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March 4, 2019

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

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 **Exceptions 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,

Digitally signed by Robert W. Beach
Date: 2019.03.04 16:33:36 -05'00'

Robert W. Beach

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

S T A T E   O F   M I C H I G A N

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

EXCEPTIONS OF CONSUMERS ENERGY COMPANY

March 4, 2019

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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

EXCEPTIONS OF CONSUMERS ENERGY COMPANY

I. INTRODUCTION AND OVERVIEW

On June 15 2018, Consumers Energy Company ("Consumers Energy" or the "Company") filed the first Integrated Resource Plan ("IRP") in the state of Michigan pursuant to MCL 460.6t of Public Act 341 of 2016 ("Act 341"). The Company's Proposed Course of Action ("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. The Company is requesting that the Michigan Public Service Commission ("MPSC" or the "Commission") approve the PCA in its entirety, because the PCA represents the most reasonable and prudent way to meet the Company's energy and capacity needs through 2040. The Company further 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 cost 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 Company's Financial Compensation Mechanism ("FCM") for any new Power Purchase Agreements ("PPAs") entered by the Company; and

(vi.) Grant the Company such other relief as set forth in its briefs and the Company's record evidence.

After evidentiary hearings, Initial and Reply Briefs were filed on December 21, 2018 and January 11, 2019, respectively. On February 20, 2019, Administrative Law Judge Sharon L. Feldman ("ALJ") issued a Proposal for Decision ("PFD") which, among other things, recommended the rejection of the Company's IRP. The PFD's recommendation is unreasonable, and the Commission should reject the PFD and approve Consumers Energy's IRP.

Consumers Energy is filing these Exceptions under the schedule established by the ALJ. The Company takes exception to all recommendations in the PFD which reject, or are otherwise inconsistent with, the Company's proposals as presented in the record and the Company's briefs.

II. <u>OVERVIEW OF COMPANY REQUESTS</u>

Consumers Energy has presented a PCA which will transform 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. The PFD recommends the rejection of the Company's IRP in its entirety. See PFD, page 292. The Commission should reject this recommendation. Before addressing the individual findings of the ALJ , the following outlines the Company's PCA and requested relief in this proceeding.

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. Moreover, because the PCA proposes the retirement of Karn Units 1 and 2 in 2023 before the end of the 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's PCA also proposes a plan to backfill the capacity lost by the expiration of the extended Midland Cogeneration Venture Limited Partnership ("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 proposes 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.

The Company is also seeking 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.

The PCA also proposes 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. The Company and the Commission Staff ("Staff") generally agree on the future determination of PURPA avoided cost rates and related issues. The following details the areas of agreement:

- Staff supports the Company's proposal to set the updated, full avoided cost rate based on the highest priced winning bid in each competitive solicitation. If the Company meets its desired capacity need after a competitive solicitation, the avoided cost of capacity should be set at the Midcontinent Independent System Operator, Inc. ("MISO") Planning Resource Auction ("PRA") clearing price, while energy should be based on the MISO Locational Marginal Price ("LMP") or a forecast of IRP marginal energy prices. Staff's Revised Initial Brief, pages 50, 55. Staff further indicated that "…should the Company not have a capacity need between RFPs, QFs would still be able to receive an avoided energy price for a five-year contract based on a forecast of MISO LMP or a 15-year contract using actual LMP, and they would receive a capacity price using the MISO PRA for both options." Staff's Revised Initial Brief, page 54;[1]

- Staff agrees with the Company that existing Qualifying Facilities ("QFs") that currently have contracts would be compensated at the most recently approved full avoided cost regardless of capacity need. Staff's Revised Initial Brief, page 54;

- Staff agrees with the Company that the Standard Offer maximum project size should be set at 150 kW or less. Staff's Revised Initial Brief, page 58;

- Staff supports shortening the capacity planning horizon to five years and the Company has agreed to this capacity planning horizon based on the conditions explained by Staff. Staff's Revised Initial Brief, page 59. In discovery, Staff witness Jesse J. Harlow explained the conditions that would be used in conjunction with the five-year capacity planning horizon 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." Exhibit A-110 (KGT-7);

- Staff supports the Company's competitive bidding proposal to procure new capacity and the parties are aligned on the use of annual solicitations. Staff's Revised Initial Brief, pages 50-51. Staff also supports the Company's proposed Request for Proposal ("RFP") process as open and unbiased. Staff's Revised Initial Brief, page 53;

- Staff agrees that the PPA term should align with the Company's depreciation schedules (which in this case is for solar facilities). Staff's Revised Initial Brief, page 52;

[1] Staff also agrees that if the Company's proposed avoided cost methodology is not approved, the inputs to the Case No. U-18090 method need to be updated. Staff's Revised Initial Brief, page 54.

- Staff agrees with the Company that the cost and value of resources should be considered when analyzing bids received through the competitive solicitations. Staff's Revised Initial Brief, page 52; and

- Staff agrees with the Company that "[r]equiring the Company to purchase all 1.8 gigawatts in its interconnection queue at the previously approved full avoided cost rate would render the preferred plan useless and potentially have negative impacts on ratepayers…" Staff's Revised Initial Brief, page 56.

Since the Company is proposing a competitive-bid framework for the future procurement of capacity, the Company is also seeking approval of a proposed FCM on PPAs. 6 TR 260. The Company's proposed FCM would calculate a fixed charge when the Commission approves a PCA and would apply to the life of the PPA. 7 TR 727. 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 used 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. The result of the Company's proposed calculation would be a levelized cost for the FCM applied over the life of the PPA.

While the Company continues to support its proposed FCM, the Company has made clear in the record that the alternative FCM proposed by Michigan Environmental Council, Natural

Resources Defense Council, and Sierra Club (collectively, "MEC") witness Douglas B. Jester, which can be calculated at 9.27% (see 7 TR 749), is acceptable if coupled with Staff witness Paul A. Proudfoot's proposal to allow the Company to own up to 50% of its generation resources and allow for competitive bidding of the remaining 50% with Mr. Jester's FCM. In addition, the Company also indicated that an FCM of 9.27% could be reasonable with a PPA term which does not exceed 10 years in length. 7 TR 759.

The Company's PCA is an integrated proposal that ties the evolution of the Company's resource portfolio to many proposals in this case (i.e., recovery of Karn Units 1 and 2 remaining book balance, competitively bidding capacity procurement, a new methodology for determining avoided costs under PURPA, and an 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. Thus, the Company reserves the right to abandon or amend its PCA if the Commission rejects any of the Company's proposals in this IRP.

III. EXCEPTIONS TO THE PFD

A. Time Period Of PCA Approval

1. The PFD Erred In Finding That The Commission's Authority To Approve An IRP Is Limited To A 15-Year Period

On pages 144 through 148, the PFD addressed a dispute regarding the appropriate approval period of an IRP. As discussed above, the Company has sought approval of its PCA as the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. Staff proposed that the Commission provide "explicit approval for only the first three years of the plan" (9 TR 2543) and MCV argued that the approval of an IRP does not equate to the approval of a long-term resource plan. 9 TR 2905. The PFD found that the IRP approval period is limited to at most a 15-year period. PFD, page 147.

The Company disagrees with the PFD's conclusion. While the PFD is correct that the Company must file five, ten, and 15-year projections of the Company's load obligations and a plan to meet those obligations as part of an IRP, this requirement does not limit the Commission's ability to approve a longer IRP period. Since the Commission's Integrated Resource Planning Parameters, as approved in Case No. U-18418, require utilities to provide projections of 20 years in length, the Commission's approval of an IRP should also encompass a 20-year period.[2] MPSC Case No. U-18418, November 21, 2017 Order, page 46 ("November 21 Order"). While the PFD points out that the Company initially objected to the Commission requiring 20-year projections as inconsistent with the law (see PFD, page 148), the Commission rejected the Company's arguments. See November 21 Order, page 56. Since the Commission has determined that it has the authority to require 20-year projections in the context of an IRP proceeding, it follows that the Commission would also have the authority to approve a resource plan which spans 20 years. To decide otherwise renders the last five years of the required 20-year IRP projection period meaningless.

[2] The Company is not of the position that pre-approval of costs, as provided in MCL 460.6t(11), would extend to 20 years. MCL 460.6t(11) clearly indicates that such cost pre-approvals are limited to costs "commenced within 3 years after the Commission's order approving the initial plan, amended plan, or plan review."

B. PCA

1. Development Of PCA

a. Transmission Analysis

(i.) The PFD's Finding That The Company Failed To Comply With Filing Requirements Related To Its Transmission Analysis Is In Error

The PFD concludes that "Consumers Energy has not complied with MCL 460.6(5)(h) or (j)[3] and the Commission's filing instructions requiring an analysis of transmission system options and anticipated costs." PFD, page 296. This conclusion is unsupported by the record evidence and is in error.

To be clear, MCL 460.6t(5)(h) states,

> "(5) An integrated resource plan shall include all of the following:
>
> ***
>
> "(h) An analysis of potential new or upgraded electric transmission options for the electric utility."

The Commission's filing instructions, "Section XII Transmission Analysis," specifies what this analysis is to include to satisfy Section (5)(h). It states, in relevant part,

> "In accordance with MCL 460.6t(5)(h), the utility shall include an analysis of potential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:
>
> "(a) The utility shall assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options;

[3] This should be MCL 460.6t(5)(h) or (j).

“(b) A detailed description of the utility’s efforts to engage local transmission owners in the utility’s IRP process in an effort to inform the IRP process and assumptions, including a summary of meetings that have taken place;

“(c) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns;

“(d) Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, subject to confidentiality provisions;

“(e) Any information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility’s IRP by:

“(1) increasing import or export capability;
“(2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs;
“(3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and
“(4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources.”

Additionally, MCL 460.6t(5)(j) requires the Company to provide the following with its filing:

“(j) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements.”

The Company fulfilled the Commission’s filing requirements as follows:

1. Statutory section 5(h)/filing requirement XII(a) states: "The utility shall assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options." The Company fulfilled this filing requirement with the testimony and exhibits of Company witness Donald J. Lynd. See 6 TR 672-676; Exhibit A-97 (DAL-2). As discussed by Mr. Lynd in his direct testimony, the Company utilized Michigan Electric Transmission Company's ("METC") transmission analysis as valuable information related to the impact of generation unit retirement, coupled with the addition of generation at various sites. As Mr. Lynd further explained, "[t]hese 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 675. Mr. Lynd found the level of investment projected by METC to be reasonable and, in fact, Mr. Lynd's cost assumption of $54,000/MW of generation capacity fell within the range of network upgrade costs presented by METC in its Transmission Evaluation. While Mr. Lynd disagreed with a number of elements of METC's transmission analysis, the Company nonetheless found the results informative for development of the IRP. The Company, thus, complied with this filing requirement and the PFD's determination that the Company did not comply with this filing requirement is unsupported by the record and in error.

2. Statutory section 5(h)/filing requirement XII(b) requires: "A detailed description of the utility's efforts to engage local transmission owners in the utility's IRP process in an effort to inform the IRP process and assumptions, including a summary of meetings that have taken place." The Company also fulfilled this filing requirement in the testimony and exhibits of Mr. Lynd. See 6 TR 672-675; Exhibit A-96 (DAL-1). The Company met with METC four

times between November 2017 and April 2018 as part of the IRP process. The notes of those interactions are in the record as Exhibit A-96 (DAL-1). The PFD's determination that the Company failed to meet this filing requirement is unsupported by the record and in error.

3. Statutory section 5(h)/filing requirement XII(c) requires the Company to provide the Commission information regarding: "Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns." The Regional Transmission Organization ("RTO") is MISO. The Company fulfilled this filing requirement in the testimony of Mr. Lynd. See 6 TR 677-680. Overall, Mr. Lynd determined that there is an abundance of Capacity Import Limit ("CIL") not being utilized. 6 TR 679. He further indicated that increasing CIL to accommodate remote supply sources could affect reliability. 6 TR 679. As Mr. Lynd indicated, METC suggested increasing CIL to satisfy resource adequacy requirements and suggested increasing CIL for Local Resource Zone 7 ("LRZ7") by 1000 MW through adding static Volt Ampere Reactive ("VAR") compensators at a cost of approximately $150 million. 6 TR 680; Exhibit A-97 (DAL-2), page 3. As Mr. Lynd explained, this would benefit METC and ITC Holdings Corporation Transmission ("ITCT"), as they would construct the static VAR compensators and, thus, be able to include the rates for these capital costs in their charges for transmission service; however, Mr. Lynd indicated that CIL was not needed to provide the necessary supply for LRZ7 and, thus, this proposed transmission cost to increase CIL would derive no benefit to ratepayers, but would increase customer rates. 6 TR 680. Mr. Lynd concluded that the Company's PCA does not require capacity at or near the CIL and, therefore, concluded that "it would be imprudent to make investments to increase the CIL." 6 TR 680. Because Mr. Lynd thoroughly addressed CIL, including a response to METC's recommendations for CIL, the Company disagrees with the

PFD's conclusion that the Company "has not established that it has reasonably considered capacity import restrictions in its plan." This conclusion is in error and unsupported by the record.

4. Statutory section 5(h)/filing requirements XII(d) and (e) require the Company to provide the Commission:

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

This information was provided and discussed in the testimony and exhibits of Mr. Lynd. See 6 TR 674-681; Exhibit A-97 (DAL-2). As discussed by Mr. Lynd in his direct testimony, METC did not offer any information regarding transmission upgrades resulting in increasing system efficiency and reduced line loss, and did not provide the Company with any information regarding advanced transmission network technologies that could affect resources, other than the deployment of static VAR compensators to increase CIL, which was also discussed in Mr. Lynd's testimony. Because this information was part of the record and supports the filing requirements, the PFD's determination that the Company failed to fulfill this filing requirement is not supported by the record and is in error.

5. Statutory section 5(j) requires the Company to include in its filing: "Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements." The PFD focused on this filing requirement as it is "related to transmission," and also determined that the Company had not met the filing requirements as to this information. PFD, pages 158, 296. The cost estimate for generation capacity that was used for all generation technologies located in Michigan was $54,000/MW. 6 TR 675. The arrival at this cost was discussed by Mr. Lynd in his direct testimony at 6 TR 675-676. While Mr. Lynd's credentials to determine this amount were not disputed, his status as an expert was not under any scrutiny, and the origin of the cost assumption of $54,000/MW of generation capacity used by the Company was explained as being based on not only figures used by METC in its transmission analysis, but also based on other reputable sources, the PFD found "that the $54,000/MW transmission upgrade cost the company used in its modeling as arbitrary, reflecting essentially a *meaningless* average from a broad range of network upgrade costs taken from Generator Interconnection Agreements that may not be required for or applicable to the generation at issue." PFD, page 161 (emphasis added). This does not arise to the level of failure to meet filing requirements. Because the Company did present record evidence supporting this filing requirement, the PFD's determination that the Company did not meet his filing requirement is unsupported by the record and in error.

Staff witness Lynne M. Beck also testified that Consumers Energy's transmission analysis met the filing requirements. See 9 TR 2598-2603. Staff made suggestions for the Company to work with METC in the future in three areas. 9 TR 2603-2605. These recommendations denote a need for improvement in developing information regarding impacts of the PCA on the electrical system and development of costs. These recommendations, which were accepted by the Company (see Consumers Energy's Reply Brief, pages 157-158; 6 TR 266-267), do not convey a lack of such information, nor do they mean that the Company failed to meet filing requirements.

Although the PFD recognizes that "several parties argue that MISO will determine the CIL and LOLE requirements," and acknowledges MISO as the "ultimate decision-maker," the PFD then disregards this information and refers to "hidden costs" related to competitive bidding, speculates on the accuracy of the Company's projections, and criticizes the Company for failing to give METC "all potentially available[4] information . . . including . . . likely location of new generation." PFD, pages 160-161. While Staff indicated an interest in the Company providing "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 Course of Action and its impact to the electrical system," Staff did not conclude that the Company's filing was deficient. Instead, Staff suggested that the Company "work with METC to determine more specific interconnection costs by resource type, specifically solar generation, to be used in future IRPs." 9 TR 2600, 2604; Staff's Revised Initial Brief, page 22. The Company accepted this recommendation. See Consumers Energy's Reply Brief, pages 157-158;

[4] The Company is unclear regarding what the PFD means by providing METC with all "potentially available" information.

6 TR 266-267. The PFD does not explain why future improvements in these areas equates to a failure to meet statutory filing requirements.

