years, so in effect the Company’s current PPAs are relatively short in duration. If Mr. Nichols is suggesting the Company enter PPAs of less than 10-years, then his argument may carry some weight, but the Company’s PCA could see it potentially enter into 6,000 MWs of PPAs with lengths of up to 25 years; and

“(ii) The Company is proposing to competitively bid all of its future generation – the Company currently owns ~70% of its generation and the PCA combined with competitive bidding could cause that to be reduced dramatically.” 7 TR 742-743

Mr. Maddipati explained that equating the Company’s current PPAs with its potential future supply mix under the PCA proposed in this case is misleading. 7 TR 743. Again, the scope and scale of the Company’s potential reliance on PPAs under the proposed PCA in this case is not comparable to any PPA portfolio that currently exists in Michigan.

Staff witness Harlow also attempted to demonstrate that the imputed debt impact on Consumers Energy associated with future PPAs would not actually be a significant impact. However, Mr. Harlow’s calculation contained a significant error that renders his conclusion incorrect. In an attempt to recreate S&P’s imputed debt methodology to show that Consumers Energy would still maintain a 50% equity ratio even after accounting for imputed debt from new

PPAs, Mr. Harlow incorrectly used a single-year payment, rather than the net present value of all the PPA payments, in his calculation. Mr. Maddipati sponsored Exhibit A-113 (SM-4), which reproduces Staff's analysis but corrects for this error. Exhibit A-113 (SM-4) shows an equity ratio for a 10-year PPA and 20-year PPA which results in equity ratios of 47% and 44.75%. Mr. Maddipati testified that these are 550 to 775 basis points below the currently authorized equity ratio and far from a 50-50 equity to debt ratio as Staff concluded. 7 TR 743.

Finally, Staff appears to believe that its proposal to allow the Company to own up to 50% of any new generating assets under the IRP would also render the need to use an imputed debt methodology for calculating the FCM unnecessary. Once again, however, this claim does not adequately account for the scope and scale of potential PPA procurement under the IRP.

Mr. Maddipati testified:

“I agree with Mr. Proudfoot's statement on page 32 of his direct testimony that there are benefits to the Company owning its own generation resources:

“‘Allowing the Company to own a portion of the new resources will also provide the Company with greater control over the maintenance and operation of the equipment, greater insight into the performance of the equipment, and better equip the utility to forecast the output from the solar resources.’

“However, Mr. Proudfoot's cap of 50% is ~25% lower than the generation the Company currently owns today. While I agree with Mr. Proudfoot that there are benefits if the Company ultimately owns some portion of its new solar resources, I would not agree that his proposal alleviates the need for an FCM on the resources it does not own. Shifting the Company's owned generation from nearly 70% to 50% over time would still be a dramatic shift.”  
7 TR 753.

Mr. Torrey acknowledged that Company ownership of up to 50% of the new renewable resources included in the PCA would lessen the Company's concern over moving away from the

traditional business model. 8 TR 1489. However, he explained that the Company is not willing to abandon the tradition regulatory model for such a significant portion of its business. 8 TR 1489. According to Mr. Torrey, the FCM incentive proposed by the Company – which is designed to address the imputed debt impacts of PPAs – should still apply to the PPAs not owned by the Company. 8 TR 1489.

In addition to the arguments discussed above, the Company notes specifically that SEIA witness Kevin M. Lucas appears to take the position that the FCM should not be based on an imputed debt methodology because imputed debt is simply not a valid concern for Consumers Energy at all. This is a more extensive claim than the arguments made by other parties relative to the need for addressing imputed debt in the FCM. Mr. Lucas claims that the concerns expressed by the Company regarding the impact of imputed debt on the Company’s credit metrics and ability to attract capital are “hypothetical at best.” 8 TR 1994.

In his rebuttal testimony, Mr. Maddipati responded to Mr. Lucas’ arguments as follows:

“Mr. Lucas’ criticism of the Company’s position appears to be that I did not confirm that there is a bright-line test for which a rating agency would potentially downgrade a utility based on imputed debt from PPAs. Managing the credit and financial health of any company is a complex process, and the analysis conducted by credit analysts and rating agencies is equally nuanced. In my experience, decisions regarding the credit of any company are rarely made solely on a single issue but involve the interplay between numerous factors. That there is a financial impact from the long-term obligations created by PPAs should hardly be controversial – if there was no impact, as Mr. Lucas seems to imply, why would any criteria or consideration be published by any credit rating agency? Furthermore, Mr. Lucas makes the same erroneous assumption made by Mr. Nichols that, since the Company currently has PPAs with no FCM, an FCM is not needed in the future.

“The risks posed by off-balance sheet financing are hardly novel, but Mr. Lucas seems to suggest ignoring the impact until a company is on the precipice of a downgrade or completely unable to access capital. Managing the credit of any company, let alone a

public utility, in such a manner would not be prudent. The Commission should note several other witnesses in this case concede that PPAs impact the financial profile of the utility, though they debate the magnitude of such an impact and whether this case is the appropriate venue to address the impact, which I believe it is. Mr. Lucas was asked if he has ever had experience managing the credit of a utility or financing of any public company. He responded that he has not. The Commission should give little weight to Mr. Lucas' non-expert conjecture regarding such a complex and nuanced topic." 7 TR 754-755.

Although several other parties argued that the impact of imputed debt would be better addressed through means other than the FCM, only SEIA's witness – who has no financial expertise or experience – claimed that imputed is just not a legitimate issue at all. In fact, as Mr. Maddipati noted, witnesses for Staff, MEC, and ABATE all expressly acknowledge that PPAs have a real financial impact on utilities. 8 TR 1795, 2137; 9 TR 2715. The Commission should reject Mr. Lucas' arguments as being without any credible foundation.

Contrary to the arguments of the parties, there is no better or indirect way to address the imputed debt impacts of a PPA portfolio of the potential scope and scale that could occur under the Company's proposed IRP than to utilize an imputed debt methodology directly. The Commission should approve the Company's request for an FCM based on the Company's proposed imputed debt methodology.

**b. Response To Various Parties' Claims That An FCM Is Not Needed Because The PSCR Mechanism Guarantees Cost Recovery**

Witnesses for several parties also claim that the Company does not need an FCM because cost recover for PPAs are essentially guaranteed as part of the PSCR process. Several witnesses take the position that the guarantee of recovery under the PSCR process eliminates the need to address imputed debt.

As an initial matter, these claims overlook or deny the basic problem that, under traditional utility regulation, utilities' earnings are dependent on owning utility assets and the

PCA has the potential to dramatically decrease or even eliminate Consumers Energy's ownership of generating assets. Therefore, even if it were accurate that the PSCR process addresses one of the objectives for implementing the Company's proposed FCM in this case (which it does not), an adequate FCM is still needed to address the Company's concerns regarding the incentives and disincentives built into the traditional regulatory model.

Furthermore, Mr. Maddipati explains that there is no merit to the contention that the PSCR process eliminates the need to address imputed debt through the FCM. Mr. Maddipati testified:

“PPAs are a direct obligation of the Company, not customers. The same is true for the Company's first mortgage bonds (debt) and equity – these are not direct obligations of the customers but the Company. The Commission authorizes revenue through general rates that are ideally sufficient to cover operating expenses, service debt, and allow its owners to earn its authorized ROE. To the extent rates are insufficient, the Company's debt would be serviced first and any remaining revenues would flow to equity holders. The same is true of PPAs – while the Company expects to collect revenue sufficient to recover PPA costs through its PSCR mechanism, if insufficient revenue were collected, PPA payments would in fact still be made. This fact should hardly be surprising, PPAs are routinely entered by businesses that are not utilities and clearly don't have PSCR mechanisms – the risk for a PPA provider is that of its counterparty, whether it be a utility or some other business. While the customers of any company ultimately provide the revenue used to pay expenses, it's ultimately the company which entered the contract that bears the legal obligation.”  
7 TR 736.

Mr. Maddipati points out that the Company's PSCR mechanism is simply the vehicle through which revenues are collected. 7 TR 737. It is true that the PSCR mechanism allows for more timely revenue recovery relative to general rates and a true-up mechanism. 7 TR 737. However, Mr. Maddipati explains that this features of the PSCR is why S&P uses a risk factor of 25% when determining the financial impact of PPAs. 7 TR 737. In other words, the PSCR process is

already incorporated into S&P's determination of the appropriate amount of imputed debt to include in its evaluation of the Company's credit rating.

