OLSON, BZDOK & HOWARD

June 24, 2020

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

Via E-filing

RE: MPSC Case No. U-20697

Dear Ms. Felice:

The following is attached for paperless electronic filing:

PUBLIC Direct Testimony of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan

Proof of Service

*****NOTE: Confidential Testimony and Exhibits will be served upon those with a signed ND on file*****

Sincerely,

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xc: Parties to Case No. U-20697

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief	)))))	Case No. U-20697 ALJ Sally Wallace

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PUBLIC

Direct Testimony

of

Tyler Comings

On Behalf of

Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan

June 24, 2020

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I. Introduction and Qualifications

Q. Please state your name, business address, and position.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University's Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. Please summarize your work experience and educational background.

A. I have 14 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, New Jersey, New Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons (AARP), Appalachian Regional Commission, Citizens Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Massachusetts Division of Insurance, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Exhibit MEC-69.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan (CUB).

Q. Have you testified before the Michigan Public Service Commission previously?

A. Yes, on three occasions. In January of 2020, I submitted testimony on the Indiana Michigan Power Company (I&M) Integrated Resource Plan (IRP) in Case No. U-20591. In 2018, I submitted testimony on the Consumers Energy Company 2018 IRP in Case No. U-20165 and on the Consumers Energy Company 2018 rate case in Case No. U-20134.

Q. What is the purpose of your testimony?

A. I address two main issues in my testimony. First, the primary focus of my testimony addresses the value of coal-fired units 1 and 2 at the J.H. Campbell plant, and Consumers Energy Company's (Consumers or "the Company") request for rate recovery of certain capital investments in these two units. I also discuss several capital projects at Campbell unit 3 for which Consumers is also seeking cost recovery. Second, I discuss the transition planning efforts related to Karn units 1 and 2, two coal-fired units scheduled for retirement in May 2023.

Q. What information did you review in preparing your testimony in this case?

A. I reviewed the Company's testimony, exhibits, workpapers, and discovery responses.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I sponsor Exhibits MEC-69 to MEC-99:

MEC-69:	Comings Resume
MEC-70:	MEC-CE-32 + MEC-CE-32-Hugo_ATT_2
MEC-71:	MEC-CE-033 + MEC-CE-033-Hugo_ATT_1
MEC-72:	MISO 2020/21 PRA results
MEC-73:	Letter from Michigan PSC to MISO (Nov. 7, 2019) + Michigan Capacity Import/Export Limit Expansion Study Update (May 19, 2020)
MEC-74:	Resource Adequacy Subcommittee (RASC) Meeting, Item 03a – PRA results
MEC-75:	Case No. U-20154 Staff Report - Final 3-28-2019
MEC-76:	Case No. U-20734, Application and Direct Testimony of David Ronk
MEC-77:	MEC-CE-1009
MEC-78:	MEC-CE-1370 + MEC-CE-1370-ATT_1 (excerpt)
MEC-79:	Fixed O&M Costs at Campbell 1&2
MEC-80:	MEC-CE-535
MEC-81:	Capacity Factors, Availability, Periodic Factors, and Random Outage Rates for Campbell 1&2
MEC-82:	MEC-CE-044, MEC-CE-045, & MEC-CE-1014
MEC-83:	Comings Tables (recommended disallowances)
MEC-84:	MEC-CE-544 + MEC-CE-545
MEC-85:	Projected capital expenditures at the Campbell plant, 2021-24[1]
MEC-86:	Projected major maintenance expenditures at the Campbell plant, 2021-24[2]
MEC-87C:	MEC-CE-1013-CONF + MEC-CE-1027-CONF
MEC-88:	MEC-CE-035 (3rd Supp.)
MEC-89C:	MEC-CE-1026-CONF
MEC-90:	MEC-CE-1012

[1] Based on information provided by the Company in MEC-CE-545 ATT 1, MEC-CE-1014 ATT 1, ST-CE-265 ATT 1, MEC-CE-35 ATT 2nd Revised, and MEC-CE-1017.

[2] Based on information provided by the Company in MEC-CE-544-Hugo_ATT_1, MEC-CE-1015 ATT 1, ST-CE-265 ATT 1, MEC-CE-35 ATT 2nd Revised, and MEC-CE-1018.

MEC-91: MEC-CE-1020
MEC-92: MEC-CE-1017 + MEC-CE-1018
MEC-93C: MEC-CE-1021-CONF
MEC-94: Hugo WP-SAH-23
MEC-95: MEC-CE-546
MEC-96C: MEC-CE-053-Hugo_CONF_ATT_1
MEC-97: MEC-CE-549
MEC-98: MEC-CE-053 + MEC-CE-053-Hugo_ATT_3
MEC-99: MEC-CE-1029

Q. Please describe the Campbell and Karn coal-fired units.

A. The Company owns five coal-fired generating units at the Campbell and Karn plants:[3]

- Campbell Unit 1: 259 MW capacity, 58 years old
- Campbell Unit 2: 348 MW capacity, 53 years old
- Campbell Unit 3: 784 MW capacity (Consumers' owned share), 40 years old
- Karn Unit 1: 255 MW capacity, 61 years old
- Karn Unit 2: 260 MW capacity, 59 years old

Q. What is the status of the Company's plans for retiring these units?

A. The Company is currently planning to retire Campbell units 1 and 2 in 2031, Campbell unit 3 in 2039, and Karn units 1 and 2 in 2023.[4] The Company selected these dates as part of its Proposed Course of Action (PCA) in the 2018 IRP.[5] In the

[3] Direct Testimony of Scott A. Hugo, p. 6, Table 1.
[4] *Id.* Table 1 of the Mr. Hugo's testimony lists a 2040 retirement date for Campbell 3, but Consumers previously identified a 2039 date in its 2018 IRP. *See* Case No. U-20165, Revised Direct Testimony of Thomas P. Clark, 7 TR 880.
[5] Case No. U-20165, Application, p. 2

subsequent case reviewing this IRP, No. U-20165, MEC-NRDC-SC challenged Consumers' proposal to operate Campbell units 1 and 2 through 2031. Subsequently, Consumers and most parties in that case reached a settlement, which the Commission approved. Under the settlement agreement, Consumers confirmed the retirement of Karn units 1 and 2 in 2023 but also agreed that its next IRP would evaluate the retirement of Campbell units 1 and 2 in 2024, 2025, 2026, 2027 and 2031.[6] That IRP will be filed in June 2021. Currently, the retirement of the Karn units in 2023 is moving forward, but the question of when Campbell units 1 and 2 will retire will be re-evaluated in next year's IRP.

Q. How is the retirement year for Campbell Units 1 and 2 relevant to this current rate case?

A. For Campbell units 1 and 2, the Company is seeking rate recovery of $24.4 million in capital expenditures and $10.6 million in major maintenance expenditures in the 2021 test year.[7] Capital projects are typically medium to long-term investments that are financed with debt and equity and recovered over many years. Major maintenance projects are part of operations and maintenance (O&M) and, unlike capital costs, are expensed rather than financed over many years.[8]

[6] Case No. U-20165, June 7, 2019, Order Approving Settlement Agreement, Exhibit A, Pars 3-4.
[7] Ex A-69 (SAH-4) Revised (filed June 16, 2020); Ex A-70 (SAH-5) p.3; see also wp0620-Hugo-22 (Revised).
[8] The Company categorizes its O&M spending into several different components, including Base O&M expenses (which are incurred annually) and major maintenance (which are larger projects that not necessarily performed annually. See Hugo Direct, p. 112 (describing major maintenance expenses).