The PFD erroneously concludes that the Company did not meet the filing requirements for transmission analysis. A typical conclusion that a filing requirement was not met would normally suggest a void where an applicant was supposed to provide certain information, but did not. A careful review of the PFD, however, shows that the criticism appears to be less focused on the existence of information provided by the Company to support its transmission analysis, and more on the substance of the analysis provided, favoring METC's analysis over that of the Company. The PFD appears to be troubled over the extent to which the Company included METC in the Company's transmission analysis, even independently advocating and arguing[5] that the Company should have sought an extension of its deadline for filing its IRP to accommodate METC's analysis so as not to "waste" METC's time. See PFD, page 159. METC's transmission study was not a waste of time. In fact, the Company made clear that the study was "informative" in assessing new generation and cost. See 6 TR 674; Consumers Energy's Initial Brief, pages 53-54; Consumers Energy's Reply Brief, page 145. The Company's transmission analysis is intended more for informing the Company of what may impact transmission plans in the future. Because this is the Company's first IRP, it is unsurprising that a few adjustments in certain analyses, including the transmission analysis, will be helpful in the future and, as shown by the Company, it is willing to implement Staff's suggestions for those adjustments in the future. Concluding that the Company failed to meet filing requirements, however, is not based on record evidence, and should not be accepted by the Commission.

[5] No other party, including METC, suggested a schedule delay to accommodate its analysis.

b. <u>Evaluation Of Storage Resources</u>

(i.) <u>The PFD Erred To The Extent It Found That The Company's Evaluation Of Storage Resources Supports Rejecting The IRP</u>

The PFD also determined that the Company "did not properly evaluate storage as an accompaniment to the renewable resources included in its plan." PFD, page 163. In support of this conclusion, the ALJ relied on the testimony of Staff witness Cody S. Matthews. PFD, pages 162-163. Mr. Matthews testified that while Staff is generally supportive of the Company's planned renewable resources, Staff believes 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 as a result the Company may have "prematurely pushed battery storage to later years in the IRP." 9 TR 2816-2817.

Staff recommended that "the Company rework its modeling to include the co-optimized dispatch of renewables and battery storage . . . in its next IRP." 9 TR 2819. Consumers Energy agrees that its current modeling only considered the energy and capacity value that storage provides, and the Company is determining ways in which to model other benefits of storage. 6 TR 499. Consumers Energy expects 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 optimization 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 way in which the Company modeled storage technology in this IRP does not support the Commission rejecting the IRP. Notably, Staff did not recommend rejection of the IRP as a result of how the Company modeled storage, but recommended that the Company "rework its modeling . . . *in its next IRP*." See 9 TR 2819 (emphasis added). And as Company witness Sara T. Walz testified, "the flexibility afforded by the PCA will permit the Company to leverage resources that may provide incremental values to customers, allowing the Company to more frequently analyze storage and examine any value-added products in the MISO markets that are added for storage." 6 TR 499-500.[6] While the PFD's discussion of the Company's evaluation of storage resources did not state that the Commission should reject the IRP as a result of such evaluation, the PFD generally "recommends that the Commission reject the company's IRP for the reasons explained above." PFD, page 292. The Commission should not adopt the PFD's recommendation that the IRP should be rejected as a result of the Company's evaluation of storage resources.

c. <u>CVR Resources</u>

(i.) <u>The PFD's Conclusion That The Commission Should Not Include The Planned CVR Reductions In This IRP Lacks An Evidentiary Basis And Is Inconsistent With The PFD's Recommendation That The Commission Should Pre-Approve CVR Capital Costs</u>

The PCA includes the use of CVR to achieve a total peak load reduction of 111 MW by 2028. 6 TR 259; 8 TR 1633; Exhibit A-70 (MAO-4). Consumers Energy seeks approval in this case of its CVR Program as part of the PCA, and approval of its CVR deployment costs 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. Consumers Energy's cost pre-approval

[6] Staff witness Matthews also recommended that the Company "investigate residential scale storage programs that can be implemented across its service territory in its next IRP." 9 TR 2819. The PFD did not address this recommendation. The Company does not believe that residential-scale storage is mature enough to warrant modeling in the IRP. 6 TR 270. The Company currently has no residential-scale storage programs and MISO does not have market mechanisms to support wide-scale battery storage. 6 TR 270. Company witness Richard T. 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.

request is only for costs associated with the CVR resources that the Company will incur in the three years subsequent to the Commission's approval of the IRP. Both Staff's Revised Initial Brief (page 40) and the Attorney General's Initial Brief (pages 24-25) supported the Company's request for pre-approval of capital costs of $8,924,600.

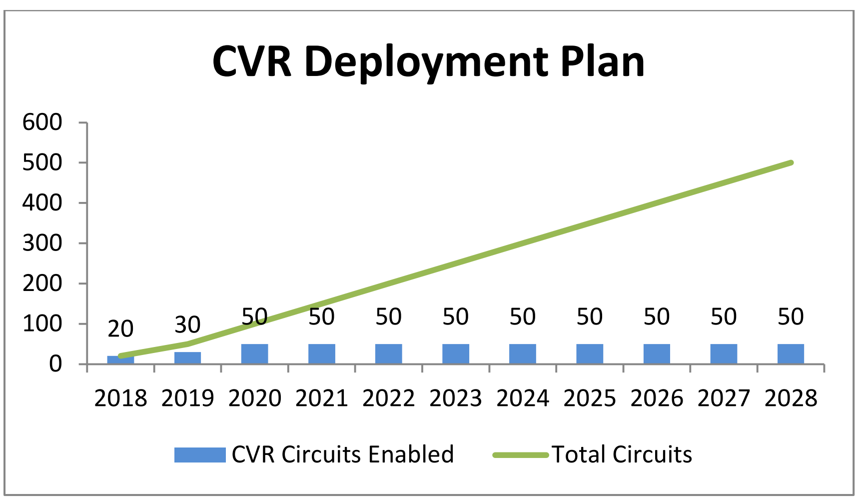
The PFD recommends that the Commission approve the Company's requested capital costs, but not the requested O&M costs, stating:

> "14. As discussed in Section X above, the ALJ recommends that the Commission adopt Staff's proposal that capital costs for the first three years for DR, EWR, and CVR be approved as reasonable in this IRP, but that O&M costs be reviewed in other proceedings; that the company's proposed regulatory asset for Karn units 1 and 2 be deferred to a rate case; and that Staff's reporting and modeling requests be generally granted as explained." PFD, page 298.

While the PFD recommends that the Commission approve the Company's requested capital costs for CVR deployment, it nevertheless states that "the PCA's reliance on CVR is premature and should not be approved until the company's next IRP, when the results of the ongoing pilot program can be reviewed." PFD, page 169.

The Commission should adopt the PFD's recommendation that it approve the Company's capital costs for the first three years of the IRP. For the reasons provided in Section III.B.6, below, the Commission should also approve the Company's CVR O&M costs, and not follow the PFD's contrary recommendation. Further, as explained below, the Commission should not adopt the ALJ's view that "reliance on CVR is premature and should not be approved until the company's next IRP," but should instead approve the inclusion of the CVR Program's projected MW savings in the Company's IRP in this case, as it is not supported by the record and is inconsistent with the PFD's recommendation that the Commission should pre-approve CVR capital costs .

Contrary to the PFD, Consumers Energy's CVR Program is not "premature," and there is no need to await the results of the Company's pilot program before including the CVR Program's projected MW peak savings in the Company's IRP in this case. The PFD appears to base its statement that the CVR Program is "premature" on the fact that the Company had not completed its pilot program. However, nothing in the record indicates that the pilot program is a pre-requisite to the Company's implementation of its CVR Program. The Company plans to achieve its peak load reductions through a measured implementation approach. The PCA calls for a gradual implementation, pursuant to which the Company would deploy up to 20 circuits beginning in 2018, 30 circuits in 2019, and ramping up to 50 circuits in 2020, with continued deployment of 50 circuits per year through 2028, for a total of 500 circuits over the 11-year period. 8 TR 1625; Exhibit A-70 (MAO-4). Company witness Mark A. Ortiz, Consumers Energy's Grid Modernization Program Lead, summarized the Company's plan for CVR deployment in the figure below (8 TR 1626):



As part of its reasonable and prudent CVR implementation strategy, the Company included a pilot program, but the fact that the pilot was not yet complete when the record closed did not somehow make its CVR Program "premature." Mr. Ortiz explained, for example, that the CVR pilot would enable the Company to take corrective measures in cases where frequent fluctuation voltage violations occur (8 TR 1637), but nothing in Mr. Ortiz's or any other witness' testimony provided any basis to conclude that the Company's implementation of CVR hinged on a pilot program. To the contrary, CVR is enabled by a proven set of technologies that utilities have used for decades (8 TR 1620-1621).

Critically, neither Staff's Revised Initial Brief nor Staff's Reply Brief advocated for the exclusion of the Company's CVR Program from this IRP. To the contrary, Staff stated that the Company's proposed CVR Program was "reasonable," and proposed only to "revisit" the CVR Program if the Company's pilot did not produce expected MW reductions. Staff's Revised Initial Brief, page 40. Thus, the PFD makes a recommendation that Staff did not even advocate, and the Commission should not adopt it.

In summary, the PFD correctly concluded that the Commission should pre-approve capital costs of $8,924,600 for CVR for the first three years of the IRP. The Commission should also pre-approve the requested O&M expenses, and include the planned CVR reductions in this IRP. As the Staff has noted, if the Company's next IRP warrants an adjustment, it can be revisited at that time.

d. Electric Vehicle Growth

(i.) The PFD's Finding That The Company's Forecast Is Deficient In Failing To Project Increases In Electric Vehicle Growth Is In Error

The PFD found "that Consumers Energy's forecast is deficient in failing to recognize projected increases in electric vehicles . . . ." PFD, page 175. In support of this conclusion, the PFD characterizes Company witness Eugene M. Breuring's testimony as follows: "[i]n forecasting the baseline energy and demand requirements, Mr. Breuring did not forecast electric vehicle growth, and contended that there is insufficient information to project an increase." PFD, page 174 (citation omitted). This, however, is not an accurate characterization of Mr. Breuring's testimony. While the PFD ultimately concluded that there is no "basis on this record to conclude that the deficiency is material," the PFD's analysis requires a response.

In his direct testimony Mr. Breuring stated,

> "Q. What are the Company's projections surrounding EVs, PHEVs, and/or BEVs?
>
> "A. 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.

This testimony does not suggest a lack of information; rather it indicates and recognizes the very preliminary stage of potential Electric Vehicle ("EV") growth in Michigan and takes a measured approach to EV growth by revealing that the Company "continues to monitor developments in this industry." The Company does so with the sources cited in Mr. Breuring's testimony and with the development of the Company's EV pilot program, approved by the Commission in Case No. U-20134. In fact, Mr. Breuring's testimony tracks what was provided in the Company's Electric Rate Case, Case No. U-20134, as it relates to EVs.

The PFD included information surrounding the Company's EV pilot program, as approved in Case No. U-20134. See PFD, page 175. As noted by the PFD, the Commission recognized in its January 9, 2019 Order in Case No. U-20134 that "EV adoption is in its infancy in Michigan." After a discussion of the possibilities for EVs in Michigan, the Commission noted in that same Order that, "[n]one of this will materialize until EV chargers become more prevalent and accessible." Managing the grid and promotions associated with EV charging and EV chargers are, in part, the purpose of the Company's EV pilot program approved by the Commission. Thus, Mr. Breuring correctly took a measured approach to EV growth, particularly when the state's infrastructure is still not developed to a point where the projections promoted by Solar Energy Industries Association ("SEIA") are reasonable. Thus, the Company's forecast is far from deficient, and the PFD's conclusion to the contrary is unsupported by the record and should not be accepted by the Commission.

2. <u>Medium 4 Retirement Analysis</u>

Consistent with the Commission's March 29, 2018 Order in Case No. U-18322, the Company's IRP included a Medium 4 Retirement Analysis.[7] Based on the results of the Company's analysis, the Company proposed to retire Karn Units 1 and 2 in 2023 and to continue operating Campbell Units 1 and 2 until 2031, consistent with the design lives of those units. On page 179, the PFD found that it is reasonable to retire Karn Units 1 and 2 in 2023. However, the PFD also found that "some critical assumptions underlying the company's modeling [of Campbell Unit 2] are not well-supported." The PFD thus recommended "that the Commission call for a revised analysis to review the potential savings associated with retiring Campbell unit 2." PFD, pages 193-195. For the reasons discussed below, the Company takes exception to the PFD's conclusion that the Company's Medium 4 Retirement Analysis was flawed and the PFD's recommended revised analysis.

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[7] In Case No. U-18322, the Commission required that the Company provide a retirement assessment of the Medium 4 units in this IRP case. See MPSC Case No. U-18322, March 29, 2018 Order, page 25.

a. <u>The PFD Erred In Finding That Critical Assumptions Underlying The Company's Retirement Analysis Modeling For Campbell Unit 2 Are Not Well-Supported</u>

The Company's Medium 4 Retirement Analysis was comprehensive, extensively supported, met the requirements of the Commission's March 29, 2018 Order in Case No. U-18322, and established that it is in the customers' best interests to operate Campbell Units 1 and 2 until 2031. Among other things, this analysis considered: ongoing capital expenditures and O&M expenses; different variations and combinations of unit retirements and retirement years; natural gas price sensitivities; capacity price sensitivities; an actual capacity replacement plan; the operational complexity of the Company's coal fleet; and eight additional factors mandated in Case No. U-18322. 7 TR 883-886. Based on this analysis, the Company determined that the economic justification for early retirement versus continued operation for any of the Medium 4 units is not overly compelling. 7 TR 887. This is because the results did not significantly favor continued operation or retirement. But to diversify the unit 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 retiring these units when compared to Campbell Units 1 and 2. 7 TR 889. The record does not establish that the Company's Medium 4 Retirement Analysis, particularly as it concerns Campbell Unit 2, is in any way flawed.

The PFD specifically errs in relying on MEC's arguments that Consumers Energy skewed its analysis in favor of continued operation at Campbell Units 1 and 2. The PFD cites, and appears to agree with, MEC's contentions that: (i) the IRP's lower projected spending at Campbell Units 1 and 2 is inconsistent with the Company's "optimistic assumptions about the Campbell units' future performance, particularly their projected heat rate" (MEC's Initial Brief, page 40); and (ii) non-environmental capital costs at Campbell Units 1 and 2 would be higher in

2018 and 2019 under a 2023 versus 2031 retirement scenario (MEC's Initial Brief, pages 35-36). PFD, pages 193-194. Both contentions, however, are unsupported by the record. The PFD errs in accepting them, and the Commission should reject them.

The Commission should reject the PFD's statement that the Company did not include adequate heat rate assumptions in its analysis. PFD, page 194-195. The PFD appears to have relied on MEC's position on this issue, which claimed that the Company's lower projected spending was inconsistent with the Company's projected improved heat rates at Campbell Units 1 and 2. MEC's Initial Brief, page 40. Neither MEC nor the PFD, however, cited any record evidence that the Company cannot achieve reduced heat rates at Campbell Units 1 and 2 with the projected expenditures reflected in the IRP, and neither MEC nor the PFD identified a single expenditure reduction that would inhibit the Company's ability to achieve its projected heat rates.[8] The PFD's criticism that Company witness Norman J. Kapala "acknowledged that no documents support the company's revised assumptions" on heat rate values is not a basis to conclude that the assumptions were invalid. PFD, page 194. The PFD ignores Mr. Kapala's testimony that a team put together the data for the Company's heat rate forecast (8 TR 1213), and no party showed that projected heat rates were unattainable.

The PFD appears to have also relied on MEC's position (as stated on pages 22 through 23 of MEC's Initial Brief) that the Company front-loaded non-environmental capital investments under a 2023 scenario to cause an unfair upward bias to the cost of a 2023 retirement for Campbell Units 1 and 2. The PFD (page 194) states that "Consumers Energy has presented no cogent reason why the non-environmental capital expense assumptions through 2023 in both the

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[8] MEC also cited the Company's response to a discovery request that was admitted as Exhibit MEC-86, and claims it did not "provide a meaningful explanation" of its projected lower heat rates despite lower projected spending (MEC's Initial Brief, page 40), but it provided no explanation of the alleged shortcomings in the response.

retirement and non-retirement case should differ." The statement does not square with the record. As Mr. Kapala testified, if the Company retired Campbell Units 1 and 2 in 2023 rather than 2031, it would pull forward some planned capital expenditures, but other expenditures would be reduced or eliminated, and even when some capital expenditures were pulled forward under a 2023 retirement scenario, the 2023 retirement scenario would still provide a net $36,810,000 reduction in capital spending at Campbell Units 1 and 2. Mr. Kapala testified regarding the need to pull forward non-environmental capital expenditures under a 2023 retirement scenario at Campbell Units 1 and 2, specifically stating that "[i]f and when the life of any asset that we operate changes, we would reevaluate that spend based on that change in our business plan" (8 TR 1195), and the purpose of this would be to ensure the reliability of units until their retirement date (8 TR 1167-1169, 1194). Mr. Kapala testified during re-direct that the purpose of pulling the non-environmental capital projects forward under a 2023 retirement scenario versus a 2031 retirement scenario would be to align with the Company's outage plan:

> "Q. Mr. Kapala, you were asked some questions regarding pulling forward capital costs at Campbell 1 and 2 under a 2023 retirement scenario versus a 2031 retirement scenario. Could you please explain the purpose of pulling those capital projects forward?
>
> "A. Yes. So the purpose of pulling those projects forward to align with our outage plan, the retirement date change part of that is to review the outage schedule as well as the overall capital projects that are scheduled in the plan for those units." 8 TR 1226 (emphasis added).