**c. Response To Parties' Claims Regarding The Appropriate Method For Calculating The FCM**

Witnesses for Staff, MEC, and SEIA all included arguments in their testimony that criticized aspects of how Consumers Energy calculated the FCM proposed in this case. For the reasons discussed below, each of these parties' criticisms should be rejected.

First, Staff claimed that the Company's method of calculating the FCM is incorrect because the Company includes the entire PPA cost in the calculation, rather than only the capacity component of the PPA. SEIA also makes a similar argument. Company witness Maddipati responded that these arguments misrepresent the Company's proposal. 7 TR 749. In discovery and again in his rebuttal testimony, Mr. Maddipati clarified the Company's position. He explained:

“PPAs create fixed payment obligations for a utility, and my proposed methodology would only include payments that were contractually obligated. For example, if a PPA included the option to purchase the energy based on economic dispatch, but not the requirement to do so, then expected payments for the energy option would not be included. This is similar to the Company's current MCV contract – the Company would only propose including the fixed payments (both energy and capacity) required under this contract in calculating the FCM. The variable payments to MCV are at the control of the Company and only made to the extent the plant is dispatched on an economic basis. These variable payments related to the economic option would not be included in the FCM. Capacity payments for a PPA are intended to mimic payments for the fixed costs of a facility and, for solar generation, the majority of the costs are fixed. However, if Staff's primary concern is that the Company's proposal includes PPA payments that are not tied to fixed costs, the Company is willing to stipulate that it will exclude the marginal cost associated with producing any energy for purposes of calculating an FCM.” 7 TR 749-750.

The Company is not, contrary to some parties' claims, trying to include the entire array of PPA costs in the calculation of the FCM regardless of the character of the costs. The calculation of the FCM should include all costs for which the Company has a fixed contractual payment obligation.

Second, Staff, ABATE, and the Attorney General claim the 25% risk factor used in the Company's FCM calculation is too high. However, the 25% risk factor was not developed by the Company. That is the actual risk factor that S&P applies to Consumers Energy when calculating imputed debt for purposes of S&P's credit rating for the Company. Exhibit A-115 (SM-6). Mr. Maddipati explained that rating agencies provide credit ratings of the Company's debt, and those credit ratings can often be used by investors to gauge the creditworthiness of a company. 7 TR 751. He testified that the credit ratings are intended to reflect the ability of a company to repay its debts. 7 TR 751. Mr. Maddipati explained that, to the extent any credit agency was purposefully assigning credit ratings that were either too high or too low, then over time the reliability of those ratings would be less useful for investors and they would rely on other gauges or rating agencies. 7 TR 751. In other words, credit rating agencies have a business interest in ensuring the accuracy and credibility of their ratings. Mr. Maddipati testified:

“Rating agencies’ adjustments, including adjustments for off-balance sheet items such as PPAs, are intended to improve their analysis in assessing the creditworthiness of a company. Mr. Harlow’s commentary seems to insinuate rating agencies are somehow purposefully overstating debt and that doing so would somehow be ‘in favor of investors’ – which simply lacks any support in his direct testimony or elsewhere in the record. It should cause the Commission pause that the primary support offered by Mr. Harlow for his opinion that a 25% risk factor is too high is to suggest that S&P is misapplying its own guidelines.”  
7 TR 751.

Notably, Staff witness Robert F. Nichols II testimony discussed several states that calculate imputed debt and, of the ones he mentioned, the risk factors ranged from 20% to 30%. 7 TR 752. In any case, because S&P specifically uses 25% with respect to Consumers Energy, then that is the factor that will determine the Company's actual imputed debt experience. If the goal is to address the impact of Consumers Energy's imputed debt, it does not matter whether S&P's thinking behind the 25% factor is correct or incorrect. It only matters that the Company's actual imputed debt is consistent with the results using S&P's 25% factor.

**d. Response To Staff's Claim That The FCM Does Not Align With The Intent Of Act 341**

Staff witness Harlow claims that the Company's proposed FCM is not consistent with the requirements of Act 341. Act 341 provides, among other things, that a PPA incentive mechanism may not "exceed the utility's weighted average cost of capital." MCL 460.6t(15). Staff claims that the Company's proposed FCM results in a return that is much larger than the Company's Weighted Average Cost of Capital ("WACC"), but Mr. Harlow's analysis erroneously attempts to apply the Company's most recently approved WACC rate to the wrong base. Mr. Maddipati explained in his rebuttal testimony:

"Page 11 of my direct testimony clearly demonstrates that the Company's proposed mechanism does not exceed its WACC. Cost of capital rates are applied to capital balances (i.e., debt and equity), not expense balances. While I am not a lawyer, if, as indicated by Mr. Harlow, the law intended to cap any FCM as the PPA expense times the Company's WACC it could have said so explicitly. Rather, it notes that '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.' Such a statement would only make sense if you were to treat a PPA as creating a capital asset, which is what I have done by calculating the imputed debt of the PPA. By using the authorized ROE and an equity-to-debt ratio less than currently authorized, I have ensured that the resulting FCM would, by definition, be less than WACC." 7 TR 752-753.

The Company's WACC is composed of a WACC *rate* multiplied by the Company's invested capital. Therefore, it is simply an inaccurate calculation to try to compare the WACC rate to a different rate, which is applied to a base that is not comparable to a value that represents a proxy for the invested capital of a PPA. Staff is incorrectly comparing apples and oranges.

e. **Response To GLREA's Claim That The FCM Should Not Be Applied To PURPA Contracts**

GLREA witness Rafson argues in his testimony that, even if the Commission approves the Company's proposed FCM, it should not be applied to new PURPA contracts. Mr. Torrey responded to this claim in his rebuttal testimony. Mr. Torrey testified:

"In his direct testimony, Company witness Troyer explains there are over 1.2 GWs of QF projects interested in selling capacity to the Company at current avoided cost rates, a significant portion of the Company's supply resources. The Company acknowledges its requirement to comply with PURPA as implemented by the MPSC. The Company also acknowledges that it is not willing to abandon the traditional regulatory model for such a significant portion of its business. As noted above, the PCA includes a competitive solicitation process to select new capacity resources and set the PURPA avoided cost based on a three-year outlook. Entering into PURPA agreements with new QFs displaces either Company-owned or purchased capacity, forgoing the Company's opportunity to earn a return on its capital investment or an FCM on a PPA. The RFP process is expected to result in lower costs by allowing the Company to leverage lower cost technologies, or avoid procuring capacity in the event demand does not materialize as forecasted in this IRP. Further, MCL 460.6(t) does not restrict the type of PPA on which the Company can earn a return. The FCM is an integral part of the PCA and RFP process. In order to move away from the traditional regulatory model, the FCM should apply to all PPAs." 8 TR 1488-1489.

GLREA's proposal to exclude new PURPA PPAs from the operation of the FCM should be rejected for the reasons stated by Mr. Torrey.

**f. The Commission Should Not Adopt The Alternative PPA Incentive Mechanisms Proposed By Staff Or Other Parties**

Finally, several parties proposed alternative forms of an incentive mechanism for future PPAs that they recommend the Commission might implement in lieu of the Company's proposed FCM. The common theme in all of these proposals is that they are inadequate to achieve the two purposes for implementing the FCM as described by Company witnesses Torrey and Maddipati. As many of the other parties acknowledged, any incentive mechanism implemented by the Commission in this case needs to be sufficient to overcome the problem inherent in traditional utility regulation that utility earnings are tied to owned assets, and it also need to recognize that PPAs created hidden costs in the form of imputed debt impacts on the Company's credit and on the need for the Company's equity to support those PPAs. Staff's and other parties' proposals simply do not achieve those requirements.

In addition to Staff's proposal to allow the Company to own up to 50% of all new generating assets under the IRP, which is discussed in an earlier section of this Initial Brief, Staff proposed two other possible alternatives for an incentive mechanism applicable to new PPAs.