Planned capital and maintenance spending should change with the units' retirement year(s). Some expenditures can be avoided if the units retire earlier because that planned spending is either no longer necessary or not cost-effective. As part of the Commission-approved settlement agreement in the IRP case, the Company agreed to identify these "avoidable" costs in this rate case. Specifically, the Company agreed to identify costs that could be avoided if Campbell units 1 and/or 2 retired in 2024 or 2025.[9] As a result, the Company has identified a subset of the projected test year costs that are avoidable with earlier (2024 or 2025, rather than 2031) retirement of the units.

Because the retirement date of Campbell units 1 and 2 will be reconsidered, the identification of avoidable costs is important for the Commission's determination of which costs to allow in rates. The retirement dates are relevant because they affect whether the planned capital and maintenance spending costs are reasonable and prudent. Including avoidable costs in rates now would prevent ratepayers from realizing this savings should the units retire earlier.

Q. Please summarize your findings and recommendations.

A. Based on my review of the Company's filing and data responses in this case, I conclude that:

1. **Campbell units 1 and 2 should be considered for retirement in 2024 or 2025.** A comparison of the economic value of the two units—both the energy and capacity value that they provide—to the costs borne by ratepayers shows

[9] Case No. U-20165, June 7, 2019, Order Approving Settlement Agreement, Exhibit A, Par 6.

that the units' costs significantly outweigh their value. Also, the units have become less available in recent years due to unplanned outages. The Company expects this performance to continue to degrade in coming years, but its projections of energy and capacity value of the units do not appear to account for this degradation. Given the poor economics of the units, the Company should consider retiring the Campbell units in 2024 or 2025 after a rigorous, forward-looking assessment.

2. **The Commission should disallow rate recovery of capital and major maintenance costs at Campbell units 1 and 2 that are avoidable if the units retire in 2024.** In this case, the Company is seeking approval of $8.13 million of capital and major maintenance projects at Campbell units 1 and 2 that may be avoided if these units were to retire in 2024 instead of 2031. Some of these expenditures were identified by Consumers in Exhibits A-69 (SAH-4) Revised and A-71 (SAH-6), and, after reviewing the Company's discovery responses, I identified two additional projects that are likely avoidable with a 2024 retirement. Given Campbell 1 and 2's questionable economics and expected poor future performance, the Company has not justified the units' continued operation, and the Commission should disallow rate recovery of these avoidable expenditures because they are imprudent and unreasonable.

3. **The Commission should disallow rate recovery of significant capital and major maintenance costs that lack justification or have inconsistent cost estimates.** In this case, the Company is seeking recovery for many capital and major maintenance projects at the Campbell plant that lack supporting

documentation or that suffer from discrepancies in the project cost estimates. Because the lack of support fails to show the prudence of these costs, the Commission should disallow recovery of these expenditures at this time.

4. **What the Company calls "incremental" costs for retiring Campbell units 1 and 2 are likely overstated, and nevertheless would occur regardless of when the units retire.** In its filing, the Company identified a set of "incremental" costs that, the Company asserts, would be incurred if Campbell units 1 and 2 retire in 2024 or 2025. The Company has acknowledged, however, that such costs would also be incurred if the units retire in 2031 as currently planned.[10] These cost estimates are also unsupported and likely overstated. The Commission should direct the Company, in its upcoming IRP, to provide robust estimates and ensure such costs are evaluated consistently across alternative retirement dates.

5. **The Commission should direct the Company to prepare a publicly-available, robust transition plan for retirement of Karn units 1 and 2 that includes community input.** A transition plan should be transparent, address impacts to the affected workers and community, and involve community engagement and input. In 2018, Consumers prepared a confidential community transition plan for Karn 1 and 2. At present, [[[redacted]]]. Although the Company intends to update its Karn transition plan, in updating the plan it is not consulting with

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[10] See MEC-CE-546(c) (Ex MEC-95).

local community leaders or holding public forums—nor has it expressed intention to do so— even though the community is directly affected by the post-retirement transition.

II. <u>CAMPBELL UNITS 1 AND 2 ARE COSTLY AND UNRELIABLE. THEY SHOULD BE CONSIDERED FOR ACCELERATED RETIREMENT.</u>

Q. Please summarize your assessment of the economic value of Campbell units 1 and 2.

A. In this section, I compare the value that Campbell 1 and 2 provide, in terms of energy and capacity, to the costs of owning and maintaining the units. I find that the units' costs substantially outweigh their economic value. In addition, in recent years, the units have been less reliable—as shown by their high random outage rate—and the Company does not expect this trend to reverse. Under the settlement agreement from the Consumers' 2018 IRP case, No. U-20165, Consumers is required to evaluate the potential retirement of Campbell 1 and 2 for each of the years 2024-26, 2028, and 2031.[11] Given these units' high costs and unreliability, the Company should give meaningful consideration to a 2024 or 2025 retirement.

Q. Please describe the components you considered in assessing the Campbell units' total value.

A. I considered three main categories of costs and revenues: the units' "net energy value," capacity value, and fixed costs.[12]

[11] Case No. U-20165, June 7, 2019, Order Approving Settlement Agreement, Exhibit A, Par 4(a).
[12] This approach is consistent with that taken by the Company in its previous rate case. In Case No. U-20134, the Company stated that a generating unit's "total net value to customers"

Q. Please explain net energy value.

A. The units provide value for megawatt hours (MWh) generated and sold into the MISO energy market. In this testimony, I use the Company's "net energy value" (NEV) concept, which calculates the difference between MISO energy and ancillary service revenues and the variable costs of operating the units (which are mainly fuel costs).[13] Thus, the NEV represents the energy value of MWh generated over and above the costs of producing those MWh. (This concept is sometimes referred to as the "net energy margin.") In discovery, the Company provided its calculation of the Campbell units' NEVs for several years, and also provided a projection of the units' NEVs for 2020 and 2021. I used these NEV figures in assessing Campbell 1 and 2's total value.

A. <u>Estimates of Capacity Value for Campbell 1 and 2</u>

Q. Please explain the concept of capacity value.

A. The units also provide value by being available to serve peak load—in terms of MWs—known as "capacity value." In the MISO capacity auctions, the amount of capacity provided by a resource is expressed in zonal resource credits (ZRCs) which accounts for forced or random outages at the resource. (This is also called unforced capacity or UCAP.) The value of this capacity is separate from energy value and there are several ways to measure it. Below, I describe several concepts related to capacity value, including: 1) the MISO capacity auction clearing price, 2) the cost of new entry (CONE), 3) Consumers' assumption that the future capacity value of Campbell 1 and

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can be determined by considering net energy value, capacity value, and fixed costs. *See* Case No. U-20134, Ex MEC-53, page 2.

[13] Ex MEC-70 (MEC-CE-032(b)). Revenues also include "make whole payments" and a "net generation regulation adjustment."

2 is 75 percent of CONE, and 4) the cost of capacity acquired by Consumers through bilateral contracts.

Consumers reports "capacity value" for its generating units in terms of both the MISO auction price and CONE, which in most years are vastly different values.[14] The Company claims that "both calculations were conducted to provide a range of reasonable values for the capacity of each generating unit."[15] However, as I explain below, neither is an appropriate measure of capacity value.