Thus, Mr. Kapala did explain why the Company would pull forward non-environmental capital projects under a 2023 retirement scenario versus a 2031 retirement scenario, and also that the overall spending between 2018 and 2023 would <u>decrease</u> as compared to a 2031 retirement. 8 TR 1167. Thus, neither of MEC's arguments had any merit, and the PFD errs in accepting them.

In recommending that the Commission require the Company to provide a "revised analysis to review the potential savings associated with retiring Campbell unit 2," the PFD required that the revised analysis include "a model that reflects the company's assessment of its best replacement plan." PFD, page 194. The PFD made this recommendation after summarizing the modeling differences between Consumers Energy and MEC. PFD, pages 179-193. The Company's modeling associated with the retirement analysis was thorough and complete, and the Commission should not require the Company to perform additional replacement plan modeling at this time.

MEC witness Tyler Comings testified that MEC's modeling results "show that retiring Campbell Unit 2 in 2023 would provide savings to ratepayers." 8 TR 1862. In rebuttal, Company witness Walz narrowed the consideration of MEC's modeling results to capacity prices of 50% and 75% of Cost of New Entry ("CONE") and to Consumers Energy's natural gas prices. 6 TR 514.[9] In this narrowed consideration, MEC's economic results to replace Campbell Unit 2 in 2023 vary from a potential cost savings of between $35 million Net Present Value ("NPV") to $408 million NPV. 6 TR 515; Exhibit A-105 (STW-27), lines 4-5.

MEC's Strategist modeling of a 2023 retirement of Campbell Units 1 and 2 contains two significant errors, which overstate the projected savings for the 2023 retirement of Campbell Unit 2 by $223 million NPV. 6 TR 516. These errors are: (i) MEC failed to update all of the fixed costs in the 2023 retirement sensitivities, and thus overstated the savings for early retirement both for future capital investments and O&M expenses (6 TR 516); and (ii) MEC's

[9] The Consumers Energy natural gas price is the natural gas price 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.

modeling understated the supply-side solar and wind costs to replace Campbell Units 1 and 2 (6 TR 519). After correcting both the failure to update the fixed costs and the understated solar and wind replacement costs, the economic results to replace 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 (Business As Usual, Consumers Energy's gas price, 75% of CONE capacity value), the above corrections to MEC's modeling show that under the PCA, the retirement of Campbell Unit 2 in 2023 would *increase* customer costs by $189 million NPV. 6 TR 521. The modeled economic results of retirement of Campbell Unit 2 in 2023 do not support modifying the PCA to plan for the retirement of Campbell Unit 2 in 2023.

MEC witness Comings also contended that the Company's modeling should have allowed for a "blend of both market purchases and new resource replacement." 8 TR 1835. There are several concerns with MEC's suggestion. 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 Planning Reserve Margin Requirement ("PRMR") in the MISO PRA. See Capacity Demonstration and Requirements for Planning Years 2022 through 2023 and 2023 through 2024, 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.

In addition, available generating resources within LRZ7 must meet a Local Clearing Requirement ("LCR"), which is established by MISO. 6 TR 476. The LCR represents the minimum amount of generating resources that must be located in each resource planning zone to maintain a loss of load expectation of not more than one day in ten years. 6 TR 476-477. LCR considerations preclude planning to purchase all capacity necessary to meet the PRMR from other zones. 6 TR 477. Recent and projected retirements of coal-fueled units throughout the MISO region have also created uncertainty surrounding reliance on market purchases going forward. 6 TR 476.

Relying on unspecified market purchases of Zonal Resource Credits ("ZRCs") also creates a risk of 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, and could be incurred by customers for a contract term length of up to 25 years. 6 TR 526. MEC did not analyze the cost impact of this considerable risk to customers, and thus did not fully consider the economics of using market purchases in support of the retirement of the Campbell units in 2023. 6 TR 527. It would not be reasonable for the Company to rely on market purchases, including bilateral contracts, as a replacement resource for the Campbell units in 2023.

While not explicitly stated in the PFD, the PFD appears to recommend that the Company perform a fully optimized model simulation for the early retirement of Campbell Unit 2 in addition to Karn Units 1 and 2. But because of several non-modeling and non-economic reasons - including supply portfolio balance, customer rate impact, potential for costly capacity purchases, loss of efficiency in operating Campbell Units 1 and 2 together, and activities necessary to isolate Campbell Units 1 and 2 common facilities - the Company's IRP modeling did not evaluate alternative build plans to fill capacity needs created by the early retirement of more than two of the Medium 4 units. 6 TR 250, 529-530; 8 TR 1171-1172. Thus, the Company did not perform a fully optimized model simulation for the early retirement of more than two of the Medium 4 coal units. 6 TR 530.

Together with the non-economic and non-modeling reasons, the economic justification for early retirement of *any* of the Medium 4 units is not compelling because results did not significantly favor continued operation or retirement. 7 TR 886. The possible savings or costs associated with early retirement of the Medium 4 as compared to the present value of meeting customer energy and capacity needs over the planning period results in a shift in costs of less than plus or minus 1.25%. 7 TR 887. This shift in costs is insignificant because there are many other assumed variables that could easily shift customer costs by this amount over the planning period. 7 TR 887. And the unfavorable economics associated with retiring Campbell Units 1 and 2 in 2023 as presented in the Company's modeling (see 7 TR 949, Figure 1) would only worsen if the Campbell units were retired in addition to Karn Units 1 and 2. 7 TR 952. The lowest cost resources have already been consumed to replace Karn Units 1 and 2 in 2023, and additional capacity required by also retiring any of the Campbell units would come from higher cost resources. 7 TR 952. Given the lack of compelling results related to retiring just two of the Medium 4 units, and the worsening economic results associated with also retiring Campbell Unit 2 in 2023, a fully optimized model simulation for retiring Campbell Unit 2 in addition to Karn Units 1 and 2 is unnecessary at this time.

b. <u>The PFD's Recommendation For A Revised Retirement Analysis Should Be Rejected To The Extent It Calls For Such An Analysis To Be Presented Outside Of An IRP Proceeding</u>

Because the PFD found that "critical assumptions underlying the company's modeling are not well-supported," the PFD recommended "that the Commission call for a revised analysis to review the potential savings associated with retiring Campbell unit 2, with updated and documented heat rate assumptions, with parallel non-environmental capital spending, and with a model that reflects the company's assessment of it best replacement plan." PFD, pages 194-195. The PFD did not recommend a deadline for this analysis but noted that the Company could present one "in a future rate case or IRP case." While the Company will consider the economics of the continued operation of Campbell Unit 2 in future IRP proceedings, the Company opposes the PFD's recommendation to the extent that it calls for an analysis to be performed in a rate case or on a stand-alone basis, because it would be needlessly burdensome and counterproductive.

The Commission required the Company to present the Medium 4 Retirement Analysis as part of an IRP proceeding after parties raised issues related to the potential retirement of the Medium 4 in the Company's electric rate case, Case No. U-18322. See MPSC Case No. U-18322, March 29, 2018 Order, page 25. An IRP proceeding is the appropriate place to present such a retirement analysis because it provides a holistic view of the Company's capacity resource portfolio and potential capacity replacement options. It would require extensive modeling and development to appropriately re-consider the economics of operating Campbell Unit 2 and the parameters recommended by the PFD, which include an analysis of the Company's "best replacement plan." If the Company presented analysis in a rate case or a stand-alone case, it would effectively require the Company to litigate issues germane to IRP proceedings, such as the appropriateness of certain resource plans, outside an IRP proceeding. This result would be unreasonably burdensome. It would also undermine the usefulness of such an analysis if it were filed near the conclusion of this IRP because the underlying assumptions will have changed little, if at all, since the Medium 4 Retirement Analysis presented in this case.[10]

As a reasonable alternative to conducting a new or revised analysis in a rate case or stand-alone case, the Company would agree to assess the potential for the early retirement of Campbell Unit 2 in its next IRP. If the Commission approves the PCA, as proposed by the Company, the Company would agree to file its next IRP within three years from the filing of this case. 6 TR 271. A retirement analysis provided on such a filing date could allow for the meaningful consideration of mid-2020s retirement dates for Campbell Unit 2.[11]

3. Competitive Bidding And Determination Of 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. Thus, in accordance with MCL 460.6t, the Company's IRP assessed its existing and future capacity resource portfolio considering the capacity requirements of the Company's customers through 2040. This assessment not only included generation resources owned by the Company but also the Company's 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. The Company proposes using a competitive bidding process to determine avoided costs. This methodology provides the most accurate representation of the costs that the

[10] This proceeding could extend beyond June of 2019 if the Company's IRP is denied and the Company files a revised IRP pursuant to MCL 460.6t(9).

[11] However, if the Company's IRP is modified, the Company reserves the right to file its next IRP consistent with the five-year schedule established pursuant to MCL 460.6t(20). 6 TR 271.

Company avoids by purchasing from a QF, provides a reasonable means for the acquisition of capacity, and provides customers with the benefit of competitively priced energy and capacity.

As discussed in the PFD, the parties to this proceeding were "generally laudatory" of the Company's proposed use of competitive solicitations. PFD, page 196. Despite the overall support of the parties, the PFD concluded that Consumers Energy has not shown that its current plan to acquire capacity through competitive bidding is reasonable and prudent. PFD, page 202.

a. <u>The PFD Erred In Failing To Approve The Use Of Competitive Bidding To Address All Future Capacity Needs</u>

The Company's competitive bidding proposal represents a shift in Consumers Energy's historical approach to acquiring new supply-side resources. To capitalize on declining cost curves and achieve maximum flexibility, Consumers Energy is proposing to add capacity through smaller, more modular solar projects over a course of years, as opposed to adding large electric generation facilities powered by coal or natural gas. 8 TR 1249. The PFD agreed with this proposal and recommended adopting the Company's plan to acquire solar generation. See PFD, page 169-173.

While recommending the Company's plan to acquire solar generation, the PFD did not provide a means to acquire the future generation because it determined that the proposed plan to acquire capacity through competitive bidding was not reasonable and prudent.[12] PFD, page 202. The PFD contends that the Company's competitive bidding proposal "create[s] a potential advantage for the utility and/or its affiliates," (PFD, page 202), Consumers Energy disagrees. Any affiliate participation in a Company solicitation would require approval by the Federal

[12] It should be noted that on page 297, the PFD indicated that "[a]s discussed in Section VII above, beginning at page 195, Consumers Energy's proposed competitive solicitation is a reasonable means of acquiring capacity, but requires Commission oversight or additional rulemaking protections to ensure that the competitive solicitations are fair and transparent."

Energy Regulatory Commission ("FERC") and would require compliance with the Commission's Code of Conduct. 8 TR 1285. Moreover, by adopting a competitive bidding process, the costs and risks of all submitted proposals are compared against each other, equitable consideration is given to all bidding parties, and 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.

(i.) <u>The PFD Erred In Failing To Find The Company's Competitive Bidding Process Fair And Transparent</u>

The PFD reasoned that Consumers Energy's competitive bidding proposal "lacks sufficient safeguards to ensure ratepayer interests are protected." PFD, page 202. The record does not support that reasoning, and Consumers Energy supports the use of a fair and transparent competitive solicitation process for procuring future generation resources.

The competitive bidding process will be blind to the Company and evaluation of the proposals received will be facilitated by a third party. 8 TR 1291. For the initial solicitations undertaken by the Company, due to the complexity of comparing various technologies and costs, the Company proposes using 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) illustrates the procedure that the Company will use to prepare, issue, evaluate, select, and obtain approval of the projects awarded through each competitive solicitation. That process will prevent self-dealing by the Company.

During the preparation phase, the Company will define the variables of the competitive solicitation. This is based on the capacity need and type of technology that will be included in the competitive solicitation, which were predetermined in the more-recent IRP proceeding. 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 identifying the variables, 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. The PFD took exception to this part of the process, reasoning that "the company should be required to obtain the advance approval of the Commission for the solicitation criteria." PFD, page 205. 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. As evident from the generating units approved through the Company's RE Plan and its reverse capacity solicitations, the Company has successfully conducted competitive solicitations in the past and negotiated mutually agreeable contracts with independent power producers to the benefit of customers. See, e.g., Case No. U-15805; See also, e.g., MPSC Case No. U-18194, January 12, 2017 Order Approving Settlement Agreement. Moreover, the 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 as the Commission will have the ability to review the process before any contract is approved.

After the preparation phase, the Independent Evaluator is responsible for the solicitation phase. The Independent Evaluator will publicly issue the competitive solicitation, including all evaluation criteria, to potential respondents. The maximum term length of the PPA will 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 will field any questions asked by responding parties. 8 TR 1287. This process will be FERC compliant, which means that it will be is transparent, and all questions and responses will be made public to all respondents. 8 TR 1284, 1287. 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.

After the solicitation phase, the Independent Evaluator will run the evaluation phase. During this phase, the Independent Evaluator will develop a short list of recommended projects is developed and will not be in contact with 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. This allows 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 a variety of proposals to be considered in order to determine which option, if any, is the most reasonable and prudent choice for customers. Based on the criteria identified, the list of recommended projects will be ranked from best to worst by the Independent Evaluator. 8 TR 1288.

Once the Company has received the redacted shortlist of recommended projects from the Independent Evaluator, the Company select the project. 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 project's net cost (adjusted by applicable value-added characteristics) and the commodity volumes. 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 all solicitations will be open to any QF technology up to 20 MW in size regardless of the 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. Once the applicable contractual documents have been executed and signed, all selected project information will be submitted to the MPSC for approval.

In reviewing the Company's proposal, the PFD determined that in the absence of advance approval of all competitive solicitations, the Commission should "establish greater advance protections to ensure both the fairness and transparency of the process and ensure that the results reflect a competitive process." PFD, page 205. In order to demonstrate the Company's desire to ensure a fair and transparent competitive bidding process, Consumers Energy agrees to the following procedures for any competitive solicitation undertaken:

- Independent Evaluator : In the implementation of the Company's PCA, the Company will utilize an Independent Evaluator during the competitive solicitation of PPAs and the generating facilities that the Company may ultimately own, in the manner proposed by Company witness Keith G. Troyer at 8 TR 1285-1289 and Exhibit A-107 (KGT-4);

- To the extent applicable, Consumers Energy shall use the RFP parameters included in the 2008 *Guidelines for Competitive Request for Proposal for Renewable and Advanced Cleaner Energy*, as adopted in Attachment D of the Commission's

December 4, 2008 Temporary Order in Case No. U-15800 and proposed by SEIA in its Initial Brief;

- Timely Issuance of RFP through Public Notice: The issuance of an RFP will be made through public notice to ensure parties interested in responding have an opportunity to learn of it; and

- Terms of Contract Provided in RFP: In accordance with MCL 460.6t(6), Consumers Energy shall provide the terms of the contract in their RFP. Consumers Energy may accomplish this by developing standard form contracts along with credit terms and instruments to be included in the RFP.

These procedures will ensure that the Company's competitive bidding process is fair and transparent.

(ii.) <u>The PFD Failed To Recognize The IRP's Role In Determining The Technology Selection And Acquisition Structure During The Competitive Bidding Process</u>

Under the preparation phase of the competitive solicitation process, the Company defines the variables of the solicitation – this includes the technology selection and the acquisition structure. The PFD raised concerns about the Company's role in the preparation phase of the competitive solicitation. These concerns are unwarranted.

The PFD contends that "Consumers Energy has led the parties to believe that it will primarily pursue solar energy in its solicitations, but it has not committed to doing that, since its specific proposal is that it will decide on 'the technologies that are most reasonable to procure,' in advance of each solicitation." PFD, page 202. This assertion is inaccurate. The Company's IRP proceedings will determine the technology sought through competitive solicitations. In this proceeding, the Company's PCA proposes to fill its 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 as early as 2022. 7 TR 910. The Company has proposed that a Commission-approved IRP would determine the technology and capacity need for each year. Thus, the competitive solicitations undertaken after this IRP will be for solar resources. However, each future IRP will examine the most reasonable and prudent generation to procure, which means that things may change—but only after the Commission issues an order approving a future IRP or an amended IRP. Company witness Troyer testified:

> "In preparation of future IRP filings, the Company will determine if it has a need for new generation capacity 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). Energy waste reduction measures (energy efficiency, demand response, etc.) and energy storage would be evaluated 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." 8 TR 1251.