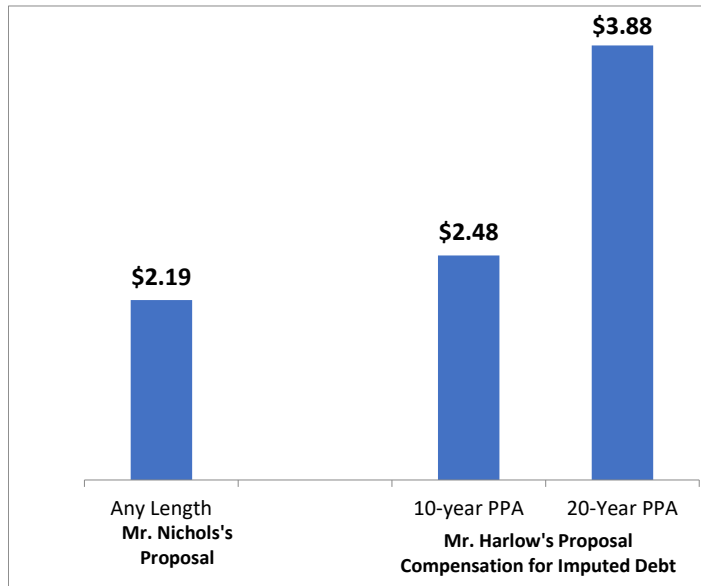
Mr. Maddipati summarized Staff's alternatives as follows:

- “• Staff's [sic] proposes that the Commission ignore imputed debt in analyzing a PPA. Staff witness Nichols proposes an FCM by incorporating 12 months of qualifying PPA expenses as a regulatory asset and thus allowing the Company a return on this regulatory asset;
- “• Staff also suggests that, if imputed debt is to be included, the Commission utilize the methodology proposed by Staff witness Harlow, which modifies my methodology by using a risk factor of 15% and only including 50% of any PPA payment . . . .”  
7 TR 744.

The Company does not agree with these alternatives because they do not provide adequate incentives to support the need for the FCM.

Mr. Maddipati addressed Staff’s alternative PPA incentive mechanisms in his rebuttal testimony. He testified:

“While Staff may disagree that imputed debt should be addressed as part of this case, Mr. Proudfoot, Mr. Nichols, and Mr. Harlow all provide evidence that imputed debt is considered by regulatory commissions and credit agencies. Staff witness Harlow provides direct testimony outlining a proposed method for calculating an FCM based on imputed debt. While I have criticism of Mr. Harlow’s direct testimony, which I’ll address later in my rebuttal, for a 10-year PPA with a \$60/MWh price, his calculation for the FCM is \$2.48/MWh (Exhibit S-9.1) and for a 20-year PPA, Mr. Harlow’s proposal would result in an FCM of \$3.88/MWh. Mr. Nichols’ FCM on the other hand would result in an FCM of \$2.19/MWh regardless of the term of the PPA, which is less than Staff’s own calculation for the costs of imputed debt.

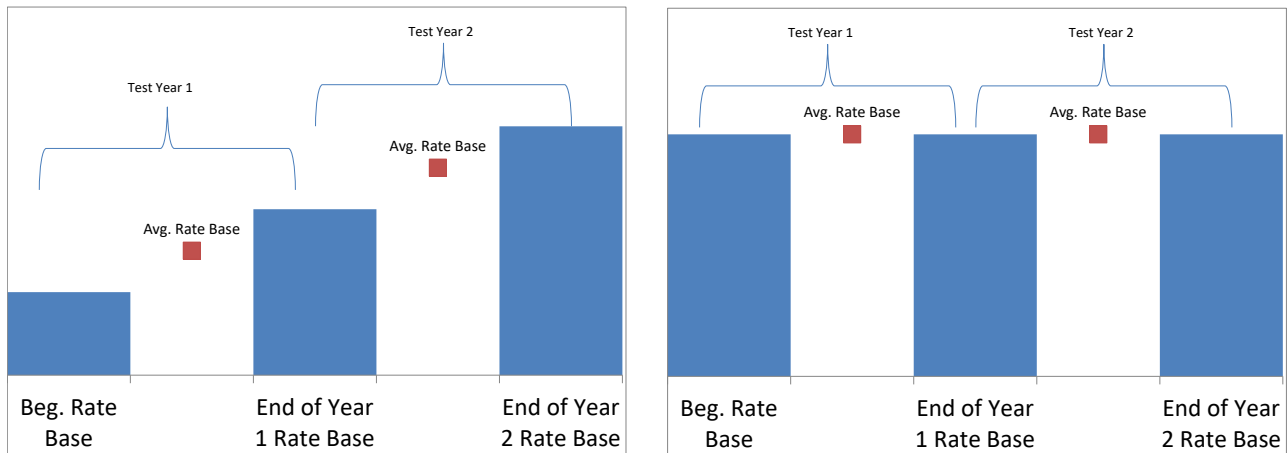


“Figure 2: Comparison of FCM proposed by Staff.

“Mr. Nichols suggests his proposed FCM is a reasonable alternative but provides no rationale for why offering an FCM lower than Mr. Harlow’s calculation for imputed debt would incentivize the use of PPAs, which costs more to customers and investors.” 7 TR 745-746

Mr. Maddipati also found certain inconsistencies in Staff’s proposed methodology that would need to be addressed if the Commission were to use it as an alternative to the Company’s

proposed FCM. First, Mr. Maddipati noted that Mr. Nichols proposes including qualifying PPA expenses for the consecutive 12-month projected test year period as a regulatory asset. Mr. Maddipati explained that, in effect, this means an annual PPA payment would be included as regulatory asset for the duration of the PPA. 7 TR 746. However, Mr. Maddipati points out that Staff witness Nichols then suggests that as a result of averaging for rate base calculations this would result in the Company earning on 50% of this annual payment. 7 TR 746. Mr. Maddipati testified that, while Mr. Nichols is correct that rate base is averaged over 13 months in a general rate proceeding, the rationale for doing so is that rate base is changing over the course of the test year and therefore the average represents the rate base during that test year. 7 TR 746. However, Mr. Maddipati explained that a PPA is generally expected to be a level payment and therefore including 12 consecutive months of a PPA payment as a regulatory asset would result in an average rate base that is the same as the annual PPA payment. 7 TR 747. Mr. Maddipati illustrated the discrepancy in the results by including the following figures in his testimony:



7 TR 747, 748.

Second, Mr. Maddipati explained that Mr. Nichols' methodology uses the pre-tax WACC of the Company's total capital structure rather than the pre-tax WACC of the Company's permanent capital structure. 7 TR 748. The Company's total capital structure includes deferred

taxes, which are generated predominantly by capital expenditures. 7 TR 748. Mr. Maddipati notes, however, that Staff and Mr. Nichols appear to be strongly against treating PPAs as capital assets financed off-balance sheet (i.e., imputed debt). 7 TR 748. Mr. Maddipati testified, “Mr. Nichols’ treatment of PPA expenses as a regulatory asset would not generate any new deferred taxes that I’m aware of for Consumers Energy and therefore at a minimum his analysis should have used the pre-tax WACC of the Company’s permanent capital structure.” 7 TR 748. Mr. Maddipati included the following table in his testimony illustrating the two adjustments:

	<u>Mr. Nichols Proposed</u>	<u>Comments</u>	<u>Revised</u>
Illustrative PPA Price	\$60		\$60
x % of Payment	50%	Incorrectly averages a constant payment	100%
x P-T WACC (U-18424)	<u>7.29%</u>	Uses Total Capital Structure vs. Permanent Capital Structure	<u>9.27%</u>
<b>FCM</b>	<b>\$2.19</b>		<b>\$5.56</b>

7 TR 749.

Mr. Maddipati concluded that “[t]o the extent the Commission believes including 12 months of PPA payments as a regulatory asset is a methodology that warrants consideration, at a minimum the two adjustments I’ve made would be required to meet this rationale.” 7 TR 749.