Q. Please describe the MISO Planning Reserve Auction (PRA).

A. The MISO PRA is a capacity auction held once a year for the following planning year, which runs from June 1st through May 31st. For instance, the most recent auction results reported in April 2020, covers the 2020/2021 planning year (June 1, 2020, through May 31, 2021). The auction covers 10 zones in the MISO region. (Both Consumers' and DTE's service territories are in Zone 7.) Based on expected peak load in a given zone, a reserve margin, and the extent to which that zone can import capacity, MISO assigns each zone a local clearing requirement (LCR). The LCR represents MISO's projection of the amount capacity needed within that zone.

Most utilities in MISO either provide their own capacity needs (by submitting a fixed resource adequacy plan or FRAP) or self-schedule their capacity by bidding zero into

[14] Hugo Direct, p. 15, Table 2.
[15] Ex MEC-71 (MEC-CE-033(a)).

the auction, which guarantees that the resources will clear the auction; only about 5 percent of capacity cleared has made up the remainder.[16]

Q. Has the clearing price in Zone 7 been low in most years?

A. Yes. The clearing prices in Zone 7 are shown below in Table 1. This shows that the clearing prices have been volatile but mostly on the low end. The latest year result is a clear outlier compared to past auctions.

Table 1: MISO PRA Zone 7 Clearing Prices ($/MW-day)[17]

MISO Planning Year	Zone 7 clearing price ($/MW-day)
2014/15	$16.75
2015/16	$3.48
2016/17	$72.00
2017/18	$1.50
2018/19	$10.00
2019/20	$24.30
2020/21	$257.30

[16] In recent years, only between 4.7% and 5.5% of cleared capacity in the PRA was not part of a FRAP or self-scheduled. See Ex MEC-72 (MISO 2020/21 PRA results, slide 8). Available at: https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf.

[17] Ex MEC-72 (MISO PRA results 2020/2021). See also MISO PRA results from planning years 2015/16 through 2019/20, available: https://cdn.misoenergy.org/2015-2016%20PRA%20Results87078.pdf; https://cdn.misoenergy.org/2016-2017%20PRA%20Results87167.pdf; https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf; https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf; https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf.

Q. Is it appropriate to rely solely on the MISO capacity price to assess the value of capacity?

A. No. The MISO capacity market (the PRA or Planning Resource Auction) clearing price is an indicator of capacity value in that it indicates whether a zone has a shortage or surplus in capacity. However, this cannot be used as the only value of capacity because, typically, MISO utilities provide most or all of their own capacity needs. The MISO PRA is a voluntary balance market, whereby utilities can sell excess capacity (i.e., above their MISO reserve requirement) or purchase a small amount as needed (i.e., to meet their MISO reserve requirement). For a vertically integrated utility like Consumers, the clearing price of this market only matters to the net amount of capacity sold or purchased by the utility. If, for instance, a utility had exactly the amount of capacity required by MISO then the PRA clearing price in that zone would not affect the utility.

The maximum clearing price in the MISO PRA is the cost of new entry (CONE) value, which is based on the annual cost of building and operating a new gas-fired combustion turbine. In past years, MISO zones mostly cleared at a small percentage of CONE. For instance, in the five auctions prior to 2020/21 planning year, Zone 7 (which includes the service territories of both Consumers Energy and DTE) cleared at an average of 9 percent of CONE.[18] In the latest auction (2020/21 planning year), Zone 7 cleared at 100 percent of CONE ($257.53 per MW-day) because the zone did not meet the MISO local clearing requirement (LCR).[19]

[18] Ex MEC-72 (MISO PRA results 2020/2021, slide 9).
[19] Ex MEC-72 (MISO PRA results 2020/2021, slide 2).

Q. Is it appropriate to rely on 100% of CONE to assess the value of capacity?

A. No. CONE should not be used as a capacity value because it is the absolute maximum price for capacity. Even if one viewed the MISO PRA clearing price as the appropriate value of capacity – which it is not – the most recent PRA result in Zone 7 is the only instance of any MISO zone ever clearing at (or near) CONE. In every other zone or year, the clearing price was far below CONE because there was a surplus of capacity.

Q. What future capacity value does Consumers assume for Campbell 1 and 2?

A. For future years, Consumers assumes each of its coal units have a capacity value of 75 percent of CONE.[20] This is the same capacity value assumption that Consumers presented in the 2018 IRP case. The Company claims that it projected this value "based on the premise that if Zone 7 was short on capacity, the capacity prices would hit CONE for 3 years and by year 4 a new resource would be available."[21]

Q. In the past, has Consumers agreed that the use of the MISO PRA clearing price is not appropriate as a capacity value measure?

A. Yes, but the Company has been inconsistent on this point. In the 2018 IRP case, Consumers witness Thomas Clark, in criticizing my discussion of MISO auction prices in that case, stated that:

> …the results of the MISO PRA do not represent reliable capacity values to replace the Medium Four. The MISO PRA is a residual market and does not represent a permanent supply that can be relied on to meet customer demands. The MISO PRA is a market designed to enable the monetization of excess capacity created by the

[20] Ex MEC-71 (MEC-CE-033(c)).
[21] *Id.*

> uncertainty of load growth and the historically lumpy nature in which capacity additions occur in the utility industry.[22]

Thus, witness Clark appears to agree with me that the MISO PRA price is not the appropriate measure of capacity value. However, the Company's future capacity value in this current case (75 percent of CONE) was justified by citing MISO PRA prices.

Q. Even if the MISO price were a useful value for capacity, is it reasonable to assume that Zone 7 will clear at CONE in three of every four years?

A. No. As noted above, in the 2020/21 Planning Resource Auction the clearing price for MISO 7 was CONE. This resulted from the number of MWs being committed in Zone 7 falling short of the local clearing requirement (LCR) – the amount of capacity that MISO specifies must come from within the zone. But the structure of MISO's capacity market is such that extreme low or high prices occur if the MISO requirement is exceeded or not met, respectively. In the 2020 auction, Zone 7 was short its required 21,850.7 MW local clearing requirement (LCR) by only 123 MWs—or 0.6 percent of the required amount.[23] This slim shortage in Zone 7 was the result of the confluence of several factors, in addition to the amount of capacity that was available in Zone 7. Such a slim margin could be overcome if these factors were to improve. In other words, the high clearing price in the 2020 auction is not reflective of a trend that is likely to continue.

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[22] Case No. U-20165, Clark Direct, 7 TR 952. Reference to the "Medium Four" refers to Campbell units 1 and 2 and Karn units 1 and 2.
[23] Ex MEC-72 (MISO PRA results 2020/2021).

First, the capacity import limit (CIL) has been lower in Zone 7 in the past two auctions than it was in previous auctions. The CIL is the amount of capacity that a given zone can import from the rest of MISO. An increase in CIL directly reduces the amount of capacity needed inside that zone—its local clearing requirement (LCR). If the CIL for Zone 7 were to increase, then the LCR would decrease by that amount and be easier to meet. The Commission previously anticipated that Zone 7 might not meet its LCR in the 2020 PRA, and asked MISO about the potential to increase the CIL between 500 and 1500 MW.[24] The fact that this issue is being investigated, and potentially will be mitigated, makes it less likely that the LCR will not be met in the future.