The PFD further contends that all technologies should be able to participate in the competitive solicitations. PFD, page 204. The Company agrees with respect to QFs 20 MWs and below—under PURPA, any technology may participate in the competitive bid, and the Company has included this point in its proposal. But such reasoning should not apply to all projects, because it would render the IRP meritless. During the Company's IRP case, the Commission would pre-determine Consumers Energy's capacity need. The Commission will also determine the type of technology that will be included in the competitive solicitation based on economics, which in this IRP is solar. Based on these findings, certain variables will be fixed in the Company's competitive solicitation, such as the energy payments, and certain variables of the competitive solicitation will be available to bid on by the respondents, such as capacity payments. 8 TR 1285.

Opening competitive solicitations to all technologies removes all managerial discretion from Consumers Energy. The Company does not, for instance, desire to contract with any new coal units. Yet the PFD would require Consumers Energy to allow such units to bid. Opening the solicitations up to all technologies would also add additional administrative costs to the process. 8 TR 1284. More importantly, this could cause unnecessary delays in implementation because of the complexity involved in comparing various technologies, costs, and values. 8 TR 1284. In order to appropriately compare the different proposals, the net cost of a resource needs to be determined. The net cost is especially important when comparing different technologies. 8 TR 1291. While the Company believes this will be manageable for the requested technology under each solicitation and any QF technology up to 20 MW (as necessary under PURPA), opening the solicitations to all technologies of all sizes would be unduly burdensome – especially on an annual basis.

The PFD similarly criticizes the Company for not explicitly agreeing to pursue potential PPAs through its proposed competitive solicitations. PFD, page 202. The PFD commented that "Consumers Energy has led the parties to believe it will pursue potential PPAs, but its actual proposal allows it to limit its solicitations to projects that the company will ultimately own. The company's plan as described does not commit to include PPAs in the solicitations." PFD, page 202. This is inaccurate. The PCA's 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. As discussed below, the Company proposed the inclusion of an FCM on PPAs entered into after the effective date of Act 341. See MCL 460.6t(15). An FCM allows for competitive bidding on all future capacity resources to be effective by removing the disincentive for the Company to enter into PPAs that the ALJ expressed concern about. As Company witness Michael A. Torrey explained, 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. However, 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.

Consumers Energy agrees that the 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. However, the Company does not currently anticipate the need to limit the ownership structure of the proposals received. See Exhibit SEIA-15 (KLM-15). Further, the Company discussed why it believes that different acquisition structures would be contemplated in the solicitation. To that point, Company witness Troyer testified that the Company's intention to limit the acquisition structure is based on its workforce limitations and is not an effort to prohibit opportunities. 8 TR 1291. The Company included a range of possibilities as an option because "if the Company has executed numerous development asset acquisition proposals and is constrained in its available construction resources, it may not be possible to enter into another development asset acquisition for a number of years until the Company's capacity to accommodate additional development asset acquisition projects is restored." Exhibit SEIA-15 (KLM-15). Thus, contrary to the PFD's contention, the Company explained that it included a range of possibilities because of its belief that it may not be able to enter into a number of development asset acquisitions – not due to concerns regarding PPAs.

(iii.) The PFD Failed To Recognize The Reasonableness Of Commencing 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. 8 TR 1281. 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.

The PFD reasoned that "[g]iven that the company's proposal is to begin to acquire capacity above what is strictly required to meet its planning reserve through annual or periodic solicitations, and build up to the time of plant retirements, there appears to be time available to ensure the competitive process is fair and reasonable. The PFD does not perceive any benefit to providing for a bid process to move forward that may well appear unfair down the road, after the results are revealed." PFD, page 205. This recommendation conflicts with the other decisions made in the PFD and ignores the benefits of conducting annual solicitations.

The PFD makes several recommendations on items that conflict with the determination that there is time to make the competitive bidding process reasonable. The PFD indicated that Consumers Energy's plan to acquire solar generation, with flexibility to meet changed conditions, to be reasonable. PFD, page 296. Under this plan, the Company would issue solicitations for 300 MW of solar resources in 2019, 300 MW of solar in 2020, and 500 MW of solar in 2021 to meet its solar glide path for Planning Years 2022, 2023, and 2024, respectively. 8 TR 1305; see Exhibit A-106. While deeming this plan to acquire solar generation reasonable on the one hand, the PFD's recommendation to delay competitive bidding does not allow implementation of this plan. Nowhere in the determination that there is time to delay competitive solicitations does the PFD address the impact of delaying the proposed solar glide path. The PFD also found that the Company's proposal to set PURPA avoided costs on the basis of competitive solicitations to be reasonable. PFD, page 298. Delaying competitive bidding would not provide a means to set avoided costs. While delaying competitive bidding to provide "safeguards to ensure ratepayer interests are protected" (PFD, page 202), the PFD did not address the impact this could have on customers. By delaying competitive bidding, customers could be responsible for PURPA-based PPAs at costs higher that the Company's avoided cost in the amount of approximately $263.3 million annually for the life of the agreements.[13] 8 TR 1248.

In addition to not considering the potential impact of delaying competitive bidding on customers, the PFD also dismisses the fact that the Company has followed a similar competitive bidding process to the one proposed – absent an Independent Evaluator – for the past 10 years. As evidenced from the generating units approved through the Company's RE Plan, and the competitive solicitations undertaken in accordance with the RE Plan, the Company has successfully conducted competitive solicitations in the past and negotiated mutually agreeable contracts with independent power producers to the benefit of customers. See, e.g., MPSC Case No. U-15805. And projects selected as part of the solicitation will be filed for Commission approval along with a description of the solicitation process. 8 TR 1290. Commission review of the projects and the solicitation process will ensure that the actions taken are reasonable and fair

[13] This amount is based on projects that have requested interconnection from May 31, 2017 through May 31, 2018. Since May 31, 2018, the number of requests for interconnection have increased which would result in an increase in costs.

to all stakeholders. For this reason, the Commission should approve Consumers Energy's proposed competitive solicitation process.

b. <u>The PFD Failed To Consider The Totality Of The Company's PURPA-Related Proposals</u>

(i.) <u>The PFD Reasonably Recommended Competitive Bidding To Established PURPA Avoided Costs</u>

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 Natural Gas Combustion Turbine ("NGCT") proxy unit and energy payments made to QFs were based on actual or forecasted LMP plus an Investment Cost Attributable to Energy ("ICE") or the variable cost of a Natural Gas Combined Cycle ("NGCC") proxy unit plus an ICE. MPSC Case No. U-18090, May 31, 2017 Order, pages 5-6.

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 Case No. U-20165, October 5, 2018 Order, pages 20-21 (footnote omitted).

Therefore, the Company requests the Commission's approval to update the methodology and calculations for avoided costs as part of this IRP. The PFD also recommends resetting the avoided cost methodology. See PFD, page 298.

In setting avoided costs, the Company proposes to use two methodologies for determining the Company's avoided cost rates - depending on whether 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.

(a.) <u>The PFD Erred In Determining The Company's Capacity Position</u>

Essential to the determination of the avoided cost rate available to a QF is the Company's capacity position. In accordance with the Commission's November 21, 2017 and February 22, 2018 Orders, in Case No. U-18090, the Company is relieved of its obligation to pay the full capacity avoided cost rate upon demonstrating that it does not have a capacity need over a ten-year period and the Commission's approval of this demonstration.[14] During this IRP proceeding, the Company presented its capacity demonstration and, in future IRPs, the Company

[14] On page 288 through 289 of the PFD, the ALJ recommended modifying the capacity planning horizon to five years.

will provide the results of any competitive solicitation issued prior to the IRP filing. This is consistent with the purpose of an IRP, which 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.

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; and (x) economic parameters such as the discount rate and fixed charge rate. 6 TR 432-435.

Company witness Clark provided the Company's capacity position. 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 forecasts a surplus of capacity from 2019 through 2029. 7 TR 878. The first capacity shortfall of approximately 1,300 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. This determination was based on a number of assumptions that included: (i) retirement dates for Campbell Units 1 and 2, Karn Units 1 and 2, and Karn Units 3 and 4 which occur during MISO Planning Year 2030 through 2031; (ii) continued operation of the Jackson and 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; (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 approved in the RE Plan; and (viii) the Amendment No. 2 to the T.E.S Filer City Station Limited Partnership ("Filer City") 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.

During the development of the IRP, the Company's Baseline Capacity Position was further adjusted as follows: (i) 150 MW of PURPA 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 FERC[15]; (iii) the planned retirement of Campbell Unit 3

[15] 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. The cancellation of Amendment No. 2, as described above, will not have a material

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.

The PFD did not discuss the Company's capacity position based on its Baseline Capacity Position. Discounting the modeling undertaken, and failing to address its reasonableness, the PFD determined that the Company has a capacity need simply because the Company is procuring capacity in the future. PFD, page 288. Under its Baseline Capacity Position, Consumers Energy continues to have a surplus of capacity until a persistent need occurs in the year 2030. 7 TR 880. Based on the Company's modeling, absent moving forward with its PCA, the Company does not have a persistent need for capacity. Thus, if looking at the Company's capacity position over the next 10-year period, as was previously approved by the Commission in Case No. U-18090, or over the next five years as recommended in this case, Consumers Energy does not need to obtain capacity. Because the Company does not currently need capacity, it does not have a capacity position under the Commission's previous determination. See MPSC Case No. U-18090, May 31, 2017 Opinion and Order, page 19.

The PFD's capacity need recommendation seems to conflict with other portions of the PFD that recognized the Company was obtaining surplus capacity. In recommending delaying competitive solicitations under the PCA, the PFD acknowledged that these solicitations were for additional capacity, "[g]iven that the company's proposal is to begin to acquire capacity above what is strictly required to meet its planning reserve…." PFD, page 205. The PFD also

impact on the Company's PCA. Exhibit A-99 (TPC-7) reflects the Company's capacity position without the capacity provided by the converted Filer City Plant.

addressed concerns that "Consumers Energy's IRP builds in a capacity surplus that is not necessary." PFD, page 172. In reviewing these arguments, which were related to the Company's proposed solar glide path under the PCA, the PFD determined that "not find a basis to reject the company's plan due to the surpluses associated with the solar ramp-up, given the flexibility built into the company's plan." PFD, page 173. Because the PFD recognizes that the Company was obtaining surplus capacity, it should not also determine that the Company has a capacity position.

The PFD's recommendation centered around the fact that the Company is planning to acquire long-term capacity. PFD, page 289. The Commission should reject such reasoning because it would 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. 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 ("CON") process. 8 TR 1483. The ramifications of the PFD's recommendation would be to penalize the Company for not building a large baseload generation. This is especially true considering the Commission's Order in Case No. U-18091, DTE Electric Company's ("DTE Electric") avoided cost proceeding, where the Commission recognized that DTE Electric's capacity need must be reexamined in light of the approval of a CON for 1,100 MW of new generation to be built in the future. MPSC Case No. U-18091, December 20, 2018 Order on Rehearing and Remand, page 14. Unlike building a natural gas plant, Consumers Energy is unable to ramp up EWR, DR, and CVR, and build 5.1 GW 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. Under the PFD's reasoning, the very nature of the Company's solar glide path would determine that the Company has an extended capacity position as it is gradually acquiring long-term surplus capacity. This penalizes the Company for proposing a plan that exploits the cost benefits of customer-side programs and adding incremental capacity on a yearly basis. Therefore, the Commission should find that the Company presently has no capacity need.

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-fueled, 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.

(b.) <u>The PFD Agreed With The Company's Full Avoided Cost Eligibility Proposal</u>

Regardless of the Company's capacity position, as previously discussed above, Consumers Energy is proposing utilization of a competitive bidding methodology to select any new supply-side capacity resources. Competitive solicitations would be undertaken annually.

8 TR 1281. QFs of any technology up to 20 MW in size will be eligible to participate in these solicitations. 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. For any remaining capacity need, QFs could fill the remaining capacity need at the avoided cost rate.

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.

The PFD agreed with the Company's proposal to establish avoided costs through the competitive bidding process. See PFD, page 282. While agreeing to the Company's proposal, the PFD additionally found that SEIA's concerns regarding application of the specific attributes of technologies (see 18 CFR 292.304(e)) should be addressed through rulemaking or Commission oversight. See PFD, page 282. The Company's competitive bidding process is fair and transparent, and as discussed above, the Company is willing to agree to further safeguards to ensure its reasonableness. Through this competitive bidding process, the factors can be considered by the Independent Evaluator in reviewing the proposals and the Commission will have an opportunity to review the project selections. This provides the Commission with oversight over the competitive bidding process. Therefore, the Commission should approve Consumers Energy's proposal to establish full avoided costs through competitive bidding.

(c.) The PFD Did Not Make A Recommendation on Consumers Energy's Market-Based Avoided Cost Eligibility Proposal

While a utility is required to purchase energy and capacity from a QF, the rate charged must be at the utility's avoided costs. 18 CFR 292.303(a). When a utility does not need capacity, then it is appropriate for the avoided capacity rate to be lowered to reflect the utility's avoided costs. 18 CFR 292.304(a)(2). It would also be appropriate to ensure that the energy rate paid is consistent with market rates.

In this proceeding, the Company proposed to change the capacity and energy avoided cost rate to market rates for new contracts with QFs based on the Company's capacity need. 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, then no further capacity need exists beyond the capacity to be procured through the approved IRP. At that time, the capacity avoided cost for QFs during the five-year period will be set at PRA rates. 8 TR 1253.

The PCA also proposes changes to the avoided cost 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 contract. 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. 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 PFD did not make any recommendations regarding the Company's proposal to lower avoided costs to market rates when Consumers Energy has no capacity need and the Company requests that the Commission approve its proposal.

(d.) <u>Summary</u>

Consumers Energy respectfully requests that the Commission approve the Company's proposed competitive bidding methodology for determining avoided cost rates, for determining and addressing the Company's capacity position pursuant to PURPA, and for establishing market-based avoided cost rates in the absence of the Company having a capacity position. 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.

	Energy Rate Option 1	**Energy Rate Option 2**	**Capacity Rate**
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 above, 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.

(ii.) <u>The PFD Erred In Not Properly Considering The Company's Renewable Energy Credit Proposal</u>

MCL 460.6t directs the Company to consider renewable energy supply as part of its IRP cases. Since renewable energy is to be considered as part of the IRP, it is necessary for the Renewable Energy Credits ("RECs") to be included as part of the competitive-bid. 8 TR 1292. Previously, in Case No. U-18090, the Commission discussed the treatment of RECs for new PURPA agreements. In its May 31, 2017 Opinion and Order, the Commission noted that Environmental Law & Policy Center ("ELPC"), Great Lakes Renewable Energy Association ("GLREA"), and Independent Power Producers Coalition of Michigan ("IPPC") each objected to assigning RECs to the utility. In that Opinion and Order, the Commission summarized these parties positions as follows, "…this issue was addressed by the FERC in *Windham Solar LLC and Allco Finance Ltd*, 156 FERC P61,042, ¶ 4 (2016) (*Windham Solar*). According to ELPC, in *Windham Solar,* the FERC held that PURPA contracts are compensation for energy and capacity only, and a state commission cannot assign RECs as part of that contract." MPSC Case No. U-18090, May 31, 2017 Opinion and Order, page 25. Ultimately, the Commission found that it "…agrees with IPPC, ELPC, and GLREA's interpretation of *Windham Solar* concerning the ownership of RECs, thus, the amounts paid for energy and capacity do not include compensation for RECs. Accordingly, the QF may sell the RECs to the host utility or otherwise disposed of them at the QF's option." *Id.* at 26. Presumably based on the Commission's Order in Case No. U-18090, and *Windham Solar*, the PFD reasoned that it "does not appear that PURPA permits the Commission to require all solicitations for renewable energy to transfer RECs." PFD, page 292. Based on this premise, the PFD indicated that the Company's proposal to reduce fixed energy payments to subtract the value of RECs does not conform to PURPA's requirements. But Consumers Energy is not arguing that it is entitled to the RECs generated.

Instead, the Company maintains that the energy rate a developer is paid should be based on the energy market.

The competitive solicitation process will 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, 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.

(iii.) <u>The PFD Erred In Finding That The Standard Offer Tariff Should Be Available For Projects Under 2 MW</u>

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.

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. 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.