ELPC/MEC witness Jester proposed a similar alternative to the FCM to Mr. Nichols’ proposal. However, Mr. Jester’s alternative incorporates the modifications proposed by Mr. Maddipati above. Mr. Maddipati testified:

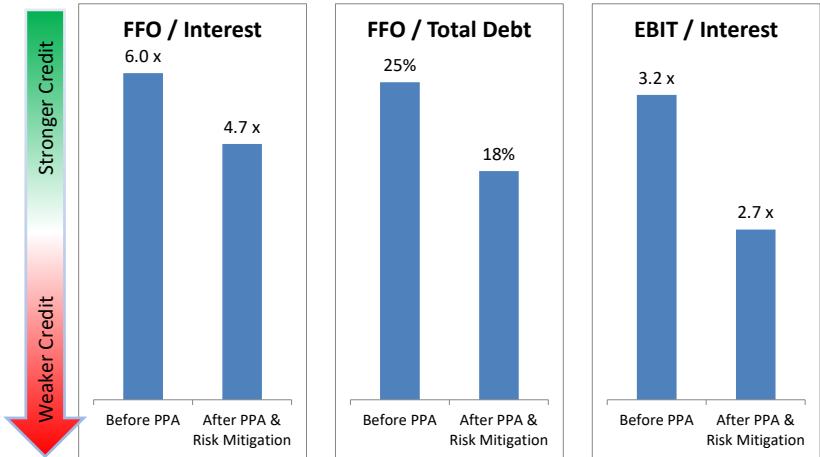
“Mr. Jester applies the Company’s pre-tax WACC using its permanent capital structure to the PPA payments. While this method offers simplicity, it still results in a PPA payment that does not incorporate the length of the PPA contract, which would potentially impact the ultimate costs transferred to the Company and its rate payers. Mr. Jester’s proposal could be plausible to the extent the Commission decided PPA terms would not exceed

10 years or if coupled with Mr. Proudfoot’s proposal to allow the Company to own up to 50% of its generation resources and allow for competitive bidding on the remainder with his proposed FCM.”  
7 TR 758-759.

Therefore, while the adjustments offered by Mr. Maddipati are clearly supported as improving the alternative proposals of various parties, these proposals are still inferior to the FCM proposed by Consumers Energy in this case.

Mr. Jester also proposed some alternative methods of mitigating the effects of imputed debt. However, Mr. Maddipati noted that they are inadequate to protect the Company from a degradation in its credit ratios. He testified:

“Mr. Jester does not provide any documentation from S&P, and when asked in discovery if he had spoken to anyone at any rating agency prior to developing his direct testimony, he indicated he had not. Mr. Jester does go on to cite from a report prepared by the staff of the California Public Utilities Commission, which outline methods for incorporating imputed debt. While he seems to suggest that his alternative strategies are cheaper methods for restoring credit, he simply fails to note that the two methodologies both result in degradation of credit ratios. In fact, the credit metrics resulting from one of Mr. Jester’s “risk mitigation” strategies are in fact considerably lower as shown in Exhibit MEC-3, page 14, and illustrated in the charts below.



“While Mr. Jester is certainly correct that his methodology for incorporating imputed debt would result in a lower FCM, it clearly

does not fully address the credit impacts created by PPAs.”  
7 TR 759-760.

Again, the Commission should reject any alternatives proposed by the parties that fail to meet the objectives that the Company’s FCM is design to meet.

SEIA witness Lucas recommended that the Commission should limit any type of PPA incentive mechanism solely to the recovery of any administrative costs that the utility might incur. Mr. Torrey provided the following response in his rebuttal testimony:

“The recovery of only administrative costs related to the RFP would be grossly inadequate to allow the Company to move away from a traditional regulatory model. Deferring the issue to a future rate case (where cost of capital is determined) sets a level of uncertainty that is unacceptable. Mr. Lucas acknowledges on page 59, lines 16 through 17, that under a traditional vertically-integrated regulatory structure, there are limited incentives for utilities to do anything other than build and own assets and that importantly the IRP statute provides such an incentive. It follows that the incentive should be established in the IRP proceeding, not deferred to some other forum. As discussed in my rebuttal of SEIA witness Gignac, Consumers Energy will not abandon the traditional regulatory model and move forward with the new avoided cost methodology and RFP process without approval of the FCM incentive as proposed in the PCA.” 8 TR 1487.

As with the other proposals discussed above, Mr. Lucas’ proposal should be rejected because it simply does not provide an adequate incentive to the Company to achieve the reasons for adopting a PPA incentive mechanism in the first place.

**g. Conclusion**

As discussed in detail above, the arguments of Staff and other parties against the adoption of the Company’s proposed FCM are without merit and should be rejected. For all of the reasons discussed in Section III.E. of this Initial Brief and in this section responding to other parties, the Commission should approve the Company’s proposed FCM for all new PPAs entered into after the date of the Commission’s final order in this case.

(i.) **Rate Impact Of PCA**

(a.) **Response To Attorney General**

In his direct testimony, Attorney General witness Coppola argues that traditional ratemaking treatment of the remaining net book value of Karn Units 1 and 2 moderates the impact on customer rates versus regulatory asset treatment. 8 TR 2358-2359 and 2383.

As Ms. Myers explained in her rebuttal testimony:

“Exhibit A-57 (HJM-3) shows that the Company’s proposed regulatory asset approach with an amortization through 2031 provides a lower total revenue requirement and net present value of the revenue requirement stream than traditional ratemaking treatment. In addition, the Company is not opposed to amortizing the regulatory asset through 2039.” 7 TR 1050.

Thus, because the Company’s proposal provides for lower total revenue requirements and NPV of the revenue stream than traditional ratemaking treatment, and because the Company is not opposed to amortizing the regulatory asset through 2039, the Attorney General’s argument is without merit and should be rejected by the Commission.

(ii.) **Response To ABATE**

ABATE witness Pollock, presented ABATE’s position regarding rate impacts for traditional ratemaking versus regulatory asset treatment. Mr. Pollock begins by saying “[b]y the year 2033, electric rates are projected to increase by nearly 22% relative to current rates.” 8 TR 2100, 2115-2116. Mr. Pollock bases his projection, which diverges from that of the Company, on “current rates,” arguing that the Company’s analysis (Exhibit A-55 (HJM-1)) “was measured relative to the proposed revenue requirements in the pending electric rate case (U-20134).” 8 TR 2115. He also argues that his separation of impacts into PSCR-related costs and other fixed costs (non-PSCR), “illustrates the different risks to customers.” 8 TR 2116. According to Mr. Pollock, by the year 2025, the PCA would increase current rates by about

1.0 cent per kWh, which is “about 7.7% higher than current rates.” 8 TR 2116. Further, he argues that, “[b]y 2033, the cumulative rate increase would be 2.77 cents per kWh, which is about 22% higher than current rates.” 8 TR 2116; Exhibit AB-3.

As Ms. Myers explained in her rebuttal testimony, Mr. Pollock’s assumption that the Company was not using current rates in its calculation is in error. In fact, Ms. Myers testified that the “Company’s percentage increases provided on Exhibit A-55 (HJM-1), line 2, are measured relative to current rates.” 7 TR 1051. This calculation by the Company results in a 15.65% increase by 2033. Ms. Myers explained that the revenue requirement based on current rates was calculated by taking the base rate and power supply cost revenue requirement approved in the Company’s last electric rate case adjusted for the impacts of the Tax Cuts and Jobs Act. 7 TR 1051.

Ms. Myers further disagreed with Mr. Pollock’s position that the primary cause of upward rate pressure of the PCA is a nearly \$7 billion projected increase in projection plant. 8 TR 2114. As Ms. Myers explained, “[w]hile there is nearly \$7 billion in incremental capital investment, this is not the proper amount to compare to current net plant.” 7 TR 1051. In fact, incremental capital investment should not be compared to net plant; instead, net plant should be compared to net plant. 7 TR 1052. Ms. Myers further explained that there is incremental accumulated depreciation of \$3 billion included in the PCA; therefore, incremental net plant is \$4 billion (\$7 billion incremental capital investment less \$3 billion incremental accumulated depreciation). 7 TR 1052. Thus, when the appropriate \$4 billion incremental net plant is compared to the current net plan presented by Mr. Pollock it does not equate to the 168% increase in incremental investment projected by Mr. Pollock for 2039. See 8 TR 2114; 7 TR 1052. Similarly, Mr. Pollock’s use of a \$1.6 billion revenue requirement, associated with the

proposed Karn Units 1 and 2 regulatory asset, in his calculation of the projected rate impacts is also in error. See 8 TR 2116. As Ms. Myers explained in her rebuttal testimony:

“It would not be appropriate to include the \$1.6 billion total revenue requirement in the incremental rate impacts of the PCA. Current rates include \$126,542,000 for Karn Units 1 and 2. If the current revenue requirement is in place through 2031, the time period proposed in the regulatory asset treatment of Karn Units 1 and 2, the collection would be higher than the \$1.6 billion associated with the proposed regulatory asset. Therefore, the regulatory asset proposal does not provide any incremental revenue requirement impacts over current rates.” 7 TR 1052.