Second, a recent MISO rule change called the "Long Term Outage Policy" disqualified 337.3 MWs in Zone 7 from participating in the 2020/21 PRA.[25] If these MWs had been able to participate, Zone 7 would have had a surplus. As a result, the clearing price in Zone 7 would have been drastically lower—indeed most zones cleared at $5 per MW-day (or approximately at 2 percent of CONE) rather than 100 percent. This policy was approved just a few months before the 2020/21 PRA was conducted, and generators may have had difficulty adjusting to the new policy. Now that the policy and its impact are known, utilities in Zone 7 can plan outages accordingly to avoid generator disqualification in future auctions.

[24] Ex MEC-73 (letter from Michigan PSC to MISO, Nov. 7, 2019, and Michigan Capacity Import/Export Limit Expansion Study Update, May 19, 2020).
[25] Ex MEC-74 (Resource Adequacy Subcommittee (RASC) Meeting, Item 03a – PRA results, May 6, 2020. FERC approved the MISO rule change on January 30, 2020 (Docket Nos. EL19-102-000 and ER20-129-000), available at https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=15455483.

Q. Did Commission Staff recently evaluate the extent to which Michigan will need capacity in MISO?

A. Yes. Commission Staff issued a report on March 27, 2020, which looked at the future capacity of MISO capacity for Michigan, including projections of capacity shortfall and surplus.[26] The Staff predicted a surplus in Zone 7 for the 2023/24 auction, and a negative LCR position for the next two auctions (2021/22 and 2022/23).[27] However, there is reason to think that these shortfalls may not materialize. First, as mentioned above, MISO might take steps to increase the CIL. Second, the proposed extension of a power purchase agreement (PPA) would increase the available capacity within Zone 7 for the 2021/22 planning year, if approved. Consumers has a PPA with the Palisades Power Plant (owned by Entergy), which has 780 MWs of capacity.[28] Currently, this capacity would not count towards the LCR in Zone 7 for the next auction because the contract expires in April of 2022.[29] With that in mind, Consumers filed an application with the Commission for a 51-day extension of this contract—through May 31, 2022—so those MWs could be available for the next auction for 2021/22.[30] If this contract extension is approved and Staff's projections of LCR did not include that capacity, then Staff's predicted shortage in the 2021/22 would instead become a surplus.[31]

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[26] Ex MEC-75 (Case No. U-20590, March 27, 2020, MPSC Staff, Capacity Demonstration Results: Planning Year 2023/24).
[27] *Id.*, Figure 1, p. 5.
[28] Ex MEC-76 (Case No. U-20734, Direct Testimony of David Ronk, p. 6, line 8).
[29] Case No. U-20734, Application, p.3.
[30] *Id.*
[31] It is very likely that the Staff report in Case No. U-20590 does not include any ZRCs attributable to Palisades for the 2021/22 planning year. The Staff report relies, in part, on capacity demonstration filings made by the utilities, *see* Ex MEC-75, p. 2 (noting that Staff

Q. Are bilateral contracts for capacity an indicator of capacity value?

A. Yes. The MISO PRA prices are extreme: zonal prices can be near the floor if the area is slightly over capacity <u>or</u> reach the maximum, i.e. CONE, if there is a slight shortage. If relying on PRA prices, one would conclude that all of the capacity in a zone is either worth close to nothing or the highest possible value, depending on the year. A bilateral contract is a better indicator of the value of capacity because both the buyer and seller have to agree upon a value. In 2017, the Company held a reverse auction for contract capacity where the final price was 56 percent of CONE.[32] Similarly, in the 2018 rate case, the Company claimed the costs of replacing capacity at the Karn coal units was 57.5 percent of CONE.[33] In the recent filing for its extension of the Palisades PPA, the Company used a capacity value of 10 percent of CONE; but this is based on the 2019/2020 MISO auction price and the price would only apply for a 51-day period.[34]

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received capacity demonstration filings from Consumers and other utilities, and subsequently audited those filings), and Consumers has confirmed that its projection in Case No. U-20590 does not include capacity from Palisades for 2021/22. Ex MEC-77 (MEC-CE-1009(b)); see also Ex MEC-76 (Ronk Testimony, p. 10) ("Of the 794 ZRCs assumed to be reduced in Planning Year 2021, 780 ZRCs are attributed to the Palisades Plant"). Note also that in Staff's report, there is a notable drop of 655 MWs in capacity from PPAs shown on line 7 of Figure 1 between the 2020/21 and 2021/22 auctions.

[32] Case No. U-20165, Ex MEC-16, available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000003107sAAA.

[33] Case No. U-20134, Ex MEC-55, available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000031Eq3AAE; see also U-20134, Blumenstock Cross, 5 TR 1481-84.

[34] Ex MEC-76 (Case No. U-20734, Ronk Direct, p. 9, lines 5-11).

Q. What did you assume for the capacity value for Campbell units 1 and 2?

A. In this case, I assume 60 percent of CONE as a capacity value. This is lower than Consumers' projection (75 percent CONE), higher than the cost of bilateral capacity in previous years (56 percent of CONE), and substantially higher than the average Zone 7 price in the past five auctions (28 percent of CONE).[35]

B. <u>Costs and Value of Campbell 1 and 2</u>

Q. How did you determine the costs of Campbell units 1 and 2?

A. Like any coal-fired generating unit, Campbell 1 and 2 have both fixed and variable costs. The variable costs are already accounted for in Consumers' net energy values (NEVs) concept.[36] For fixed costs, my primary source are the units' revenue requirements, which include the following components:

- Rate of return and income taxes, excluding Classic 7 costs[37]
- Annual depreciation[38]
- Property taxes[39]
- Fixed operations and maintenance[40]

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[35] Supra note 17; average % of CONE for Zone 7 in planning years 2016/17 through 2020/21. Therefore, this includes the latest 100% CONE result in 2020/21.
[36] Exs MEC-70 (MEC-CE-32-Hugo_ATT_2 (NEVs for 2015-2019) and MEC-CE-032(g)(ii) (projected NEVs for 2020-2021)). If one were to show total revenue requirements (fixed and variable), they would have to show gross energy revenues instead of the NEV, which subtracts variable costs. If this were done, both the costs and value shown in Figure 1 below would increase by the same amount (the variable costs) and the difference between the total costs and value would remain the same as what is currently shown below in Figure 1.
[37] See Ex 78 (MEC-CE-1370-Hugo-ATT_1). The Classic 7 coal units (Cobb 4-5, Weadock 7-8, and Whiting 1-3) retired in April 2016.
[38] See MEC-CE-528 Att 1.
[39] See MEC-CE-1372-Hugo_ATT_1 through ATT_7.
[40] Ex MEC-79 (Campbell 1&2 fixed O&M).