PFD determined that the Standard Offer Tariff should be available to QFs up to 2 MW in size arguing that the Company failed to support its proposal when arguing that QFs proposing projects of 2 MW are sufficiently sophisticated. This reasoning fails to take into consideration the size of the project. PFD, pages 282-287. FERC regulations require the establishment of Standard Offer rates for utility purchases from QFs with a design capacity of 100 kW or less. 18 CFR 292.304(c)(1). The threshold of the Standard Offer Tariff was set to provide a standard process for customers – not developers. As previously indicated by the Commission, "renewable energy projects are typically classified by size and complexity. A Category 1 project is an inverter based project of 20 kilowatts (kW) or less that uses equipment certified by a nationally recognized testing laboratory to IEEE 1547.1 testing standards; Category 2 is greater than 20 kW to 150 kW and projects less than or equal to 20 kW that do not meet the criteria for Category 1 projects; Category 3 is greater than 150 kW to 550 kW; Category 4 is greater than 550 kW to

2 megawatts (MW); and Category 5 is above 2 MW." See MPSC Case No. U-15919, December 20, 2012 Order Approving Procedures, Agreements, and Forms, page 2, footnote 2. 100 kW is typically the size necessary to serve a commercial property – such as a manufacturing facility or a large office building. See MPSC October 15, 2018 Distributed Generation Program Report for Calendar Year 2017, page 2, (Distributed Generation projects are grouped into size categories with differing billing, metering and interconnection requirements. Category 2 projects (20 kW up to 150 kW) are typically for commercial, industrial, or institutional customers.)[16] It is based on FERC's Standard Offer threshold that the Company recognized 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. It is for that reason the Company's proposed Standard Offer Tariff size aligns with the generator size for customers who are eligible to participate in the Distributed Generation Program.[17] See MCL 460.1173.

The PFD concludes that there is "no logical connection between the size of the standard offer tariff that should be made available under PURPA and the size of the distributed generation program." PFD, page 283. The connection, however, between the Distributed Generation Program and the Standard Offer are clear. These statutory provisions are in place to ensure the availability of renewable energy self-generation projects for customers. The Commission already recognized this when it noted the alignment of DTE Electric's Standard Offer with Michigan's Electric Interconnection and Net Metering Standards. Here, the Commission stated:

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[16] https://www.michigan.gov/documents/mpsc/DG_report_cal__yr_2017_636048_7.pdf

[17] 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.

> "the Commission finds that a 550 kW cap is appropriate given the newly arising circumstances of the NGCC plant approval, for the purpose of maintaining consistency with other Michigan utilities for whom the Commission has set a 550 kW cap, and to align with the project categories defined under Michigan's Electric Interconnection and Net Metering Standards, Mich Admin Code, R 460.601a *et seq*. (Interconnection Standards)." MPSC Case No. U-18091, December 20, 2018 Order on Rehearing and Remand, page 15.

The PFD disregards the Company's contention that the Standard Offer Tariff is intended for small customer-owned distributed generation projects contending that the Standard Offer Tariff approved in Case No. U-18090 was not written for small customer-owned projects. PFD, page 285. But the parties litigated this contract with the knowledge that at the time it was for projects up to 2 MW, which would include sophisticated developers. Further, as drafted, this contract was approved for small customer-owned distributed generation projects as it does not have separate provisions for projects under 150 kw. Moreover, while raising concerns about the positive benefit of having a standard offer tariff in place to reduce transaction costs, (PFD, page 286), this argument overlooks the Company's statutory requirement. MCL 460.6v(4)(e) provides that the Commission shall:

> "[r]equire electric utilities to publish on their websites template contracts for power purchase agreements for qualifying facilities of less than 3 megawatts that need not include terms for either price or duration of the contract. The terms of a template contract published under this subsection are not binding on either an electric utility or a qualifying facility and may be negotiated and altered upon agreement between an electric utility and a qualifying facility."

While the Legislature's decision to require utilities to publish a non-binding template contract on its website for QFs use, it does not specify a certain size for the Company's Standard Offer Tariff. The non-binding template contract should relieve concerns about transaction costs, as a developer of a project 3 MW or less would have the option of utilizing the template contract published on the Company's website.

More importantly, the PFD's recommendation failed to appropriately consider the Commission's recent decisions regarding the Standard Offer Tariff. In Case No. U-18091, DTE Electric's avoided cost proceeding, the Commission indicated that QF eligibility for the Standard Offer should be linked to a utility's capacity need. Specifically, the Commission held that:

> "Because the QF eligibility cap for the Standard Offer is linked to the company's capacity needs, the Commission finds that the two MW Standard Offer cap that was previously approved in the July 31 order is no longer appropriate. The Commission agrees with the Staff's concept of utilizing a range for the Standard Offer cap that varies depending on the amount of capacity needed and when it occurs in the planning horizon. 2 Tr 74-75. The Commission also agrees that it should consider the impact setting a Standard Offer cap will have on a QF, its ability to negotiate with the company for a PURPA contract, and on the goal of PURPA to encourage QF development. *Id*., pp. 73-75, 283; *see*, 16 USC 2611. Further, the Commission continues to disagree with DTE Electric's position that a 100 kW cap is appropriate because the company failed to support its position beyond asserting that it disagreed with any cap higher than the minimum of 100 kW. *Id*., p. 313. Therefore, the Commission finds that a 550 kW cap is appropriate given the newly arising circumstances of the NGCC plant approval, for the purpose of maintaining consistency with other Michigan utilities for whom the Commission has set a 550 kW cap, and to align with the project categories defined under Michigan's Electric Interconnection and Net Metering Standards, Mich Admin Code, R 460.601a *et seq*. (Interconnection Standards)." MPSC Case No. U-18091, December 20, 2018 Order on Rehearing and Remand, pages 14-15.

The Commission made similar findings in its December 20, 2018 Order in Case No. U-18092, December 20, 2018 Order in Case No. U-18093, and December 20, 2018 Order in Case Nos. U-18095/U-18096. In an attempt to distinguish the circumstances from the Commission's recent decisions, the PFD posited that the Commission had already approved a standard offer tariff size of 2 MW for the Company. PFD, page 287. While this is accurate, the PFD's reasoning fails to consider that a standard offer tariff size of 2 MW was previously approved for DTE Electric. See MPSC Case No. U-18091, July 31, 2017 Opinion and Order, page 21. It was not until the MPSC's recent order on rehearing did the Commission determine that the Standard Offer should be linked to a utility's capacity need. As the Company's Baseline Capacity Position shows that Consumers Energy does not have a capacity need, it is reasonable for the Standard Offer Tariff size to be reduced to 150 kW. Therefore, the Commission should approve the Company's Standard Offer Tariff proposal.

(iv.) <u>The PFD Erred In Not Considering The Company's Contract Length Proposal</u>

Under the PCA, the Company proposed the availability of multiple contract lengths to be made available to QFs. The PFD did not address the totality of the Company's proposal.

When entering into a contract at full avoided costs, Consumers Energy proposes that the maximum term length of the PPA should be equivalent to the depreciation schedule of a similar Company-owned asset. Thus, the maximum contract term length will be established in each solicitation to align with the life of the asset. 8 TR 1270. As the Company's IRP has selected solar as the next generating resource, for solar facilities, the Company anticipates soliciting for 25-year PPAs using the competitive solicitation process. 8 TR 1289. This proposed contract length is greater than what was approved by the Commission is Case No. U-18090. The PFD did not make a recommendation regarding the Company's proposed contract term for full avoided cost PPAs.

The Company proposed different contract lengths in a situation where the Company's IRP establishes that it is not in need of capacity. These different contract lengths are based on proposed 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. The PFD did not make a general recommendation regarding the Company's proposed contract terms for PPAs entered into under PURPA when the Company does not need capacity; instead, the PFD focused on one aspect of the Company's proposal, the reasonableness of entering into a five-year contract. PFD, page 291. Here, the PFD determined that entering into a five-year contract, using forecasted LMPs, when the Company does not need capacity is unreasonable. PFD, pages 291, 298.

The Company proposes the adoption of a five-year 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. This is due to shifts in technology and generation fuel prices that affect the market. 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. 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. 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.

In arguing that the Company's proposed contract term is inconsistent with PURPA, the PFD cites two FERC decisions in support. PFD, page 291. These decisions do not stand for the proposition that the use of a five-year contract based on forecasted LMPs, when no capacity is needed, violates PURPA. Instead, the quoted passage from in *Windham Solar* stated, that:

> "The Commission has also held that 'requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation.' The Commission likewise has determined a state regulation to be inconsistent with PURPA and the Commission's PURPA regulations 'to the extent that it offers the competitive solicitation process as the only means by which a QF can obtain long-term avoided cost rates. Accordingly, regardless of whether a QF has participated in a request for proposal, that QF has the right to obtain a legally enforceable contract.'" 156 FERC 61,042, July 21, 2016, paragraphs 4-5.

The Company's proposal allows for the entrance of long-term contracts, whether the QF elects to participate in the competitive solicitation or not, and the Company is even proposing a longer contract term in situations where it does not need capacity. FERC has never declared that a five-year contract length is not appropriate. Instead, the appropriate contract term is an item left to the discretion of the state. Where no capacity need exists, a five-year term is appropriate for a QF desiring to take a rate based on projections.

The Commission's other recent avoided cost orders show a willingness to examine departure from the use of 20-year LMP forecasts in contracts – as was originally imposed on Consumers Energy in Case No. U-18090. For instance, in DTE Electric's avoided cost case, Case No. U-18091, the Commission directed the parties to submit evidence in a remand proceeding pertaining to "a fixed energy rate, a variable energy rate, or a combination of a fixed rate followed by a variable energy rate" and also required "an annual energy forecast based on the NGCC plant for at least a 10-year period." The Commission's direction in this case demonstrates a willingness to reconsider its approach to contracts at a forecasted energy rate.

Moreover, in Indiana Michigan Power Company's avoided cost case, Case No. U-18092, the Commission found that an avoided energy rate "based on an LMP forecast over the first five years of the contract period followed by a variable rate based on LMP at the time of delivery is reasonable." MPSC Case No. U-18092, December 20, 2018 Opinion and Order, page 11. The Commission explained that "…the longer period of five years for a fixed rate followed by the variable rates thereafter is consistent with the requirements of PURPA and provides greater certainty for QFs while limiting inherent pricing risk for customers associated with long-term fixed rates and inaccurate forecasts. *See*, 18 CFR 292.304(b)(5)." *Id.* The Company's two-pronged approach for PURPA contracts in the absence of a capacity need follows the same approach.

The following table summarizes the contract lengths that the Company recommends the Commission approve for new QF contracts based on the Company's capacity need, the energy rate, and the capacity rate paid under the contract. Under the Company's Standard Offer Tariff proposal, projects 150 kW or less would be eligible for full avoided costs. Thus, these projects would be eligible for the maximum contract term specified in the solicitation – which for a solar solicitation is 25 years. 8 TR 1270.

	Energy Rate	**Maximum Contract Term**
No Capacity Need	Forecast LMP	5 Years
No Capacity Need	Actual LMP	15 Years
Capacity Need	Competitively Bid	Specified in Solicitation
Capacity Need	Actual LMP	Specified in Solicitation

(v.) <u>The PFD Reasonably Recommended A Five-Year PURPA Capacity Planning Horizon</u>

At page 289, the PFD indicates that the use of a five-year capacity planning horizon is not unreasonable under PURPA. The Company agrees with the use of a five-year capacity demonstration period but notes that 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. 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 a 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.

4. FCM

a. Introduction

The PFD recommends that the Commission reject the Company's request for an FCM or, in fact, any form of a PPA incentive mechanism. As a preliminary matter, it is important to recognize that the principal error of the PFD's reasoning is an error of omission. The PFD failed to recognize and appreciate the ramifications on the other parts of the overall resource plan represented by the PCA if there is no adequate and reasonably structured PPA incentive mechanism included as part of the plan.

Consumers Energy has emphasized from the very beginning of this process that "[e]very part of this plan is interdependent with the other parts." 8 TR 1467. The Company has steadfastly maintained that, unlike other types of MPSC proceedings that may involve a smorgasbord of additive, but otherwise independent issues, an IRP really is an *integrated* plan - precisely as the law intended. Modification of one part of the plan impacts the continuing viability of other parts of the plan.[18] With this understanding, it is inappropriate to recommend changes to any piece without analyzing the specific impact of those changes on all the other pieces of the integrated and interrelated plan to ensure that the entire plan remains viable. In the case of the Company's proposed FCM, the PFD makes no effort to do that.

In particular, the FCM is necessary to preserve the viability of using competitive bidding for all or even a significant percentage of the Company's future capacity procurements. The

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[18] Many of the parties have accused the Company of promoting a take-it-or-leave-it approach to the IRP, and the PFD appears to accept those arguments. But, that is an inaccurate understanding of the Company's point. The Company's position has never been that the Commission must take the Company's plan or leave it. Instead, the Company's position has been that it is risky and potentially very harmful to treat any of the issues in this case in isolation. The PCA "reflects a careful balance of many competing concerns, which taken together as a whole, will ensure the best plan for Michigan . . . ." 8 TR 1467. Any recommended changes will create imbalances that were solved by the Company's plan. If changes in one part are necessary, the entire plan must be adjusted in ways that are carefully thought out – in the whole – to reestablish that original careful and workable balance.

FCM is also necessary if there is a significant possibility that large amounts of the Company's capacity needs will be satisfied by PURPA contracts (even if competitive bidding ultimately plays no role in the negotiation and implementation of those contracts). Private investor-owned utilities such as Consumers Energy require earnings in order to attract adequate equity capital. 8 TR 1473. But, without an incentive mechanism, PPAs have no earning potential. 8 TR 1473. Earnings also support the Company's credit. 7 TR 728. Therefore, deteriorating earnings will also drive away debt capital or at least significantly increase the cost of debt capital. Customers rely on this private debt and equity capital to adequately finance the continuing business operations of the Company and to maintain capital costs at reasonable rates.

Without an FCM, competitive bidding for all future capacity resources no longer works. The Company would need to plan on utility-ownership of a significant majority of all future generation assets in order to protect investor's and customers' interests. Without an FCM, the Company's plan to utilize leaner and more modular capacity procurements also no longer works. The Company would need to plan for a larger, single-solution generating plant to replace retiring capacity in order to avoid a significant open-capacity position that would leave the Company and its customers vulnerable to a figurative "death by a thousand cuts" from a flood of over-market-priced PURPA PPAs.

The PFD offers no indication that it recognizes or understands these implications of rejecting any form of PPA incentive mechanism on the remaining parts of the Company's IRP. The reasoning in the PFD commits a number of errors, many of which relate directly back to this theme of failing to consider what rejection of an FCM means to the viability of other issues discussed in the PFD. The Commission should reject the PFD's recommendation and adopt the FCM proposed by the Company in this case.

b. <u>The PFD Erred In Finding That There Is No Demonstrated Need For An FCM</u>

The PFD concludes that the Company has not demonstrated a need for its proposed FCM and offers three substantive reasons for that conclusion. First, the PFD reasons that the FCM is not needed because the Company's cost of capital, as set in a general rate case, "considers all risks facing the utility, business and financial." PFD, page 243. Second, the PFD reasons that the FCM is not needed because there are "statutory protections" on the recovery of costs paid under approved PPAs. PFD, page 246. Third, the PFD reasons that the FCM is not needed because the Company is not proposing to increase its portfolio of PPA above current levels until 2025 or later. PFD, page 248. There are problems with each of the reasons offered by the PFD, but there is also a problem with the reasoning that the PFD does not recognize or consider.

As the Company pointed out in its Initial Brief, the FCM is needed for two reasons: (i) to incent the Company to voluntarily engage in a clean, lean, and modular procurement plan that exposes Consumers Energy to the risk that a significant proportion – and potentially all – of the Company's future capacity acquisitions would be met through PPAs; and (ii) to fairly incorporate the impacts of imputed debt caused by PPAs so that the costs are visible at the time of procurement and so that there is a built-in vehicle for recovery of those costs. Consumers Energy's Initial Brief, pages 123-125; see also 7 TR 735. The reasons cited by the PFD to explain away the need for an FCM are not responsive to the evidence presented by the Company to explain the dual needs supporting the approval of the FCM.

In general, the PFD views a PPA as creating three types of costs. The PFD recognizes that a PPA creates capacity costs, energy costs, and capital costs.[19] In essence, the PFD takes the

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[19] In order to understand the source of the capital costs, it is necessary to understand that PPAs have similar financial characteristics as long-term debt, but are not recorded on the Company's balance sheet. 7 TR 722. Nevertheless,

position that the Power Supply Cost Recovery ("PSCR") process, backed up by the working capital allowance, all but guarantees recovery of the capacity and energy costs (PFD Reason 2). And, the PFD takes the position that the capital costs are fully incorporated in the capital structure in the Company's rate cases (PFD Reason 1). The PFD's reasoning does not acknowledge that there is significant uncertainty about the cost recovery for the capital costs in rate cases. The PFD's reasoning is premised entirely on the outcome of recent *past* rate cases to support the determination that there is "no evidence . . . that the Commission determined returns on equity have been inadequate...." PFD, page 245. But, past outcomes may not be indicative of future results.