Additionally, Mr. Pollock questioned the affordability of the PCA in light of his calculation of the projected rate impacts. 8 TR 2117. In disagreement with Mr. Pollock, Ms. Myers presented a chart in her rebuttal testimony and explained,

“First, the Company’s filing in this case supports the PCA as the best course forward. Second, for reasons stated previously, rate impacts shown on the Company’s Exhibit A-55 (HJM-1) should be relied on when analyzing affordability. Exhibit A-55 (HJM-1) shows that, with the exception of one year, the largest year-over-year increase would be less than 2%, and it provides a compound annual growth rate of less than 0.70%. Third, it is important to also consider a total bill comparison when relating Consumers to other utilities. Chart 1 below shows that, since 2017, the Company has maintained a lower total average monthly bill than utilities in the state, in the midwest, and in the country.” 7 TR 1053 (chart omitted).

Because Ms. Myers fully rebutted Mr. Pollock’s calculations and recommendations, ABATE’s recommendations should be rejected by the Commission.

**(a.) Transmission-related Recommendations**

For purposes of analyzing the resource adequacy needs for Michigan in the context of Consumers Energy’s IRP, METC witness Charles Marshall testified that he had “a comprehensive LOLE analysis . . . conducted consistent with the MISO process . . .” 8 TR 2499. Based on this analysis, Mr. Marshall indicated that “[a]bsent improvements to the transmission

system to support the CIL, and acceptable LOLE cannot be achieved.”<sup>28</sup> 8 TR 2499. As discussed by Mr. Lynd in his rebuttal testimony, however, while Mr. Marshall’s Loss of Load Expectation (“LOLE”) study is informative as it may provide an early indicator of the impacts a generation resource plan may have on LOLE and CIL (6 TR 690), numerous facets of Mr. Marshall’s approach call into question the accuracy of his conclusions and should, thus, not be accepted by the Commission.

For example, in his direct testimony, Mr. Marshall walks through the elements of his MISO Transmission Expansion Planning (“MTEP”) model analysis and his conclusions. 8 TR 2500-2513. He begins by stating that he selected two study years, 2018 and 2032, to analyze current resource adequacy needs for Michigan and to analyze the resource adequacy needs for Michigan in 2032. 8 TR 2500. He explained that he “analyzed 2032 because it is the furthest-out year analyzed by MISO in its MTEP process [footnote omitted] for generation and transmission expansion planning for all of Michigan.” 8 TR 2501. As Mr. Lynd explained, however, the use of 2032 in his analysis creates distorted and inaccurate results. While Mr. Lynd agreed that MISO does publish future year models, “its models are only as good as the quality of the portfolio of projects and network modifications submitted by member utilities and adjoining regional transmission organizations (‘RTO’).” 6 TR 684. He said:

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<sup>28</sup> LOLE is the expected number of days per time period (usually a year) for which the available generation capacity is insufficient to serve the demand at least once per day. LOLE counts the days having loss of load events, regardless of the number of consecutive or nonconsecutive loss of load hours in the day. The majority of entities conducting LOLE studies primarily use LOLE to establish resource adequacy criteria. Criteria development entities may also leverage other metrics and factors in their criteria development to determine a sufficient reserve margin to maintain an adequate level of system reliability. LOLE generally helps inform integrated resource planning, market-based resource procurement, generator interconnection queue projects, and other planning activities. *North American Electric Reliability Corporation (NERC) April, 2018, Probabilistic Adequacy and Measures Technical Reference Report (Final)*, pages 14-18. [https://www.nerc.com/comm/PC/Documents/2.d\\_Probabilistic\\_Adequacy\\_and\\_Measures\\_Report\\_Final.pdf](https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf)

“MTEP project queue typically represents projects in the two-to seven-year horizon. Given the quantity of network projects that are submitted to MISO each year, the 2032 model referenced most certainly does not contain all transmission modifications and upgrades that will be in-service in 14 years. Each year MISO transmission owners, including METC, make upgrades to the transmission system in order to mitigate emerging baseline reliability issues and connect new generation. These changes can alter the capacity of the transmission system. Likewise, changes to the PJM Regional Transmission Organization transmission network adjoining MISO Local Resource Zone 7 (‘LRZ7’) in lower Michigan, can also impact the import capabilities of LRZ7.” 6 TR 684-685.

Thus, Mr. Lynd concluded, “[w]ithout all modifications and upgrades included, the model utilized does not represent the state of the transmission system in the year 2032 and, therefore, cannot provide conclusive results.” 6 TR 685.

Additionally, Mr. Marshall expresses concern about MISO’s annual LOLE analysis, which includes a CIL assessment, but calls that analysis “very shortsighted.” 8 TR 2513. He primarily focuses on the time period between a planned retirement and the time MISO receives notice of such a retirement, saying that this “provid[es] [MISO] little time to plan, consider and implement transmission solutions to support the CIL. 8 TR 2513. While Mr. Lynd agreed that the generation retirement process at MISO may impact CIL assessments, he noted that:

“MISO does not allow generation retirement to negatively impact the reliability of the transmission system. If a generation retirement causes a transmission reliability deficiency, that generation unit is designated as a System Support Resource, and remains on-line until the required transmission system upgrades are completed to remedy the identified deficiencies.” 6 TR 685.

Thus, there is already a mechanism in place to prevent transmission reliability issues/deficiencies, and Mr. Marshall’s concerns regarding MISO’s planning time to consider and implement transmission solutions to support CIL is not a material threat.

Further, Mr. Marshall testified that METC was unable to conduct a detailed analysis for the PCA, which included 5,100 MW of solar and 550 MW of wind, because he was without knowledge of where these prospective solar and wind farms may be sited. He argued that based on this lack of siting information, “METC was unable to represent an estimated investment required to support the interconnection of these resources.” 8 TR 2518-2519. As Mr. Lynd explained, however, an IRP is not a siting study, and the use of average network costs is appropriate in an IRP. 6 TR 685; 6 TR 675-676. In fact, Mr. Lynd stated that “[a]ctual network upgrades needed and their costs for transmission-connected resources will be determined through MISO interconnection processes as those resources are connected to the transmission system.” 6 TR 685-686.

Finally, Mr. Lynd disagreed with Mr. Marshall’s:

- Future year modeling of the Ludington Pumped storage plant because Mr. Marshall’s analysis shifted the historical pumping and generating profile for Ludington forward four hours instead of three as indicated by MISO’s Renewable Integration Impact Assessment (6 TR 686);
- Addition of only 75 MW of unforced proxy generating capacity to achieve the target LOLE, as it is much less than MISO’s last two published LOLE reports (6 TR 686-687);
- Assertion that LRZ7 should increase to 4,000 MW, especially when his own analysis indicate that CIL need only be 3,321 MW in 2032 (6 TR 687);
- Expectation that transmission tie lines will be utilized in an “increased capacity” to support Michigan, as “it is not clear that there is sufficient clarity of all of the various parameters that impact CIL over the next fourteen years to confirm this expectation” (6 TR 687-688);
- Assertion that the strategic deployment of Static VAR Compensators to increase voltage stability on the transmission system is a cost effective means to increase the CIL, because of the lack of evidence that Mr. Marshall’s LOLE study was repeated with the identified SVCs in-service (6 TR 688);

- Assessment that SVCs are the best solution to increase CIL for LRZ7 (6 TR 688-689); and
- Assessment that the Company’s PCA is resource deficient and that “[a]bsent improvements to the transmission system to support the CIL, an acceptable LOLE cannot be achieved” (6 TR 690).