The actual revenue requirements for Campbell 1 and 2 include decommissioning costs at the Classic 7 units, which were allocated across the Company's other coal-fired units as well.[41] However, because I only want to present costs related directly to Campbell Units 1 and 2, I asked the Company for revenue requirements excluding the costs associated with the Classic 7. In response, the Company provided updated revenue requirements without the Classic 7 costs from 2017 through 2021.[42]

Q. How do the costs of Campbell units 1 and 2 compare to their energy and capacity value?

A. Ideally, the variable and fixed costs should not outweigh the energy and capacity value that the units provide. However, the costs of Campbell 1 and 2 have exceeded the units' energy and capacity value in past years and will continue to do so in 2020 and 2021—even assuming a high capacity value of 75 percent of CONE. The costs and values of the two units are combined in my analysis because Consumers did not provide revenue requirements separately by unit.[43]

Figure 1 below shows the fixed cost revenue requirements compared to the total value provided by the units—assuming three different capacity values: 1) the MISO PRA price (triangles), 2) 60 percent of CONE (circles), and 3) 75 percent of CONE (squares).[44]

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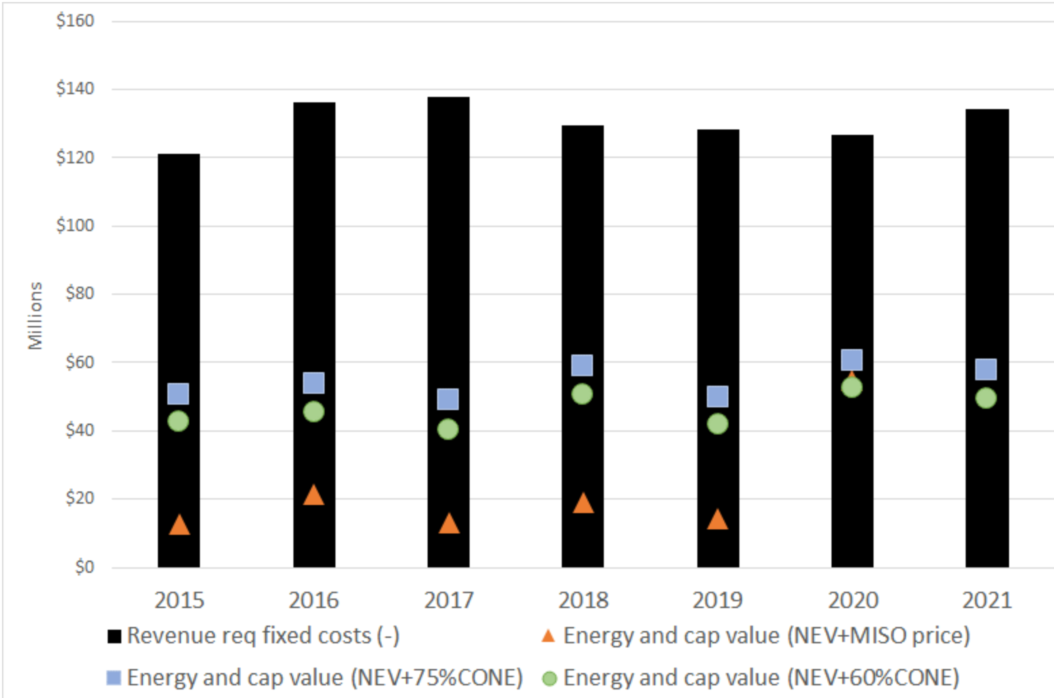
[41] *See* Case No. U-17652, May 14, 2015, Order Approving Settlement Agreement, p. 4.
[42] Ex MEC-78 (MEC-CE-1370 and MEC-CE-1370-Hugo-ATT_1).
[43] See MEC-CE-528 and MEC-CE-529.
[44] I translated MISO PRA results and CONE values from planning year into calendar year; for instance, the 2020 calendar year value is 5/12*2019/2020 price + 7/12*2020/2021 price. Capacity values of 60% and 75% of CONE use the CONE value for Zone 7 for the corresponding planning year. See Ex MEC-72 and supra note 17.

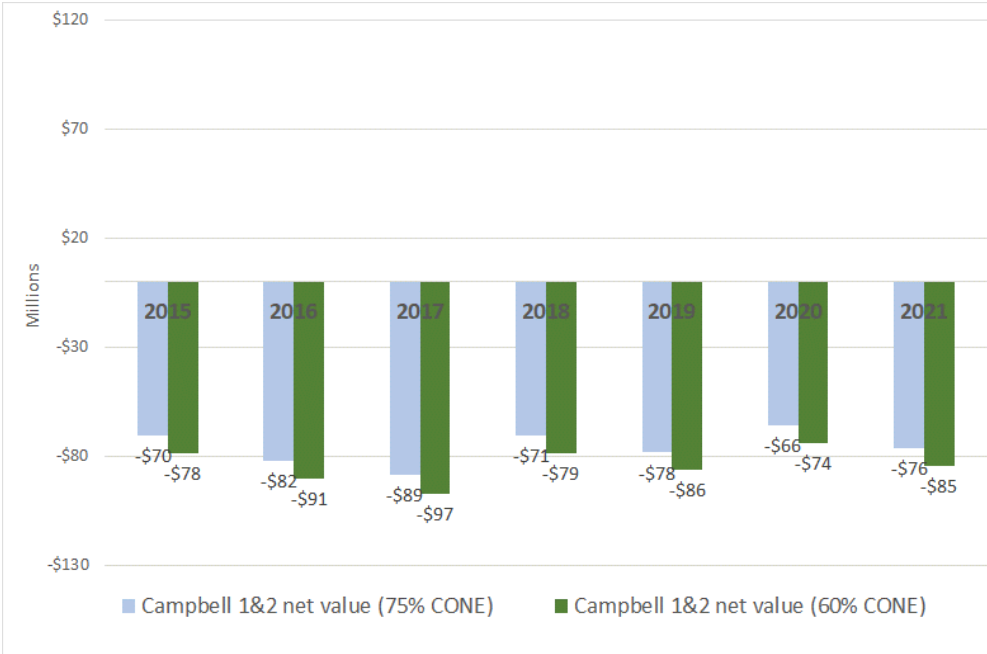
Figure 1: Comparison of Costs, Energy and Capacity Value of Campbell Units 1 and 2



Q. How much more are ratepayers paying for Campbell units 1 and 2 relative to their energy and capacity value?

A. The cost of the units far exceeds the market value of energy and capacity that they provide—as shown below in Figure 2. This figure shows the net energy and capacity value of the units (for both 60 and 75 percent CONE capacity value) minus their fixed cost revenue requirements.

Figure 2: Net Value of Campbell Units 1 and 2 (Revenue Requirements)



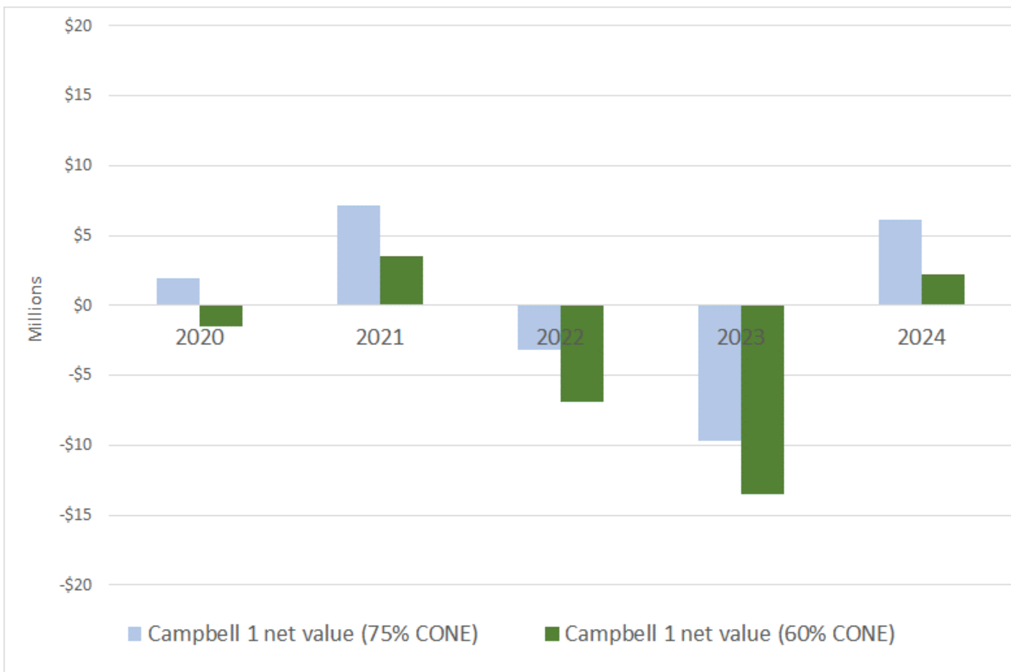
As Figure 2 shows, the energy and capacity value of Campbell 1 and 2 is far outweighed by the units' fixed costs. This is true regardless of whether one assumes a capacity value of 60% or 75% of CONE. By this measure, the "net" value of the units is between -$66 million to -$97 million annually. Put differently, Campbell 1 and 2 are costing the Company's customers more than $60 million each year compared to the units' value.