Consumers Energy agrees that recent electric rate case orders from the Commission have included some accommodation to recognize the impact of imputed debt. But, the recognition and cost recovery of the Company's existing imputed debt has been under attack in the Company's rate cases for several years. In the Commission's November 19, 2015 Order in Case No. U-17735, the Commission rejected arguments by Staff and the Attorney General to artificially reduce the Company's 52.48% proposed equity ratio in its capital structure. The Commission rejected the parties' proposal on the basis that the higher ratio was needed to maintain the Company's strong credit in light of the fact that certain credit rating agencies "include securitization debt, <u>power purchase agreements</u>, and benefit obligations as debt when

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financial analysts, including rating agencies, incorporate PPA obligations as "imputed debt" 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. 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. However, that cost is not recovered through the PSCR process or in the Company's working capital allowance. In addition to the Company's extensive testimony about the impact of imputed debt, witnesses for Staff, MEC, and ABATE all expressly acknowledge that PPAs have a real financial impact on utilities as a result of the imputed debt phenomenon. 8 TR 1795, 2137; 9 TR 2715.

calculating debt to equity ratios." MPSC Case No. U-17735, November 19, 2015 Order, page 31 (emphasis added). Some parties once again pushed for a reduction of the Company's equity ratio in Consumers Energy's next electric rate case, Case No. U-17990. By the time the Commission issued its final order in Case No. U-17990 on February 28, 2017, the Company's equity ratio had increased further to 52.87%. MPSC Case No. U-17990, February 28, 2017 Order, page 60. Although the Commission expressed a desire to see the Company's equity ratio begin to return to more balanced levels, the Commission nevertheless approved the Company's proposed equity ratio with instructions for the Company to show a plan to return to a balanced equity ratio within five years. *Id*. at 63-64. The Commission's decision to allow the Company a five-year time horizon within which to bring down its equity ratio appears to have been, at least partly, in recognition of the Company's need to maintain its credit metrics in light of the impact of imputed debt as recommended by the PFD in that case. *Id*. at 62. In Case No. U-18322, Consumers Energy took steps to reduce its equity ratio to 52.64% and articulated a plan to return to a 50% equity ratio within five years in response to the Commission's directive from Case No. U-17990. MPSC Case No. U-18322, March 29, 2018 Order, page 32. Once again, the Commission rebuffed the arguments of several parties who recommended that the Commission artificially move the Company immediately to a 50% equity ratio. Among other issues discussed in the order, the Commission noted testimony by the Company that one of its largest PPAs is set to expire within the five-year horizon and that the Company's "<u>plan to reduce its portfolio of PPAs will enhance its credit metrics, strengthen its credit rating, and benefit customers</u>." MPSC Case No. U-18322, March 29, 2018 Order, pages 33-34 (emphasis added).

From these recent rate case orders, it is clear that the Commission wants the Company to take steps to reduce its equity ratio, but the addition of significant numbers of new PPAs would have the effect of pushing the equity ratio up in future cases, assuming that the Commission intends to continue permitting the Company to recover those costs and maintain its credit metrics. It is not currently clear what the Commission will do with the Company's equity ratio in upcoming rate cases or whether it will continue to accommodate the Company's recovery of those imputed debt costs as part of the capital structure. So, the PFD's observations that recent past rate cases have considered and incorporated all of the Company's business and financial risks, including imputed debt from PPAs, even if true, does not provide a reason why an FCM is unnecessary in this case. One of the reasons for having an FCM is to provide a built-in recovery mechanism for those imputed debt capital costs in the *future*, particularly where the Company could add thousands of megawatts of new PPAs potentially representing 50%, 70%, or even 100% of its capacity portfolio. The future state of the Company's capacity portfolio as envisioned in the Company's PCA simply does not look anything like the Company's capacity portfolio in any of the past rate cases.

The PFD's reasoning also overlooks a second aspect of why an FCM should be approved. The FCM is designed to make the imputed debt costs visible at the time of the capacity procurement. Again, even if one were to agree that recent Commission rate orders have fully considered the Company's existing imputed debt costs associated with its current PPAs and included recovery of those costs in rates, that all occurred after the Company had already entered into those PPAs. The costs would not have been visible to customers, regulators, and other interested parties at the time of the capacity procurement. Unless all the costs associated with a PPA are made visible at the time the procurement decision is made, the full cost of the PPA cannot be adequately considered. This is true even if one assumes, as the PFD does, that all future rate cases will continue to include cost recovery for imputed debt. So, again, the PFD's reasoning is not sufficient to support the conclusion that an FCM is not needed.

Turning to the PFD's second reason for concluding that an FCM is not necessary, the PFD begins with a factually inaccurate claim. The PFD states that cost recovery for PPAs is "fully reconciled through the Act 304 reconciliation process" which provides for "recovery to the dollar" of the costs associated with approved PPAs. But, in making this claim, the PFD overlooks its own discussion from the immediately preceding section of the PFD of one important cost associated with approved PPAs that is not recovered as part of the PSCR process: the capital costs from imputed debt. The PFD points out that many of the Company's PPAs have "regulatory out" clauses and quotes from the "regulatory out" clause in the Company's standard offer tariff approved in MPSC Case No. U-18090, as evidence to support the PFD's conclusion that the Company "has not shown that it has any material risk of not recovering PPA-related costs not recovered through rates." PFD, pages 247-248. But, the Company has not argued that it has any material risk of not recovering PPA-related costs "not recovered through rates." The Company has argued extensively that it has a material risk of not recovering PPA-related costs that *are* recovered through base rates (or not at all). The "regulatory out" clause from the Company's standard offer tariff quoted in the PFD clearly only affords the Company a "regulatory out" if the Company is unable to obtain "complete recovery from its customers of the <u>capacity</u> and <u>energy charges</u>" under a standard offer PPA. PFD, page 247 (emphasis added). There is no "regulatory out" if the Company is unable to obtain complete recovery from its customers of the <u>capital costs</u> caused by the PPA.

Furthermore, the FCM is necessary is to provide the Company an incentive to forego utility ownership of generation, and the related earnings, in favor of a system that could entail procuring most or even all generation through PPAs that provide no earnings. Bare cost recovery alone will not be sufficient to incent the Company to adopt a new model that undermines its ability to achieve earnings. Staff witness Paul Proudfoot articulated the concern very well. He explained that "without a PPA incentive that is high enough for the Company to accept, it may be difficult to expect the Company to enter into thousands of megawatts of PPAs for solar resources if they have a low incentive with little opportunity to earn on those PPAs." 9 TR 2565. The PFD's reasoning regarding the assurance of cost recovery under the PSCR process does not address that reason for needing an FCM.

The PFD also concludes that the Company's request for an FCM is premature because the Company is not proposing to increase its portfolio of PPAs above current levels until 2025 or later. PFD, page 248. The PFD does not consider when the Company would actually need to enter into new PPAs to achieve the solar resource glide path proposed in the PCA. The record establishes that the Company's proposed solar resource glide path is set to begin in 2022 when 300 MW of new solar resources are brought online. 7 TR 910. The Company further proposes to continue its glide path of new solar resources in 2023, 2024, and 2025 by bringing 300 MW, 500 MW, and 500 MW, respectively, online. See Figure 7, 7 TR 908. However, when reviewing the Company's proposal, it is important to understand that the aforementioned dates represent "online" dates (i.e. the date on which a unit is available to generate). To achieve these online dates, the Company must begin its resource acquisition plan much sooner. The Company's proposed acquisition plan, as detailed by Exhibit A-106 (KGT-3), includes annual competitive solicitations for solar resource PPAs beginning in 2019. This means that the Company's obligations under new solar resource PPAs will begin in 2019, not years from now as the PFD suggests.

The PFD also undervalues the amount of capacity that the Company may purchase through new PPAs by 2025. The PFD concludes that the Company does not plan to have added solar capacity equivalent to the Palisades PPA until 2025. PFD, page 248. This conclusion does not consider the amount of capacity that the Company will purchase by 2025. As illustrated by Exhibit A-106 (KGT-3), the Company is proposing to procure 3,100 MW of new solar resources by 2025. Since the Company has indicated it will rely on PPAs to meet this target, particularly in the early years of the PCA (8 TR 1381-1382), the new capacity that the Company will procure through PPAs by 2025 is likely to be significant and will dwarf the capacity provided by the Palisades PPA.

The Company's request for an FCM is not premature in this matter. The Company is proposing to immediately begin procuring a significant amount of new solar resource capacity, which will potentially make the Company more heavily dependent on PPAs than it has at any time previously. The Commission should ignore the PFD's attempt to downplay the significance of the Company's proposed resource acquisition plan.

Contrary to the conclusion reached in the PFD, there are two significant reasons why the Company's proposed FCM is needed. An FCM is needed to incent the Company to voluntarily engage in a clean, lean, and modular procurement plan that exposes Consumers Energy to the risk that potentially all of its future capacity acquisitions would be met through PPAs and to fairly incorporate the impacts of imputed debt caused by PPAs so that the costs are visible at the time of procurement and so that there is a built-in vehicle for recovery of those costs. The reasons offered in the PFD for finding that an FCM is not needed do not address these issues and include factual inaccuracies that render the PFD's conclusions unsound. The Commission should reject the PFD's recommendation of a finding that the FCM is not necessary.

c. The PFD's Criticism Of The Company's Calculation Of The FCM Is Not Supported By The Record

Although the PFD recommends a finding that the FCM is not needed and proposes that the Commission reject an FCM in its entirety, the PFD nevertheless also criticizes the Company's proposed methodology for calculating the FCM. The PFD concludes that the Company's method of calculating the FCM is not appropriate because it "exceeds the calculation performed by S&P," and overstates the cost associated with imputed debt. PFD, page 249. The PFD's criticism and, by extension, its proposed finding that the Company's calculation overstates imputed debt costs is without merit.

The Company was clear in testimony that its proposed FCM calculation was not intended to exactly duplicate the imputed debt calculations performed by S&P. Company witness Srikanth Maddipati testified:

> "[W]hile my methodology most closely aligns with the methodology used by S&P, it is not intended to mimic the methodology for any particular agency or investor. The methodology for calculating off-balance sheet obligations (i.e., imputed debt) varies by agency and by each investor. Furthermore, the impact of off-balance sheet financing by third parties will most likely not incorporate specific parameters from the Company's rate orders. My methodology is intended to calculate the impact of contractual obligations to the Company's financial position. It incorporates inputs from the Company's rate orders, varies by the length of the PPA, and includes only costs that create contractual obligations. It acknowledges the lower risk afforded costs recovered via the existing PSCR mechanism while also conforming to restrictions placed on a potential incentive mechanism as outlined in PA 341." 7 TR 750.

The similarity between the Company's proposed methodology and S&P's imputed debt calculation results from the fact that S&P identifies the most explicit methodology for calculating imputed debt among its rating agency peers. 7 TR 723. Therefore, it provides the most accessible model for constructing a proposed FCM calculation. But, the methodology ultimately used by the Company must attempt to reasonably approximate and account for imputed debt calculations made by a variety of different credit rating agencies and investors. And, in order to provide the proper incentives that serve as the reason for implementing an FCM in the first place, they should be more explicitly tied to the Company's actual rate case outcomes than the calculations made by third-parties might be. Therefore, the PFD's presumption that the Company's FCM methodology is flawed because it might not adhere exactly to the S&P methodology in every respect is misplaced.

In any case, the PFD's criticisms of the Company's methodology do not support the conclusion that the Company's methodology inappropriately inflates the imputed debt cost. The PFD identifies three aspects of the Company's FCM methodology that the PFD claims inappropriately inflate the amount of the Company's proposed FCM. First, the PFD criticized the Company's use of a lower discount rate to calculate the NPV of the cumulative PPA payments. S&P uses a generic 7% discount rate for calculating imputed debt for all utilities whose credit they review. 7 TR 723, 778. But, that discount rate is not tied in any way to Consumers Energy's specific experience. So, Mr. Maddipati applied a discount rate that reflects the actual after-tax overall rate of return for the Company approved in the Company's last rate case. 7 TR 728. At the time of calculating the sample FCM in this case, that was 5.89%. 7 TR 730. Obviously, this discount rate was lower than the generic discount rate used by S&P, which means that it produces a higher NPV than S&P's calculation in this instance. But, there is no legitimate reason to assume that the Company's overall rate of return will be lower than S&P's generic 7% discount rate in all cases. In point of fact, the 5.89% discount rate used in Mr. Maddipati' s example is no longer the approved overall rate of return for the Company, since the Commission has subsequently approved a settlement in the Company's last electric rate case.

See MPSC Case No. U-20134, January 9, 2019 Order Approving Settlement Agreement. Although the Company's settlement in Case No. U-20134 is silent on the specific overall rate of return that resulted from that Order, the briefing of the parties in that case would suggest that the rate has increased above the 5.89% level used in Mr. Maddipati's example, thereby dampening any difference between the result the Company's method would calculate and the result using S&P's generic 7% discount rate.

Second, the PFD criticizes the Company's methodology for not differentiating between capacity and energy payments when calculating the NPV of the PPA. The PFD claims that this inflates the total value of the PPA above the amount that S&P would recognize because S&P only includes capacity payments in its imputed debt calculation. However, the unrefuted testimony in the record demonstrates that is not necessarily true. During cross-examination, counsel for MEC asked Mr. Maddipati specifically about that issue as follows:

> "Q. And then you mentioned that you used all fixed obligations, whereas S&P may try to use capacity payments, depending on disclosure and what information is available. Did I get that right?
>
> "A. Yes.
>
> "Q. And so directionally, that would tend to make their number higher, lower, or no difference than yours?
>
> "A. It would depend. It would depend on whether the capacity payment is greater than the fixed obligation." 7 TR 780.

Further, cross-examination from MEC established that, generally speaking, PPA contracts are structured so that capacity costs included in the agreement are included as fixed obligations. 7 TR 781. So, in many PPAs, the concept of capacity costs and fixed obligations may be synonymous. Finally, MEC's cross-examination asked Mr. Maddipati to think about the distinction between capacity costs and fixed obligations in the context of one of Consumers

Energy's current large PPAs and comment on whether there would be any differences between S&P's imputed cost methodology and the Company's FCM methodology if applied to that PPA. Mr. Maddipati testified that he was not aware of any differences that would result. 7 TR 782. The PFD's presumption that Mr. Maddipati's use of fixed obligations to calculate the NPV of a PPA for purposes of calculating the FCM would necessarily result in a higher FCM is simply unwarranted.[20]

Third, the PFD criticizes Mr. Maddipati's use of a 25% risk factor for calculating the FCM. Whereas, in all of the PFD's other criticisms, the PFD found that Mr. Maddipati's approach was deficient because it *didn't* use the exact inputs that S&P used for its imputed debt calculation, in this case Mr. Maddipati *did* use exactly the risk factor adopted by S&P for Consumers Energy's imputed debt calculation, but the PFD rejected his approach anyway. In this case, the PFD simply deemed the 25% risk factor as "not well supported on this record" because – the PFD concludes – Exhibit A-115 (SM-6) "is not persuasive." Exhibit A-115 (SM-6) is an e-mail from S&P itself stating that S&P uses a 25% risk factor for Consumers Energy when calculating the Company's imputed debt. The PFD appears to challenge the credibility of Exhibit A-115 (SM-6) by referring to it merely as an "e-mail from 'Gabe' at S&P" and claiming that it includes "no details or explanation." PFD, page 251. However, as shown in

[20] The PFD also appears to take issue with whether Mr. Maddipati's original proposal in his direct testimony actually intended to limit the application of the FCM to only the fixed obligations in a PPA. PFD, page 250 ("Mr. Maddipati claimed that he only included 'fixed obligations' under the PPA agreements . . . . Nothing in his earlier testimony had hinted at this distinction."). In his rebuttal testimony, Mr. Maddipati testified that it was his intent to do so. 7 TR 749-750. Mr. Maddipati essentially acknowledges that his direct testimony may not have been clear on this point, as he testified that he "clarified" this issue in a discovery response to Staff. 7 TR 749. Regardless, even if Mr. Maddipati's direct testimony had not excluded non-fixed obligations from the calculation of his FCM, that would not be an appropriate reason to recommend rejection of the FCM. At worst, the rebuttal testimony corrects an oversight in Mr. Maddipati's direct testimony, which he has the right to do. Even if Mr. Maddipati had steadfastly testified that all costs should be included in the calculation of the NPV of the PPA for purposes of the FCM, the Commission need not reject the proposal for that reason. If the Commission believed it was more appropriate to include only the fixed obligations, it is free to say so as part of its Orders in this case. It is unclear why the PFD seems to suggest that this sequence of events somehow serves as an independent reason to reject the FCM.