Again, while Mr. Lynd indicated that the LOLE study presented by Mr. Marshall is informative and may provide an early indicator of the impacts a generation resource plan may have on LOLE and CIL, “METC does not necessarily provide the regional view of transmission, peer review, and stakeholder input to these studies that MISO does provide.” 6 TR 690. As Mr. Lynd explained:

“Not only are SVCs not needed immediately, as the potential deficiency presented by Mr. Marshall is fourteen years into the future, but it has not been clearly demonstrated that SVCs are the correct solution. MISO, through its annual MTEP process and annual study of LOLE, provides a periodic opportunity for not only transmission owners, but also all impacted distribution and generator owners, to review and react. Additionally, MISO’s LOLE working group annually provides a five-year outlook for LOLE which provides time to react to any insufficient LOLE or CIL values. Transmission owners and stakeholders can then propose appropriate transmission or generation solutions to MISO.” 6 TR 690-691.

Company witness Blumenstock similarly disagreed with Mr. Marshall’s analysis. Specifically, in response to Mr. Marshall’s suggestion that the IRP should be used to assess future CIL needs, and recommendation for transmission projects to increase CIL, Mr. Blumenstock testified that the IRP is not an appropriate forum to assess recommended upgrades to CIL. 6 TR 281. As Mr. Blumenstock explained:

“The IRP is the appropriate forum for determining utility capacity needs and corresponding plans to meet those needs. The Company believes CIL analysis and any recommended transmission system upgrades to increase CIL provide valuable context in an IRP, but these topics should be ultimately analyzed and approved through various MISO efforts, including the LOLE Working Group,

Attachment Y analysis, or the MISO Transmission Expansion Planning forum.” 6 TR 281.

Overall, as Mr. Blumenstock testified, the Company is participating in MISO working groups to address issues such as those raised by Mr. Marshall. 6 TR 280. In fact, Mr. Blumenstock explained that “[a] Consumers Energy employee chairs the Loss of Load Expectation (“LOLE”) working group at MISO and is an industry expert in the topics raised by Mr. Marshall.” 6 TR 280. Further, the Company participates in the MISO MTEP process where any transmission issues such as those raised by Mr. Marshall will be resolved. 6 TR 280. Finally, the Company has had meetings directly with MISO executives, and at various MISO stakeholder meetings, where it continues to advocate for market reforms for successfully integrating renewables into the MISO energy and capacity markets. 6 TR 280-281.

Mr. Blumenstock said that:

“The Company is being proactive in support of the filed PCA and advocating for needed market reforms to make supply portfolios successful such as those proposed in the PCA. Through these efforts, the Company will make the PCA successful and should there be any changes in assumptions, will be able to incorporate them into future IRPs.” 6 TR 281.

While the Company is willing to communicate and collaborate with METC as requested, METC’s LOLE study has a number of deficiencies that make the study informative but should not be substituted for the information and analyses provided by MISO.

**(b.) Removal Of Distributed Generation Cap**

Throughout the course of this proceeding, GLREA argues that the cap on distributed generation should be lifted. See 8 TR 2442; 8 TR 2456. This is contrary to statute. MCL 460.1173(3) states that an electric provider is not required to allow for a distributed generation program that is greater than 1% of its average in-state peak load for the preceding five years. This statutory provision cannot be revised in this proceeding.

In addition to the statutory language, there is no need for the distributed generation cap to be lifted in this case. Company witness Hatcher testified that there is only one utility in Michigan, Upper Peninsula Power Company, to reach net metering cap – and this was met for Category 1 customers. 8 TR 1726. A review of the Company’s net metering program participants further shows that removal of the distributed generation cap is unnecessary. Company witness Hatcher testified:

“Per the MPSC Distributed Generation Program Report for Calendar Year 2017 dated Oct 15, 2018, though the total program participation grew by 35% from 2016 to 2017, Consumers Energy had 84% of the program’s Category 1 (0kW-20kW system sizes) space remaining available to customers and 72% remaining for Category 2 (20kW-150kW system sizes) customers.” 8 TR 1725.

Thus, it is unnecessary to even contemplate further expansion of the distributed generation cap as there is currently ample room for customer participation.

**(c.) Recommendations For Future IRP Filings**

Company witness Blumenstock addressed numerous recommendations provided by Staff and ELPC regarding issues to be considered in future IRP proceedings. In most cases, the Company is in agreement with the recommendations provided by these parties. However, in some instances the Company has rejected portions of certain proposals or proposed modifications. The following provides a summary of the positions with respect to the issues.

**(d.) Response To Staff**

Staff’s first recommendation, as presented by Staff witness Lynn M. Beck, requests that the Company explicitly state whether it received any alternate proposals as part of the IRP process in future IRPs. 9 TR 2597. The Company did not address any alternative proposes in this IRP because the Company was not presented with any alternative proposals. However, the

Company is in agreement with this recommendation and will indicate whether or not it received any alternative proposals in the Company's future IRP filings. 6 TR 264.

At 9 TR 2598, Ms. Beck noted that the Company provided a value-added resource with its filing which allowed readers to track and index the reporting requirements. Staff requests adoption of a Staff created version of the Company's index, which includes page number references, as opposed to just the testimony section references included in the Company's index. The Company will agree to continue providing this value-added resource with future IRP filings; however, the Company does not entirely agree with Staff's proposal to include testimony page references. 6 TR 264-265. Since testimony page numbers can be fluid up until the day of a filing, the Company believes that the inclusion of page numbers in the index could be onerous and could cause filing delay. The Company does not support requiring page number reference in the index as a filing requirement but will endeavor to include page numbers in the index in future IRP filings, to the extent possible. 6 TR 265.

With respect to the transmission analysis performed by METC, Ms. Beck suggested that the Company could have "...specified proxy locations for the injection of solar energy into the transmission system to gain relevant information about the impact of a resource configuration that resembles the Proposed Cause of Action and its impact to the electrical system." 9 TR 2599-2600. Mr. Blumenstock explained that, while there were limiting factors which prevented Staff's recommended level of collaboration in the development of this IRP, the Company does not disagree with Staff's recommendation and sees the value in gaining insight into its PCA's impact on the electrical system. 6 TR 265-266. Therefore, in future IRP filings, the Company will provide specific interconnection information to METC if it is known. 6 TR 266.

At 9 TR 2601, Ms. Beck further recommended that the Company “work with METC to determine more specific interconnection costs by resource type, specifically solar generation, to be used in future IRPs.” The Company agrees with this recommendation, and will continue to work with both METC and MISO to ensure that interconnection costs are considered as the Company moves forward with diversifying its resource portfolio as it has proposed in its PCA. 6 TR 266.

Moreover, at 9 TR 2604, Ms. Beck recommended that the Company “...continue to work with METC to conduct a study that more closely analyzes the impact the Proposed Course of Action has on the electrical system, including the evaluation of projects that could increase the capacity import limit as well as other projects that may increase the ability to purchase energy from the market.” Mr. Blumenstock explained that, in developing this IRP case, the Company collaborated with METC to evaluate projects that could increase CIL and will continue to collaborate with METC in support of future IRP filings. 6 TR 266-267.

With respect to the public outreach process encouraged in the Commission’s IRP filing requirements, Staff witness Sarah A. Mullkoff recommended that the Company “improve its process for collecting comments by offering additional mediums for stakeholder participation.” The Company agrees with this recommendation and will employ additional mediums for collecting comments in future IRPs. 9 TR 2617.

At 9 TR 2616, Ms. Mullkoff addressed the filing of annual reports as required by MCL 460.6t(14) and recommended that, if required by the Commission, the Company should file annual reports which “include at a minimum, the status of the approved resources additions with any cost, schedule, or megawatt (MW) size updates including any deviations from the original projections in the 3-year period for which IRP costs are approved.” Furthermore, at

9 TR 2617, Ms. Mullkoff recommended that “the Company provide immediate communication to Staff and the Commission if there is a significant change or anticipated change to the expected cost, timing, or size of any resource additions in its IRP.” In response to these recommendations, Mr. Blumenstock indicated that the Company is more than willing to maintain transparency with both the Commission and Staff, and the Company understands the need for the Commission and its Staff to remain aware of the status of resource additions. 6 TR 268. Therefore, the reporting recommendation, if required and adopted by the Commission, is acceptable to the Company.