Q. Did you also look at net value of the units compared to future fixed cost spending?

A. Yes. As an illustrative exercise, I compared the future spending on fixed cost components (capital expenditures, fixed O&M, and property taxes) in terms of annual dollars spent by the Company, not revenue requirements (which were not available after 2021). Because the capital costs are included as-spent, rather than how they would be recovered in rates, the costs fluctuate up and down more than revenue requirements.[45]

The net values are shown below for Campbell 1 (Figure 3) and Campbell 2 (Figure 4) for 2020 through 2024. These show that in most years, with the 60 percent CONE capacity value, the estimated value of these units will be lower than the projected annual spending.

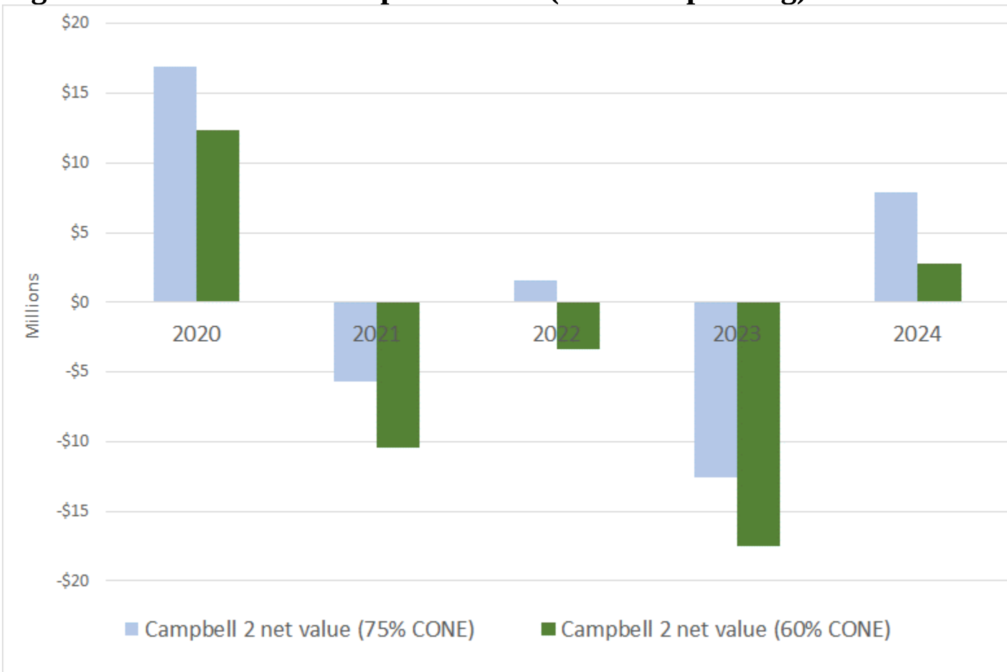
Figure 3: Net Value of Campbell Unit 1 (Annual Spending)[46]



[45] Consumers has confirmed that all capital expenditures at its coal units are financed (i.e., recovered over time, while earning a return on and of equity), rather than expensed. Ex MEC-80 (MEC-CE-535).

[46] Capital spending is from MEC-CE-543 Att 5. Property taxes for 2022-2024 were estimated using the 5-year compound annual growth rate (CAGR) from 2016-2021 values provided. Capacity value was escalated at 2.5% per year. NEV is based on the 5-year average reported from 2017-2021, adjusted for inflation by 2.5% per year.

Figure 4: Net Value of Campbell Unit 2 (Annual Spending)



Q. How should both comparisons of costs and value influence decision-making on these units?

A. Neither comparison is meant to take the place of a rigorous, forward-looking economic assessment. The comparisons above are evidence that the units' costs exceed their value to customers. The revenue requirements (Figure 1) is the more meaningful comparison because these are the costs actually paid by ratepayers,[47] and because revenue requirements are the measure used in forward-looking economic assessments. However, I recognize that these include costs that are "sunk." These sunk costs are unavoidable in the future, namely capital investments that have already been made and which are likely to be recovered in rates—regardless of when the units retire. In addition, because Consumers did not provide unit-level revenue requirements information, I was unable perform this comparison for each unit

[47] As discussed above, this comparison excludes costs associated with the Classic 7 decommissioning.

separately. The annual spending comparison included unit-specific spending and value but was limited by only looking at costs (as-spent) and value through 2024. It also does not capture how these costs would be recovered in rates—as a revenue requirement. Thus, this comparison was included for illustrative purposes.

I do not expect Consumers to have had perfect foresight, nor do I expect the Company to decide to retire one or both units based only on their recent performance. Instead, both comparisons serve as a "red flag" that should prompt the Company to rigorously evaluate these units by conducting a forward-looking analysis of revenue requirements with and without a 2024 or 2025 retirement. It is critical that such an analysis take place before incurring avoidable costs. If avoidable costs are incurred now, but the Company subsequently decides to retire the units in the mid-2020s, then ratepayers will not realize savings from those costs because they were included in rates.

Q. Should capital investment and major maintenance decisions now consider the potential for earlier retirement of Campbell units 1 and/or 2?

A. Yes. As I discussed in Section I above, Campbell 1 and 2 are currently being evaluated for retirement in the mid-2020s.[48] The more capital costs and major maintenance costs that are approved for these units in the near-term, the more costs will then become "sunk" and therefore, stranded if the units were to retire before 2031. In section III below, I discuss proposed capital investments which could be

[48] Case No. U-20165, June 7, 2019, Order approving Settlement Agreement, Par 4(a).

avoided if the units are retired in 2024, and, for the reasons explained, should be disallowed.

C. <u>The Availability of Campbell 1 and 2</u>

Q. Why is the units' availability another consideration when evaluating retirement?

A. The availability of the units affects both the energy and capacity value of the units in several respects: 1) the energy value will decrease as availability decreases (i.e., outages increase) because the units cannot generate when unavailable; 2) the capacity value will decrease as availability decreases because the units are less dependable during peak hours.