Exhibit A-115 (SM-6) itself, “Gabe” is in fact Gabe Grosberg, Director of North American Regulated Utilities Global Infrastructure Ratings for S&P Global Ratings in New York. Even more compelling, Mr. Grosberg is listed among the “Primary Credit Analysts” who contributed to S&P’s November 19, 2013 circular entitled “Key Credit Factors For The Regulated Utilities Industry.” That S&P circular is included in the record in this case as Staff Exhibit S-15.1 (see page 45 of the exhibit). Exhibit S-15.1 is a more current version of the outdated 2007 S&P circular that Staff witness Harlow relied upon to argue that the risk factor should be lower than 25%. 9 TR 2717. Whereas the outdated circular indicated that a lower risk factor might be appropriate for a “legislatively created” cost recovery mechanism and a higher factor for a “regulator established” mechanism (9 TR 2717), the more current S&P circular uses language suggesting that the division is not that clear. The 2013 S&P circular states that “[i]f a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed.” Exhibit S-15.1, page 58. The 2013 circular then also states that a lower risk factor “may” be appropriate for a “[s]pecialized, legislatively created cost recovery mechanism . . . depending on the legislative provisions for cost recovery and the supply function borne by the utility.” Exhibit S-15.1, page 58. The 2013 circular offers no greater clarification on what might constitute a “specialized” legislative mechanism or what particular types of legislative provisions and supply functions of the utility the lower risk factor “depends” upon. However, the most reasonable means of understanding the precise interpretation and application of these criteria would be to find out how S&P interprets and applies them. That is what Mr. Maddipati did. The PFD’s recommendation to reject the 25% risk factor as “not well supported on this record” is explicitly rejects the best evidence in the record regarding the proper interpretation and application of S&P’s risk-factor criteria and is without merit.

The PFD then points to a 2016 Public Service Commission of Wisconsin ("PSCW") decision as support for the proposition that other states that explicitly consider imputed debt in ratemaking may reserve for themselves a determination of the proper risk factor to use. PFD, pages 251-252. However, even within the quoted material provided in the PFD, it is clear that the PSCW's primary concern is with the collection of evidence from which the Commission could ascertain how the credit rating agencies will actually determine imputed debt. The PSCW calls on the utility to provide "supporting documentation, including reports, correspondence and any other justification that clearly establishes S&P's and other major credit rating agencies' determination of the off-balance sheet debt equivalent . . . ." PFD, page 252. Notably, Staff witness Robert F. Nichols II's direct 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.

After completing its criticism of the Company's method for calculating imputed debt, the PFD then disclaims any real connection between imputed debt and the Company's cost of capital in the first place as a means of summarizing the PFD's conclusion that the Company's FCM would overstate the costs associated with imputed debt. The PFD reasons that "there is no direct relationship between an estimate of imputed debt and Consumers Energy's cost of capital," and that "Consumers Energy's financial compensation mechanism is based on the mistaken premise that the cost of imputed debt equates to the cost of an equivalent amount of equity capital." PFD, pages 252-253. The PFD then states:

> "Of course, Consumers Energy does not actually require an additional equity investment equal to the imputed debt amount. The company's permanent capital structure finances the company's actual assets. The ratemaking capital structure used to determine the weighted average cost of capital used in setting rates is then applied to the company's approved rate base, which does not include imputed equity." PFD, page 253.

The PFD cites no record evidence in support of these propositions and does not even refer to any arguments from parties making such a claim. The PFD's observations are incorrect.

Contrary to the PFD's assertions, imputed debt clearly *does* require the Company to raise offsetting capital in order to maintain its credit metrics. Mr. Maddipati testified that "the presence of PPAs <u>increases the financial support provided by equity capital</u> and impacts the credit of a utility as a result of the imputed debt from PPAs." 7 TR 724 (emphasis added). When the PFD claims that imputed debt does not actually require an additional equity investment by the utility, it contradicts its own analysis and conclusion from the first section of the PFD's discussion of the FCM. That analysis reasoned that the Company's rate cases already include consideration of imputed debt in setting the Company's base rates. The PFD includes a block quote from the Commission's Order in Case No. U-17990 that explicitly recognized that Consumers Energy's parent company required additional equity infusions in that case in part to counteract the presence of imputed debt due to PPAs so that it could still maintain reasonable credit ratios. So, when the PFD states that "[o]f course, Consumers Energy does not actually require an additional equity investment equal to the imputed debt amount," that is false unless the Company is willing to accept a degradation in its credit metrics. When the PFD states, "The ratemaking capital structure used to determine the weighted average cost of capital used in setting rates is then applied to the company's approved rate base, which does not include imputed equity," that is technically accurate, but it overlooks two important counterpoints. First, the impact of imputed debt does not require "imputed equity" to counteract it. It requires real equity – actual cash investment in the business. Second, it is correct that this additional equity is not included in the rate base. As the PFD already pointed out in its earlier discussion of the FCM, that additional equity is included in the equity ratio of the capital structure.

For all the reasons stated above, the PFD is incorrect when it concludes that the Company's methodology for calculating the FCM is inappropriate or that the results are overstated. The Company's methodology is best suited to achieve the dual purposes for adopting an FCM and should be approved.

d. <u>The PFD Erred In Finding That The FCM Exceeds The Statutory Cap On PPA Incentives Found In MCL 460.6t(15)</u>

The PFD also concludes that the FCM should be rejected because, the ALJ claims, it exceeds the statutory cap on PPA incentive mechanisms set forth in MCL 460.6t(15). In reaching that conclusion, the PFD incorrectly compares the Company's Weighted Average Cost of Capital ("WACC") rate to the resulting PPA adder amount associated with it taken as a percentage of the per-MWh price of the PPA. But, that is not a valid comparison.

First, it is important to understand that MCL 460.6t(15) limits a PPA incentive to an amount no greater than the Company's overall WACC – not its WACC <u>rate</u>. When interpreting statutory language, a reviewing tribunal is required to "begin by examining the plain language of the statute." *Echelon Homes, LLC v Carter Lumber Co*, 472 Mich 192, 196; 694 NW2d 544, 547 (2005). "The words chosen by the Legislature are presumed intentional." *Coblentz v City of Novi*, 475 Mich 558, 572; 719 NW2d 73, 81 (2006). A tribunal may not speculate that the Legislature used one word when it meant another. *Id*. The plain language of MCL 460.6t(15) directs that a PPA incentive may not exceed the utility's WACC; i.e. the weighted average <u>cost</u> that the Company incurs to obtain its capital. Costs are expressed in dollars, not percentages. The Legislature did not use the term "WACC rate" in the statute, and that choice is presumed to be intentional. The Commission may not speculate that the Legislature meant to use the term "WACC rate" in MCL 460.6t(15). When determining the Company's cost of capital in a rate case, the Company's <u>WACC</u> is a product of the WACC rate multiplied by the Company's rate base. Therefore, in order to determine whether the Company's proposed FCM satisfies the requirement of MCL 460.6t(15), it is necessary to ensure that the comparison includes both: (i) a comparable incentive rate, applied to (ii) a comparable base.

Mr. Maddipati explained the error in Staff's similar claim regarding the lawfulness of the proposed FCM as follows:

> "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.' <u>Such a statement would only make sense if you were to treat a PPA as creating a capital asset</u>, 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 (emphasis added).

As Mr. Maddipati's testimony notes, Staff's analysis does not calculate the incentive payment as a percentage of the NPV of the PPA, which is the base that would be comparable to a capital asset. By way of analogy, when a lender finances the purchase of a residential house under a long-term fixed interest rate, the interest rate is applied to the outstanding balance remaining on the loan. Under recent market conditions, that interest rate might be something like 4% of the outstanding principal balance for example. But, as every homeowner knows, the interest amount charged to the buyer may be as much as 60% or 70% of the monthly payment amount in the earlier years, declining over time. It would be erroneous to conclude that the lender is earning 60% or 70% interest on the loan merely because the interest amount was 60% or 70% of the payment. That is because the amount of the monthly payment is not the correct base to use in calculating the interest cost. Even if the lender levelized the interest cost across all of the payments, the interest taken as a percentage of the monthly payments might be 15% or 20% or more, but that does not change the fact that the interest remains 4% of the outstanding annual balance.

The PFD's analysis makes this same error when it claims that the incentive that the Company would earn under its proposed FCM is 24.2% in the example of a hypothetical 25-year PPA. See PFD, page 254. That value takes the incentive amount as a percentage of the PPA payments, not as a percentage of the NPV of the remaining amount of the PPA, which is the appropriate base. Contrary to the PFD's claims, Mr. Maddipati's testimony (7 TR 730) and his Exhibit A-52 (SM-1) demonstrated mathematically that the Company's FCM produces a fixed incentive rate of 3.35% when calculated relative to the correct base. As a result of the design of the FCM, the fixed incentive rate of 3.35% remains the same whether the PPA in question is a 10-year PPA, a 20-year PPA, or a PPA of any other term of years. The 3.35% incentive rate produced by the Company's proposed FCM is clearly lower than the Company's WACC rate of 5.89%[21] and will necessarily produce an incentive amount that is lower than the Company's WACC. Therefore, it is well within the statutory cap set forth in MCL 460.6t(15),

e. **The PFD Misunderstands The Benefit Of The FCM To Facilitate A "Least-Cost" Strategy Of Supply Acquisition**

On pages 254 through 257, the PFD takes the position that the FCM is not needed because there appears to be other reasons why the Company would enter into PPAs even absent an incentive. The PFD points to the fact that the Company's existing generation comprises only about 70% of the Company's capacity portfolio and to the requirements of PURPA that creates a legal obligation in certain circumstances to enter into a PPA. The PFD characterizes the choice as involving an incentive to pursue a "least-cost strategy," but that characterization doesn't

[21] Furthermore, the 5.89% WACC rate that Mr. Maddipati used as a point of comparison is the Company's after-tax WACC rate. The Company's pre-tax WACC rate, which is the amount actually used to calculate the Company's revenue requirement, is 7.29%.

accurately represent what might actually be occurring. Particularly in the case of PURPA PPAs, when there is an open-capacity position and a QF establishes a legally enforceable obligation, the Company may be compelled to enter into a PPA with that QF regardless of whether the contract price constitutes the "least-cost" option available at the time. 18 CFR 292.304(f). The PFD fails to recognize the significant risk of that occurring on a large scale during the period of time contemplated by this IRP.

With respect to PURPA contracts, the PFD comments that Company witness Torrey provided no explanation about how the Company could "avoid complying with PURPA" if the Commission ultimately fails to approve an FCM sufficient to incent broad reliance on PPAs. PFD, page 256. This ignores the interrelated nature of the IRP and the vital interplay between the various components of the Company's carefully designed PCA. The Company could not "avoid complying with PURPA," but the Company could avoid coming into an open-capacity position if it elected to build a single, large capacity resource to replace retiring units instead of pursuing its clean, lean, and modular strategy. Under those circumstances, PURPA does not require the Company to contract with new QFs for full avoided cost. Consumers Energy believes that there are a number of advantages to the clean, lean, and modular strategy, but in order to execute that strategy, it is imperative that the Commission approve an FCM in this case.

Likewise, the PFD does not recognize that for the approximate 30% of PPAs that are currently part of the Company's capacity portfolio, the Company and its customers are now bearing the imputed debt costs of those contracts even though those costs would have been invisible at the time the contracts were entered. If the Company's proposed FCM had been in place at the time of those contracts, the FCM would have rendered those costs visible so that they could be evaluated as part of the contracting decision and to ensure that they were the least-cost options available.[22]

In its Initial Brief in this case, the Company responded to arguments from several parties that essentially made the same argument as the PFD does that Consumers Energy currently has PPAs totaling up to approximately 3 GW 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. 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. The Company is proposing a competitive bidding process for all future capacity procurement that could result in most, if not

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[22] The PFD also overlooks the possibility that at least some of the existing PPAs that are part of the Company's current capacity portfolio were only least-cost options when they were entered because other complex circumstances existing at the time rendered the alternatives infeasible or less practicable. The Company's two largest PPAs are both with generators that were owned, at least in part, by Consumers Energy before they were divested and converted to PPAs. Under circumstances in which the most economically reasonable alternative requires divesting an asset, but the asset cannot reasonable sold without the security of a PPA, the concept of "least-cost option" might not be as simplistic and linear as the PFD assumes.

all, of the Company's generation needs being satisfied by PPAs instead of Company-owned generation. The PFD simply fails to appreciate the unprecedented scale of the Company's proposal when it concludes that a small proportion of current reliance on PPAs somehow proves that no FCM is necessary to incent reliance on PPAs in that potential magnitude.

After discussing the example of current PPAs and PURPA PPAs, the PFD then discusses the general requirement found in various statutory provisions that, whatever capacity resource Consumers Energy pursues, the Company has an obligation to ensure the costs will be reasonable and prudent. Consumers Energy does not dispute that point. But, the PFD fails to recognize that the only effective way to ensure that the least-cost option remains visible throughout the procurement process is to include all of the costs associated with each available option as part of the consideration. Where PPAs create hidden costs as a result of imputed debt, the FCM facilitates the reasonableness and prudence review that the PFD emphasizes by making those costs visible.

f. <u>The PFD Criticizes A Claim Of "Unfairness" That The Company Did Not Make</u>

On pages 258 and 259, the PFD discusses rebuttal testimony offered by Company witness Maddipati in response to direct testimony from SEIA witness Kevin M. Lucas regarding his denial that PPA developers are relying on the Company's equity to finance their generation projects. The PFD states that "the company argues it should receive the incentive payments to remedy a perceived unfairness due to the claimed use of the company's capital structure by the PPA suppliers." PFD, page 258. The PFD later states, "This perceived unfairness claim is unsupported." PFD, page 259. It should be noted at the outset that Mr. Maddipati did not use the words "fair" or "unfair" in connection with his rebuttal to Mr. Lucas. This part of the PFD addresses a claim that the Company did not actually make.

The reason that this issue is not really an issue of "fairness" or "unfairness" is that it is principally about providing visibility into the costs associated with PPAs. The imputed debt impacts of PPAs are hidden absent an FCM. But, as long as the imputed debt costs are considered and incorporated into the Company's ratemaking capital structure as part of a rate case, as the PFD claimed they have historically been, then customers will pay those costs with or without an FCM and the Company will be reimbursed for those costs with or without an FCM. Given recent arguments by parties in the Company's rate cases, the Company is concerned that this issue could transform into an unfair situation if the Company were denied cost recovery for these imputed debt impacts in both the FCM and in future rate cases, but at present, no party is claiming that is what has happened.

Instead, the FCM makes the imputed debt costs visible and allows the Company to evaluate the full cost of entering into a particular PPA at the time the procurement decision is made. The PFD claims that, when the Company enters into a new PPA, it "avoids the need to raise additional capital...." However, that is not correct. PPAs *do* create the need for the utility to raise additional capital in order to maintain the utility's credit metrics. The FCM is needed because, among other things, it provides a built-in mechanism to ensure that those capital costs are recovered and that they are considered as part of the procurement decision. Contrary to the PFD's assertion, there are good reasons for approving an FCM arising out of the reality that the Company's equity capital is required to support the financing of PPAs beyond the notion of whether that fact is "fair" or "unfair."

g. The PFD Erred In Finding That The FCM Creates An Unfair Advantage To The Company In Evaluating Competitive Bids

At pages 259 through 265, the PFD concludes that the Company's plan to use an FCM in the evaluation of bids from third parties in the competitive bidding process creates "an unfair advantage for the company and its affiliates." This conclusion is misplaced. The PFD fails to properly consider the purpose of the FCM and the bid evaluation process proposed by the Company in this IRP proceeding.

The Company's proposal to use an FCM in the bid evaluation process does not create an unfair advantage for the utility. The use of an FCM in the bid evaluation process takes away an unreasonable and harmful advantage that PPAs have over utility build options. When the Company enters into a PPA with a third party, the Company takes on an obligation to pay for energy and capacity and also incurs hidden imputed debt costs. By including the FCM in the bid evaluation process, the PPA's true cost to the Company and customers will be evaluated. This allows utility-built generation to be evaluated on an equal playing field with PPAs.

The PFD also incorrectly concludes that "the Company's proposal fails to consider any additional risk that may be associated with company-built generation, including operational costs." PFD, page 261. While the PFD fails to provide any explanation as to what additional risks the Company failed to consider, the record makes clear that the Company is proposing to evaluate the total cost of utility build options. The Company is proposing to evaluate PPA proposals received in the competitive bidding process, including any FCM applicable to the proposals, "against ***the cost of utility build options***, which would have been submitted by the Company." 8 TR 1381 (emphasis added). The Company further explained that it would develop and submit bids in the competitive solicitation process as follows:

> "The Company would perform early stage development – acquiring real estate and local permits, applying for generator interconnection agreements, 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 would be used as benchmarks for evaluating bids by others." 8 TR 1381.

The Company's proposal to use development and construct costs and the costs of delivered energy in its bids, means that the Company will fully consider all costs, and corresponding risks, that the Company will encounter in its ownership of the generation asset. The record does not support the PFD's conclusion that the Company will not consider all costs related to utility-built generation in its evaluation of PPA bids.