At 9 TR 2645, Staff witness Makinde recommended that the Company “continue to monitor the transmission system capabilities and changes within the MISO energy market that could impact the Company’s PCA.” The Company agrees to this recommendation. 6 TR 268. Mr. Blumenstock also explained that monitoring the MISO market and transmission system capabilities are an integral course of daily business and the Company will continue this practice as the PCA progresses. 6 TR 268.

Staff witness Naomi J. Simpson addressed the use of a Michigan workforce in the implementation of a resource plan at 9 TR 2656 and recommended that in the future, “the Company directly address how it will facilitate the use of Michigan’s workforce as it continues to implement the PCA in future IRP filings.” In response, Mr. Blumenstock explained that, to the extent feasible, the Company agrees to address whether 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 in future IRP filings. 6 TR 268.

With respect to the risk assessment performed in the development of the IRP, Ms. Simpson recommended that the Company “perform a risk assessment that will utilize aspects of both deterministic and stochastic analyses in tandem to assure that the PCA remains

cost effective amidst changing future parameters.” 9 TR 2661. In response, Mr. Blumenstock indicated that the Company intends to include stochastic risk analysis in future IRPs. 6 TR 269. However, Mr. Blumenstock also noted that if it is believes that stochastic analyses provide for a more robust risk analysis, the Commission’s IRP filing requirements should be updated so that all entities filing IRPs are held to the same standard. 6 TR 269.

At 9 TR 2679, Staff witness Zachary C. Heidemann indicated that it “would expect that, absent such an order or other documented justification, in the future a more holistic retirement analysis would be presented for all fossil generation in the ET scenario.” The Company opposes this suggestion because the current IRP filing requirements and mandated planning parameters do not require the Company to include a retirement analysis with its IRPs. 6 TR 269. Mr. Blumenstock explained that the only reason the Company included retirement analysis in its current IRP is because the Commission directed the Company to do so in Case No. U-18322. The Company is of the position that requiring such an analysis in all future IRP filing is unnecessary and would lead to a burdensome debate about the disposition of approved assets or re-justifying assets in rate base, which is not the purpose of an IRP. 6 TR 269.

Finally, at 9 TR 2818, Staff witness Matthews recommended that the Company “rework its modeling to include the co-optimized dispatch of renewables and battery storage, as well as investigate residential scale storage programs that can be implemented across its service territory in its next IRP.” The Company agrees with this recommendation regarding renewables and battery storage and recognizes that there are synergies between these resources. However, the Company does not believe that residential-scale storage is sufficiently mature enough to warrant modeling in the IRP. 6 TR 270. This is due to the fact that the Company currently has no residential-scale storage programs and the fact that MISO does not have market mechanisms to

support wide-scale battery storage. 6 TR 270. Mr. Blumenstock explained that once residential-scale storage is sufficiently mature, with developed programs and market mechanisms in place, the Company expects this resource to be included in future IRPs. 6 TR 270.

(e.) **Response To ELPC**

At 8 TR 2308-2309, ELPC witness Daniel proposes the following recommendations for the Company's next IRP: (i) file an application for review of a new IRP within the next three years; (ii) issue a RFPs or quotations for wind each year until the application for review of the next IRP is filed; (iii) allow the model to select wind as an economic option in all scenarios in all future IRPs; (iv) run all optimized portfolios in all scenarios for future IRPs; (v) include a non-zero carbon price in all scenarios, or at the very least in the reference case; and (vi) apply carbon prices system-wide. These recommendations are addressed below.

With respect to Mr. Daniel's first proposal, Mr. Blumenstock explained that if the Company's PCA is approved, the Company intends to file a new or amended IRP within three years. 6 TR 271. However, if aspects of the Company's proposed filing are not approved, the three-year filing cadence will have to be revisited, and at a minimum, the Company will file every five years as required by MCL 460.6t. 6 TR 271.

Mr. Blumenstock addressed Mr. Daniel's second proposal regarding wind resources and explained that the Company's annual solicitations will be based upon the resources approved plan. 6 TR 271. Since the Company's PCA relies on the procurement of solar resources, the Company does not agree to including proposals for wind generation, as Mr. Daniel recommends. 6 TR 271. However, the Company's competitive bidding proposal would permit a proposal for wind generation from a PURPA QF no greater than 20 MW, even if the PCA does not include wind generation.

The Company agrees to Mr. Daniel's third recommendation which is to allow the model to select wind as an economic option in all scenarios in all future IRPs. Mr. Blumenstock explained that, in future IRPs, the Company intends to allow the expansion planning software to select wind resources in all scenarios. 6 TR 271.

The Company disagrees with Mr. Daniel's fourth and fifth recommendations. Mr. Blumenstock explained that, due to the very similar expansion plans resulting from the model, it would not provide new insights or results not already presented by the Company to run optimized portfolios through all scenarios provides additional data. 6 TR 272. Furthermore, the Company does not agree with requiring modeling of carbon pricing in all scenarios or system-wide. 6 TR 272. However, if required by the Commission, or warranted by existing or proposed environmental regulation, the Company will include carbon pricing or a carbon cap in future IRPs.

## **V. CONCLUSION**

As the first IRP filed in Michigan pursuant to Act 341, this case represents a historic opportunity to reshape Michigan's energy future. The Company's PCA presents a fundamental shift in the resources which make up the Company's capacity resource portfolio, and also proposes to dramatically change the way the Company procures capacity moving forward. The PCA will provide customers with clean, affordable, and reliable electricity through 2040 and represents the best plan for Michigan.

For the reasons discussed in this Initial Brief, and as set forth in the evidence presented by the Company, the Commission should approve the Company's PCA in its entirety, because the PCA represents the most reasonable and prudent means of meeting the Company's energy

and capacity needs through 2040. As part of its approval of the PCA, the Company specifically requests the Commission to make the following determinations:

- (i) Approve as reasonable and prudent for cost recovery purposes the Company's proposed EWR, DR, and CVR costs which will be commenced by the Company within three years following the Commission's approval of the Company's IRP;
- (ii) Approve the Company's proposal to recover the unrecovered book balance of Karn Units 1 and 2, including decommissioning costs, and proposed regulatory accounting treatment through 2031;
- (iii) Approve the Company's proposed competitive-bid methodology for determining avoided costs rates and for determining and addressing the Company's capacity position pursuant to PURPA;
- (iv) Approve the utilization of a five-year period for the purpose of determining the Company's capacity position and related obligations pursuant to PURPA and find that the Company has no PURPA capacity need so long as the Company is implementing the PCA, as approved by the Commission;
- (v) Approve the Company's FCM for any new PPAs entered by the Company; and
- (vi) Grant the Company such other relief as set forth in this Initial Brief and the Company's record evidence.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Dated: December 21, 2018

By: \_\_\_\_\_  
Bret A. Totoraitis (P72654)  
Robert W. Beach (P73112)  
Anne M. Uitvlugt (P71641)  
Gary A. Gensch (P66912)  
Theresa A. G. Staley (P56998)  
Michael C. Rampe (P58189)  
One Energy Plaza  
Jackson, Michigan 49201  
Attorneys for Consumers Energy Company  
(517) 788-1846

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	Case No. U-20165
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t and for other relief	)	
_____	)	

**PROOF OF SERVICE**

STATE OF MICHIGAN     )  
   ) SS  
 COUNTY OF JACKSON    )

Samantha J. O’Rourke, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on December 21, 2018, she served an electronic copy of the **Initial Brief of Consumers Energy Company** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein. She further states that she also served a hard copy of the same document to the Hon. Sharon L. Feldman at the address listed in Attachment 1 by depositing the same in the United States mail in the City of Jackson, Michigan, with first-class postage thereon fully paid.

\_\_\_\_\_  
 Samantha J. O’Rourke

Subscribed and sworn to before me this 21<sup>st</sup> day of December, 2018.