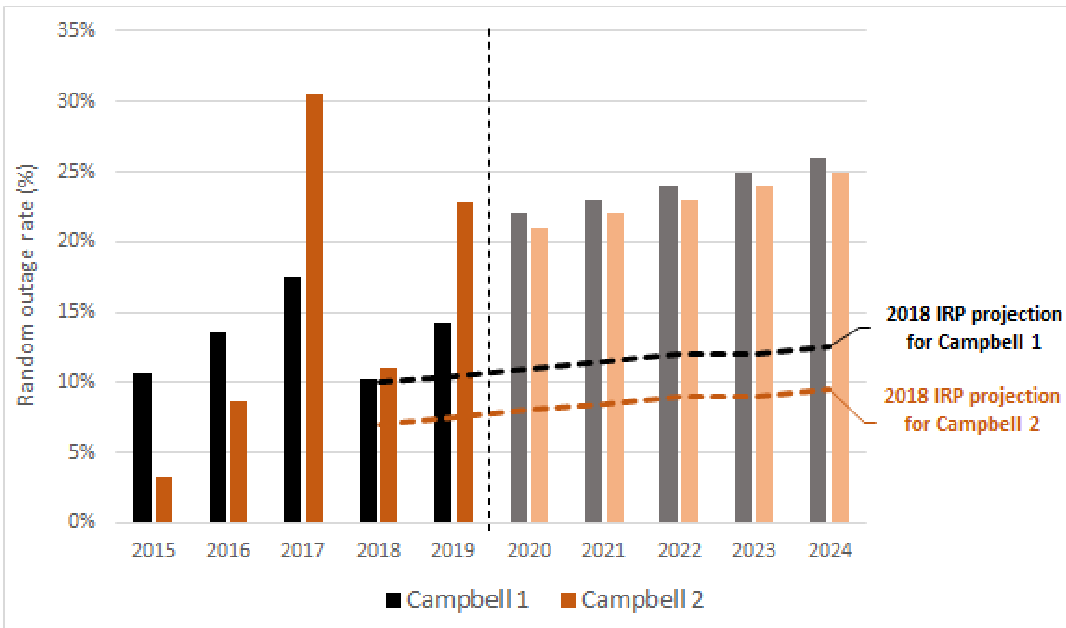
In discovery, Consumers identified the "MWh availability" of Campbell units 1 and 2.[49] This represents the maximum amount that could be generated when the unit is not on a planned or random (i.e. unplanned or forced) outage. Consumers also provided projected capacity factors for Campbell 1 and 2.[50] The capacity factor measures the actual generation of a unit as a share of its maximum capability if it ran 100 percent of the time. By definition, the capacity factor cannot be higher than a unit's availability factor because the unit cannot generate power when it is not available.

Campbell units 1 and 2 have had high random outage rates in previous years, meaning that they have been less frequently available for unplanned reasons.[51] The Company

[49] MEC-CE-1022-Hugo_ATT_1 and MEC-CE-1022-Hugo_ATT 2.
[50] *Id.*; MEC-CE-548-Hugo_ATT_1 revised. See also Ex MEC-81 (Campbell 1&2 capacity factors).
[51] MEC-CE-1022-Hugo_ATT_1 (2015-2019 actual)) and MEC-CE-1022-Hugo_ATT_2 (2020-2021); see also Ex MEC-81 (showing Campbell 1&2 random outage rates).

does not anticipate improvement in this performance through 2024[52]—as shown in Figure 5 below. For the future, the Company expects that the units will be randomly unavailable between 21 and 26 percent of the time. (This is in addition to planned outages, but those are typically scheduled for off-peak times and, therefore, do not affect capacity value.)

Figure 5: Random Outage Rates for Campbell Units 1 and 2[53]



Q. Has the Company's outlook on the availability of the units changed since 2018?

A. Yes. Shown above, in the 2018 IRP (Case No. U-20165), the Company had projected much lower random outage rates for 2019: 10.5 percent for Campbell 1 and 7.5 percent for Campbell 2.[54] In the 2018 IRP, the Company conducted a retirement analysis for the Campbell units using these optimistic assumptions about the units' future operations. But as shown above, the actual random outage rates for Campbell

[52] Ex MEC-81.
[53] *Id.*
[54] Case No. U-20165, Ex MEC-60 (20165-MEC-CE-18 +ROR 2018 IRP).

1 and 2 in 2019 were 14 and 23 percent, respectively.[55] Thus, Campbell 1 and 2 were forced out of operation between 1.3 and 3 times as much as assumed in the Company's most recent retirement analysis. An updated retirement analysis should include a realistic outlook of the units' performance.

Q. Have the Company's expectations of the random outage rate changed since the forecasts from 2018?

A. Yes. The Company now expects Campbell 1 and 2 to be far less reliable than it expected in the 2018 IRP—as shown above. From 2020 through 2024, the Company's projected random outage rate is at least twice what had been assumed previously. Thus, the Company contends that the units are at least twice as likely to be out of commission for unplanned reasons.

Q. Do random outages affect the units' energy and capacity value?

A. Yes, random outages affect both. All else equal, a forced outage lowers energy value because the unit is out and not producing energy. The same is true of a forced derate, in which the unit's capacity is restricted due to a malfunction or similar problem. A higher random outage rate would also reduce the capacity value because the zonal resource credits (ZRCs) are based on unforced capacity (UCAP).

Q. Are the Company's projections of unit generation reasonable in light of these high random outage rates?

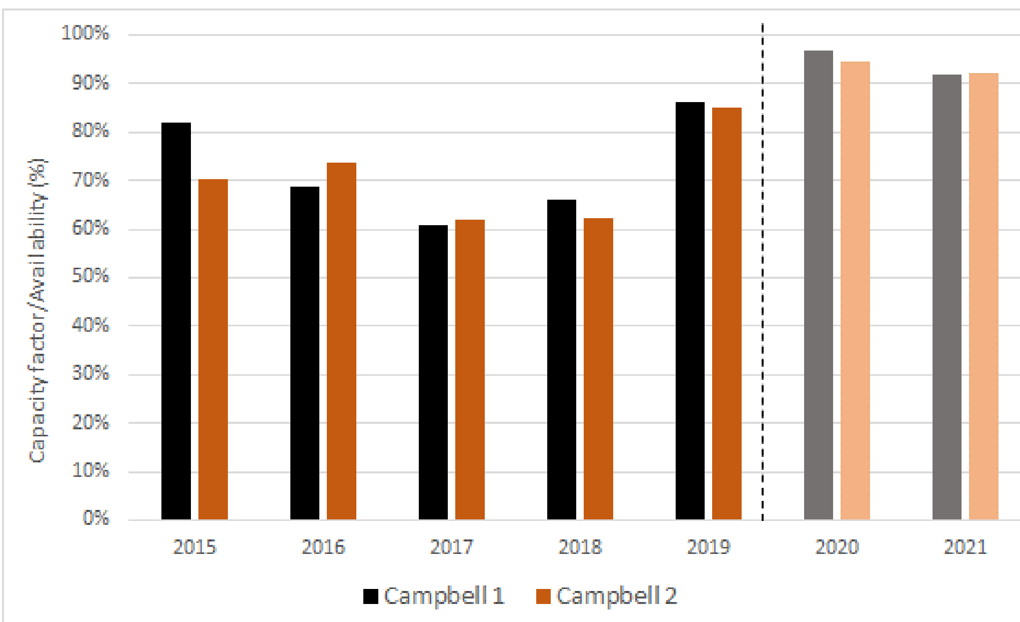
A. No. In 2020 and 2021, the Company is assuming that the two units will operate between 92 and 97 percent of their capacity when they are not on a planned or

[55] Ex MEC-81 (historical and projected random outage rates).

unplanned outage.[56] I calculated this by taking the capacity factor divided by the "MWh availability" factor.