Beyond the above, the PFD's criticism of the Company's proposal to use an FCM in the evaluation of third-party bids does not to consider that the Company's PCA does not assume that the Company would unilaterally construct the new solar resources, which make up the PCA. 7 TR 1381. The Company anticipates that third party development would be an integral component of the plan by "creating more flexibility, diversity of locations, competitive pricing, and capability to develop the amount of solar in the plan." 8 TR 1382. This means that there will likely be many instances during the implementation of the PCA where the Company will not bid utility-built generation against PPAs, particularly in the early years of the Company's plan. 8 TR 1382. Since utility-built generation will not always be evaluated against PPAs, the Company does not seek to create "an incentive that paradoxically will make PPAs more expensive relative to company owned generation," as the PFD suggests. PFD, page 261. The Company only seeks to reflect the true cost of a PPA in the bid evaluation process and also seeks to place utility-built generation and PPAs on a level field, in the instances when the Company's submits its own bids.

The PFD's criticism of the Company's evaluation of PPAs and utility-built generation also disregards the Company's proposal to use an Independent Evaluator in the competitive bidding process. The Company is proposing that an Independent Evaluator conduct the evaluation phase of the competitive bidding process. The Independent Evaluator will evaluate all bids submitted and will develop a short-list of projects without any contact with the Company. The Company would then select projects from a "blind list" which would provide "[o]nly the information necessary to make the determination." Such information would include "the net cost (adjusted by applicable value-added characteristics) and commodity volumes for each project." 8 TR 1287-1288. Furthermore, the Company proposes that the Independent Evaluator will make all solicitation materials available for Staff review. 8 TR 1287. These processes ensure that the Company does not have an unfair advantage during the competitive solicitation process.

The PFD's suggestion that affiliates could get preferential treatment under the Company's competitive bidding proposal is also unsupported. The PFD appears to conclude that since the Company is unable obtain an FCM for PPAs that it enters with affiliates, pursuant to MCL 460.6t(15), affiliate bids would not be evaluated with an FCM. PFD, pages 260-261. However, the PFD misses the fact that any affiliate participation in a Company solicitation requires approval by FERC and would require compliance with the Commission's Code of Conduct. 8 TR 1284. The Company would have to establish that an affiliate bid was not unfairly selected over non-affiliate bids and would therefore, be precluded from considering the total cost of a non-affiliate PPA without giving equal consideration to an affiliate bid. 8 TR 1368. The competitive solicitation process proposed by the Company in this case is modeled after the Company's previous reverse capacity auctions, which were approved by FERC for affiliate participation, adhered to the requirements of the Commission's Code of Conduct, and approved by the Commission in Case Nos. U-17725, U-18194, and U-18382. 8 TR 1284, 1289.

h. The PFD Erroneously Concludes That The FCM Should Be Rejected Based On The Incorrect Finding That The Company Required Its Filed FCM Or No FCM

On page 266, the PFD indicates “the company has made clear only its proposed [FCM] is acceptable” and therefore, does not consider any of the alternative FCM proposals presented in this case. The PFD’s representation of the Company’s position is incorrect. That Company has indicated that with certain modifications, it could support proposals presented by MEC and Staff. These modified proposals should be considered by the Commission in its order.

While the Company continues to support its originally proposed FCM, the Company has made clear that alternatives would be acceptable under the correct circumstances. Staff witness Proudfoot proposed that, in lieu of an FCM, the Commission could allow the Company to own 50% of the generating assets it is proposing to procure with the other 50% coming from PPAs. 9 TR 2564-2566. Mr. Proudfoot indicated that this construct would be a “continuation of the fifty percent limitation on company-owned resources that was included in [2008] PA 295” which led to increased competition and drove prices down for customers in Michigan, including lower prices for Company-owned renewable resources.” 9 TR 2564. Mr. Proudfoot further noted that:

> “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.” 9 TR 2566.

While the Company agrees with Mr. Proudfoot’s explanation of the benefits of utility ownership of generation, the Company maintains that an FCM would still be necessary in order for the Company to move forward with Mr. Proudfoot’s proposal to procure 50% of its future generation from PPAs – although that FCM could be less than what the Company originally proposed. Company witness Maddipati specifically explained that Mr. Proudfoot’s proposal to allow the Company to own up to 50% of its generation resources and allow for competitive bidding of the remaining 50% would be reasonable if coupled with the FCM methodology proposed by MEC witness Jester, which can be calculated at 9.27%.[23] 7 TR 759.

In addition, Mr. Maddipati also indicated that an FCM of 9.27% could be reasonable with a PPA term which does not exceed 10 years in length. 7 TR 759. As part of the Company's competitive bidding proposal, the Company has proposed that "[t]he maximum term length of the PPA should be equivalent to the depreciation schedule of a similar Company-owned asset." For solar resources, which the Company intends to primarily procure as part of the PCA, this would equate to a PPA term of 25 years. 8 TR 1289. Therefore, if a 9.27% FCM is utilized, the Company would agree to PPA terms of 10 years in duration instead of the 25 years originally proposed. This PPA term length appropriately balances the lower FCM amount, when compared to the amount originally proposed by the Company, and the hidden imputed debt costs that the Company would incur by entering PPAs.

i. <u>Conclusion</u>

The Company has been clear that an FCM is needed for two principal reasons: (i) to incent the Company to voluntarily engage in a clean, lean, and modular procurement plan that exposes Consumers Energy to the risk that a significant proportion – and potentially all – of the Company's future capacity acquisitions would be met through PPAs; and (ii) to fairly incorporate the impacts of imputed debt caused by PPAs so that the costs are visible at the time of procurement and so that there is a built-in vehicle for recovery of those costs. Because of these attributes of the FCM, it is a pivotal part of the Company's overall IRP as set forth in the PCA. The PFD's recommendation to simply reject the Company's FCM does not adequately or

[23] Company witness Maddipati calculated the 9.27% FCM based on corrections to Staff's FCM methodology. 7 TR 749. Mr. Maddipati explained that the 9.27% FCM amount is identical to the FCM presented by MEC witness Jester.

correctly consider the dual needs for it discussed above, nor does it appropriately analyze the ramifications to the remainder of the parts of the PCA if it is not there. The reasons cited by the PFD to explain away the need for an FCM are not responsive to the evidence presented by the Company to explain the dual needs supporting the approval of the FCM and do not have merit. The Commission should reject the recommendation of the PFD and approve an FCM consistent with the Company's proposal in this case.

5. <u>Unrecovered Book Balance</u>

a. <u>The PFD's Determination That The Company's Request For Regulatory Asset Treatment For Cost Recovery Related To The Retirement Of Karn Units 1 And 2 Is Outside The Scope Of The IRP Is In Error</u>

With regard to the Company's request for regulatory asset treatment for the unrecovered plant balances and net salvage costs for Karn Units 1 and 2, the PFD found "Staff's analysis persuasive," and further found "the Company's request is outside the scope of this case." PFD, page 292. Without responding to the evidence or arguments presented by the Company or MEC, the PFD agrees with Staff and says that the "Company did not establish a logical connection between its retirement decision, which is legitimately a part of its IRP, and the accounting treatment requested for the remaining plant balances when the units retire." PFD, page 293. This rationale is not based on record evidence or a proper interpretation of the language of the statute and, thus, should not be accepted by the Commission.

Mr. 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 asserted 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.*" 9 TR 2547 (emphasis added).

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. In this matter, Company witness Heidi J. 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 treatment through 2031 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 <u>existing</u> 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 Richard T. 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 <u>existing</u> and proposed resources. While Mr. Proudfoot argues that a "forward-looking plan" spanning at least the next 15 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 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. The statute's plain language provides for analyses of "costs" related to "existing" electric generation facilities. In fact, Section 6(t)(5)(k) expressly 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. Further, while Staff's position would limit the Commission's authority, the Commission has broad ratemaking authority and can, within that authority, make a determination regarding accounting treatment, including the regulatory asset treatment requested by the Company in this case.

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," a determination regarding the recovery of the Karn Units 1 and 2 unrecovered book balance should be made by the Commission in this case. 7 TR 1049.

It is important to note that in MEC's Initial Brief, it recommend that the Commission approve the Company's proposal to establish a regulatory asset for retirement of Karn Units 1 and 2 so that the Company can recover its costs for retiring those units before the end of its respective previously-established depreciation life. MEC's Initial Brief, page 83. Additionally, MEC recommends that the Commission authorize amortization of the proposed regulatory asset through 2031, "unless, as Mr. Jester recommends, the Commission authorizes securitization of the costs that the regulatory asset covers" (citation omitted). MEC continued by saying:

> "However, in light of the potential savings for customers that Ms. Myers's analysis demonstrated, and to give the Commission sufficient time to reach a decision between securitization and amortization of the proposed regulatory asset, the Commission should require Consumers to file a securitization request for the retirement of Karn Units 1 and 2 not later than July 1, 2021. Filing a securitization request at that time should not be unduly burdensome for the Commission or the Company, because, as Ms. Myers noted in her direct testimony, "the amounts in this regulatory asset will be easily identifiable should securitization be considered in the future." MEC's Initial Brief, page 84 (citations omitted).

While the Company agrees with MEC's recommendation for regulatory asset treatment, as Ms. Myers indicated in her direct testimony, securitization is not the preferred treatment of remaining unrecovered book value of Karn Units 1 and 2. As Ms. Myers explained, in order to retire Karn Units 1 and 2 in 2023, "the Company needs cost-recovery certainty approved *in this proceeding*." 7 TR 1042 (emphasis added). Because securitization cannot be approved in this proceeding, "[t]here would need to be a separate securitization application, contested case, and Commission order – the outcome of which is uncertain until well into the future." 7 TR 1042. This uncertainty, along with some of the direct and indirect negative impacts of securitization, such as adverse impacts on the Company's corporate rating and negative effects on both the Company's cost of capital and credit ratings (see Company witness Todd A. Wehner's direct testimony, 8 TR 1506- 1509), makes a securitization option not the optimal solution in this case.

Based on the foregoing, the Commission should reject the PFD's finding that approval of regulatory asset treatment is outside the scope of these IRP proceedings, approve the Company's proposal to establish a regulatory asset for retirement of Karn Units 1 and 2, and also authorize the amortization of the proposed regulatory asset through 2031.

6. Cost Approvals

a. The PFD's Recommendation To Not Pre-Approval O&M Expenses Is Inconsistent With The Law And The Commission's Broad Ratemaking Authority

On page 293, the PFD adopted Staff's position that O&M expenses should not be pre-approved pursuant to MCL 460.6t(11) without providing any analysis to support this recommendation. The PFD's recommendation should be rejected because it is inconsistent with the law and otherwise unreasonable.

The Commission has the authority to pre-approve both capital and O&M costs in the context of an IRP proceeding. MCL 460.6t(11) indicates that, in an IRP case, "the commission shall specify the costs approved" for four different categories. First, the Commission can pre-approve costs for "the construction of or significant investment in an electric generation facility." Second, the Commission can pre-approve costs for "the purchase of an existing electric generation facility." Third, the Commission can pre-approve costs for "the purchase of power under the terms of the power purchase agreement." Finally, the Commission can pre-approve costs for "other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan."

While it could be argued that the first two categories included in MCL 460.6t(11) pertain to capital investments, the second two categories go beyond capital investments. The costs for "the purchase of power under the terms of a power purchase agreement" are not limited to capital investments. When the Company enters into a PPA with a counterparty, the Company is not investing in that facility. PPA costs are recovered through the PSCR mechanism, which provides for the recovery of fuel costs, classified as O&M expenses. Furthermore, PPAs typically include a capacity payment, which is attributable to fixed plant costs and an energy payment, which is attributable to variable costs at a plant and typically classified as O&M.

The fourth category in MCL 460.6t(11), which includes the costs for "other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan" also goes beyond capital investments. In this category, the Legislature provided for the cost approval of "other investments" and the costs for "resources" which are "used to meet energy and capacity needs." The Michigan Supreme Court has made clear that, in interpreting a statute, courts "must give effect to every word, phrase, and clause in a statute and avoid an interpretation that would render any part of the statute surplusage or nugatory." *State Farm Fire & Cas Co v Old Republic Ins Co*, 466 Mich 142, 146, 644 NW2d 715 (2002). If the Legislature had intended the Commission's pre-approval to apply to only capital investments, as

Staff suggests, there would be no need to distinguish "resources" from "other investments." Interpreting this category to only include capital investments would render the distinction of "resources" meaningless.

Interpreting the fourth category in MCL 460.6t(11) to only include capital investments would also preclude the Commission from pre-approving costs for *all* "resources used to meet energy and capacity needs that are included in the approved integrated resource plan." For instance, in this IRP the Company is proposing to utilize increases in EWR to provide capacity value to customers. This capacity value is provided to customers with O&M costs and requires no capital investment. If the Company's PCA were to be approved by the Commission, Staff's interpretation of MCL 460.6t(11), as adopted by the PFD, would unreasonably preclude the Commission from pre-approving the costs of this resource, which will be used to meet energy and capacity needs.

Furthermore, even if the provisions of MCL 460.6t did not include the pre-approval of O&M costs, which the Company does not agree, the Commission would still have the authority to pre-approve the recovery of O&M costs in this proceeding. Courts have made clear that the Commission has broad ratemaking authority. See, e.g., *Attorney Gen v Michigan Serv Comm'n*, 231 Mich App 76, 79, 585 NW2d 310 (1998). The Commission could exercise its broad ratemaking authority to pre-approve the O&M costs for CVR, DR, and EWR that the Company has sought pre-approval of in this proceeding.

Therefore, contrary to the PFD's finding, the Commission has the authority to approve O&M costs in this case. The Commission should reject the recommendation of the PFD and 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

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.

If the Commission declines to pre-approve the identified EWR, DR, and CVR O&M costs in this case, as proposed by the PFD, the Company 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.[24] 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.

7. Recommendations For The Company's Next IRP

a. The PFD Erred In Adopting Staff's Recommendation For The Company's Next IRP Filing In Their Entirety

On pages 295 through 296, the PFD recommended adoption of all of Staff's recommendations for the Company's next IRP filing. While the Company and Staff agree on the majority of Staff's recommendations, the Commission should not adopt Staff's recommendations in their entirety, as the PFD recommends.

[24] Staff indicated on page 44 of its Revised Initial Brief that "[t]he specified O&M expenses for the first three years of the IRP for EWR, DR, and CVR are reasonable."

Staff recommends that "the Company use hourly time intervals or, at a minimum, daily time intervals for energy sales and peak demand forecast regression models." See Staff's Revised Initial Brief, page 84. The Company disagrees with Staff's recommendation. Though the model may or may not be enhanced by using more granular data, the Company cannot currently meet this request. 8 TR 1664. The models use 15 years of historical data that have 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. Since smart meters have not yet been deployed for 15 years, this is not possible. 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.

The Company also disagrees with Staff's recommendation that the Company report monthly Mean Absolute Percentage Error ("MAPE") results for the period between IRP cases. See Staff's Revised Initial Brief, pages 85-86. The peak demand regression model generates monthly peaks and the model evaluation returns a MAPE for the entire model. 8 TR 1664-1665. Procuring a MAPE for each monthly peak, as Staff recommends, 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.

Staff further recommends that the Company should optimize future plans by modeling renewable resources and battery storage together and examining residential scale storage programs. Staff's Revised Initial Brief, pages 86-78. 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 battery storage. 6 TR 270. 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.

Staff also proposes additional reporting requirements to track the progress of CVR Program implementation and address Staff's concerns with the CVR Program. Staff's Revised Initial Brief, page 88. In response to Staff's proposal, the Company indicated in testimony that it agrees that CVR reporting should be completed and reviewed by Staff but proposed to use the Company's model, as opposed to the template in Exhibit S-14.1 (TJB-2), to prevent the duplication of work. 8 TR 1638-1639. In its Revised Initial Brief, Staff agreed with the Company's proposal to use its model for reporting purposes. Staff's Revised Initial Brief, page 89. The PFD did not acknowledge this agreement between the Company and Staff and therefore it is not clear if the PFD is recommending Staff's original recommendation or the agreed upon model. In its final order, the Commission should make clear that Staff and the Company have agreed to the use of the Company's model for CVR reporting and that the Company is not required to use the template in Exhibit S-14.1 (TJB-2).

IV. CONCLUSION

For the reasons set forth in these Exceptions, Consumers Energy Company's Initial and Reply Briefs, and the evidentiary record in this matter, the Company respectfully requests that the Michigan Public Service Commission reject the PFD and approve the PCA, in its entirety, as the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. The Company further 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 its briefs and the Company's record evidence.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Digitally signed by Robert W. Beach
Date: 2019.03.04 16:34:46 -05'00'

Dated: March 4, 2019

By: ______________________________

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief	)))))	Case No. U-20165

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on March 4, 2019, she served an electronic copy of the **Exceptions 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.

Melissa K. Harris
Digitally signed by Melissa K. Harris
Date: 2019.03.04 16:35:37 -05'00'

Melissa K. Harris

Subscribed and sworn to before me this 4th day of March, 2019.

Crystal L. Chacon
Digitally signed by Crystal L. Chacon
Date: 2019.03.04 16:36:31 -05'00'

Crystal L. Chacon, Notary Public
State of Michigan, County of Ingham
My Commission Expires: 05/25/24
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-20165

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