\_\_\_\_\_  
 Melissa K. Harris, Notary Public  
 State of Michigan, County of Jackson  
 My Commission Expires: 06/11/20  
 Acting in the County of Jackson

**ATTACHMENT 1 TO CASE NO. U-20165**

**Administrative Law Judge**

Hon. Sharon L. Feldman  
Administrative Law Judge  
7109 West Saginaw Highway  
Post Office Box 30221  
Lansing, MI 48909  
E-Mail: feldmans@michigan.gov

**Counsel for the Michigan Public  
Service Commission Staff**

Spencer A. Sattler, Esq.  
Amit T. Singh, Esq.  
Daniel E. Sonneveldt, Esq.  
Heather M.S. Durian, Esq.  
Assistant Attorneys General  
7109 West Saginaw Highway  
Post Office Box 30221  
Lansing, MI 48909  
E-Mail: sattlers@michigan.gov  
singha9@michigan.gov  
sonneveldtd@michigan.gov  
durianh@michigan.gov

**Counsel for Attorney General,  
Bill Schuette**

Celeste Gill, Esq.  
Assistant Attorney General  
Michigan Dept. of Attorney General,  
Special Litigation Unit  
6<sup>th</sup> Floor Williams Building  
Post Office Box 30755  
Lansing, MI 48909  
E-Mail: Gillc1@michigan.gov  
AG-ENRA-Spec-Lit@michigan.gov

**Consultant for Attorney General, Bill  
Schuette**

Sebastian Coppola, President  
Corporate Analytics  
5928 Southgate Road  
Rochester, MI 48306  
E-Mail: sebcoppola@corpalytics.com

**Counsel for the Great Lakes Renewable  
Energy Association**

Don L. Keskey, Esq.  
Brian W. Coyer, Esq.  
Public Law Resource Center PLLC  
333 Albert Avenue, Suite 425  
East Lansing, MI 48823  
E-Mail:  
donkeskey@publiclawresourcecenter.com  
bwcoyer@publiclawresourcecenter.com

**Counsel for the Cadillac Renewable  
Energy, LLC, Genesee Power Station  
Limited Partnership, Grayling  
Generating Station Limited  
Partnership, Hillman Power Company,  
LLC, TES Filer City Station Limited  
Partnership, Viking Energy of Lincoln,  
Inc., and Viking Energy of McBain, Inc.**

Thomas J. Waters, Esq.  
Anita G. Fox, Esq.  
Fraser Trebilcock Davis & Dunlap, P.C.  
124 W. Allegan Street  
Lansing, MI 48933  
E-Mail: twaters@fraserlawfirm.com  
afox@fraserlawfirm.com

**Counsel for the Michigan  
Environmental Council, the Sierra  
Club, and the Natural Resources  
Defense Council**

Christopher M. Bzdok, Esq.  
Lydia Barbash-Riley, Esq.  
Kimberly Flynn, Legal Assistant  
Karla Gerds, Legal Assistant  
Olson, Bzdok & Howard, P.C.  
420 East Front Street  
Traverse City, MI 49686  
E-Mail: chris@envlaw.com  
Lydia@envlaw.com  
kimberly@envlaw.com  
karla@envlaw.com

**ATTACHMENT 1 TO CASE NO. U-20165 (Continued)**

**Counsel for Midland Cogeneration  
Venture Limited Partnership**

Richard J. Aaron, Esq.  
Jason T. Hanselman, Esq.  
John A. Janiszewski, Esq.  
Dykema Gossett PLLC  
201 Townsend Street, Suite 900  
Lansing, MI 48933  
E-Mail: raaron@dykema.com  
jhanselman@dykema.com  
jjjaniszewski@dykema.com

Charles E. Dunn, Esq.  
Midland Cogeneration Venture, LP  
100 Progress Place  
Midland, MI 48640  
E-Mail: cedunn@midcogen.com

**Consultant for MCV**

Emily S. Medine  
Principal  
Energy Ventures Analysis, Inc.  
1800 Beechwood Blvd.  
Pittsburgh, PA 15217  
E-Mail: emedine@evainc.com

**Counsel for the Association of Businesses  
Advocating Tariff Equity (“ABATE”)  
and Gerdau Macsteel, Inc.**

Bryan A. Brandenburg, Esq.  
Michael J. Pattwell, Esq.  
Clark Hill PLC  
212 East Grand River Avenue  
Lansing, MI 48906  
E-Mail: bbrandenburg@clarkhill.com  
mpattwell@clarkhill.com

**Consultant for ABATE**

Jeffrey C. Pollock  
Billie S. LaConte  
Kitty A. Turner  
J. Pollock, Inc.  
12647 Olive Boulevard, Suite 585  
St. Louis, MO 63141  
E-Mail: jcp@jpollockinc.com  
bsl@jpollockinc.com  
KAT@jpollockinc.com

**Counsel for Cypress Creek Renewables.  
LLC and Solar Energy Industries  
Association**

Jennifer Utter Heston, Esq.  
Fraser Trebilcock Davis & Dunlap, P.C.  
124 West Allegan, Suite 1000  
Lansing, MI 48933  
E-Mail: jheston@fraserlawfirm.com

**Counsel for Energy Michigan**

Timothy J. Lundgren, Esq.  
Laura A. Chappelle, Esq.  
Varnum, LLP  
The Victor Center, Suite 910  
201 North Washington Square  
Lansing, MI 48933  
E-Mail: tjlundgren@varnumlaw.com  
lachappelle@varnumlaw.com

**Counsel for Independent Power  
Producers Coalition of Michigan**

Laura A. Chappelle, Esq.  
Varnum, LLP  
The Victor Center, Suite 910  
201 North Washington Square  
Lansing, MI 48933  
E-Mail: lachappelle@varnumlaw.com

**ATTACHMENT 1 TO CASE NO. U-20165 (Continued)**

**Counsel for Michigan Chemistry Council**

Timothy J. Lundgren, Esq.  
Varnum, LLP  
The Victor Center, Suite 910  
201 North Washington Square  
Lansing, MI 48933  
E-Mail: [tjlundgren@varnumlaw.com](mailto:tjlundgren@varnumlaw.com)

**Michigan Energy Innovation Business  
Council and Institute for Energy  
Innovation**

Laura A. Chappelle, Esq.  
Toni L. Newell, Esq.  
Varnum, LLP  
The Victor Center, Suite 910  
201 North Washington Square  
Lansing, MI 48933  
E-Mail: [lachappelle@varnumlaw.com](mailto:lachappelle@varnumlaw.com)  
[tlnewell@varnumlaw.com](mailto:tlnewell@varnumlaw.com)

**Counsel for Environmental Law & Policy  
Center, Ecology Center, Union of  
Concerned Scientists, and Vote Solar**

Margrethe Kearney, Esq.  
Unimuke John Agada, Legal Assistant  
Environmental Law & Policy Center  
1514 Wealthy Street SE, Suite 256  
Grand Rapids, MI 49506  
E-Mail: [mkearney@elpc.org](mailto:mkearney@elpc.org)

Bradley Klein, Esq.  
Environmental Law & Policy Center  
35 East Wacker Drive, Suite 1600  
Chicago, IL 60601  
E-Mail: [bklein@elpc.org](mailto:bklein@elpc.org)

**Michigan Electric Transmission  
Company, LLC**

Richard J. Aaron  
Courtney F. Kissel  
Dykema Gossett PLLC  
201 Townsend St. Suite 900  
Lansing, MI 48933  
E-Mail: [raaron@dykema.com](mailto:raaron@dykema.com)  
[ckissel@dykema.com](mailto:ckissel@dykema.com)

**Counsel for Residential Customer  
Group**

Don L. Keskey, Esq.  
Brian W. Coyer, Esq.  
Public Law Resource Center PLLC  
333 Albert Avenue, Suite 425  
East Lansing, MI 48823  
E-Mail:  
[donkeskey@publiclawresourcecenter.com](mailto:donkeskey@publiclawresourcecenter.com)  
[bwcoyer@publiclawresourcecenter.com](mailto:bwcoyer@publiclawresourcecenter.com)

**Counsel for the Sierra Club**

Michael Soules, Esq.  
1625 Massachusetts Avenue NW, Suite 702  
Washington, DC 20036  
E-Mail: [msoules@earthjustice.org](mailto:msoules@earthjustice.org)