Compared to the units' past performance—shown below in Figure 6—the Company's assumption that the units will run almost all the time that they are available in 2020 and 2021 is thus overly optimistic. If Consumers had assumed a more reasonable (lower) capacity factor that did not assume the units would be running at close to maximum when available, the units' projected net energy value for 2020 and 2021 would be lower.

Figure 6: Share of Generation from Campbell Units 1 and 2 When Available (Capacity Factor / Availability)

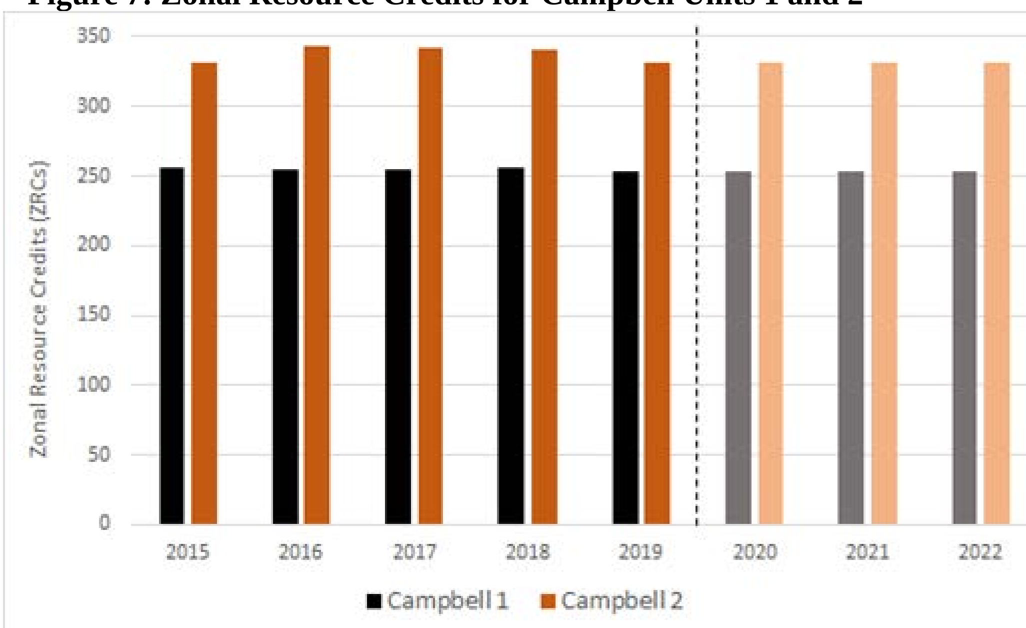


[56] MEC-CE-1022-Hugo_ATT_2.

Q. Given the expected increase in random outages, is the Company projecting a decrease in ZRCs?

A. When estimating the capacity value, the Company assumes that ZRCs in 2015 are nearly identical for the units for 2020, 2021, and 2022—as shown below in Figure 7. It is unclear if the Company's assumed ZRCs reflect the recent increase in the Campbell units' projected random outage rates. If such an impact on the ZRCs was not included, then the Company's and my estimates of capacity value are both overstated.

Figure 7: Zonal Resource Credits for Campbell Units 1 and 2[57]



Q. What do you recommend regarding the future of Campbell units 1 and 2?

A. The continued unavailability of Campbell units 1 and 2 strengthens my conclusion above that the units should be seriously considered for retirement in 2024 or 2025 based on their net value to ratepayers. A retirement decision should be based on a

[57] Ex MEC-71 (MEC-CE-033-Hugo_ATT_1).

rigorous, forward-looking assessment of the units' value relative to replacement options. This assessment should incorporate more realistic underlying assumptions as to the units' availability than what the Company had assumed in its previous retirement assessments of the units. It should also account for the impacts of decreased availability on capacity and energy value, compared to what the Company has presented in this case.

III. <u>COST RECOVERY OF SELECT CAPITAL AND MAJOR MAINTENANCE PROJECTS AT THE CAMPBELL UNITS SHOULD BE DISALLOWED.</u>

Q. Please summarize your evaluation of capital and major maintenance costs at the Campbell units.

A. In reviewing the Company's proposed capital and major maintenance spending on the Campbell units for the 2021 test year, I have determined that rate recovery of some of the proposed spending at the Campbell units should be disallowed because it has not been justified by the Company or because it is an imprudent, avoidable expense. Specifically, I am recommending disallowances of the following types of expenditures:

1. Capital and major maintenance expenditures that are avoidable if Campbell units 1 or 2 retire in 2024. This includes expenditures that the Company has identified as avoidable, as well as for projects being performed for economic reasons [[[redacted]]].
2. Capital and major maintenance projects planned for 2021 that do not have adequate supporting documentation.

3. Capital projects whose supporting documentation is inconsistent with the Company's proposed capital expenditures for 2021.

I describe the projects that fall under each of these reasons, including when a project should be disallowed for multiple reasons.

A. Avoidable capital and major maintenance expenditures

Q. How did the Company determine "avoidable" and "unavoidable" capital and major maintenance costs?

A. Under the settlement agreement from the 2018 IRP case, the Company was required to identify capital and major maintenance expenditures that could be avoided if Campbell units 1 and/or 2 retired in 2024 or 2025.[58] In discovery responses provided in this case, the Company stated that there are three main categories of capital and major maintenance projects: 1) "safety, compliance and regulatory," 2) "equipment condition," and 3) "economic."[59] Consumers suggested that the first two types are unavoidable because they are:

> …needed to maintain functionality and reliability of critical equipment, to address equipment known to be in a degraded condition, and to maintain compliance with regulatory/ environmental requirements.[60]

In a subsequent discovery response, however, the Company acknowledged that some "equipment condition" projects can be avoidable.[61]

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[58] Case No. U-20165, June 7, 2019, Order approving Settlement Agreement, Par 6.
[59] Ex MEC-82 (MEC-CE-044(a)(i)) and MEC-CE-045(a)(i)).
[60] *Id.*
[61] Ex MEC-82 (MEC-CE-1014(c)) ("The projects which were deemed avoidable were primarily related to equipment condition.").

For "economic" projects intended to improve unit performance and thereby provide savings to ratepayers, the Company stated that:

> Economic projects were reevaluated based on the retirement date scenario, and a project was identified as avoidable if the project did not offer continued economic customer benefits.[62]

The Company uses its own financial models of the internal rate of return (IRR) and present value ratio (PVR) analyses to assess these benefits.[63] Both measures look at future savings and costs of the project.

Q. Please describe generally how you reviewed the Company's designated unavoidable projects?

A. I reviewed projects to determine if there was supporting documentation for why they are unavoidable, especially for projects that involved large amounts of spending (above $100,000). Where Consumers provided an economic assessment (such as IRR) for a project, I reviewed that underlying analysis. In addition, I reviewed the cost estimates for these projects over time to see if they were consistent.

Q. How did you determine whether "economic" projects were avoidable?

A. I looked at whether these "economic" projects provided savings to ratepayers by the time of the unit's potential retirement. The earliest year that the Company will evaluate for retirement of Campbell 1 and 2 is 2024. If an "economic" investment [[[redacted]]] – that project is avoidable. Additionally, to the extent the

[62] Ex MEC-82 (MEC-CE-044(a)(i)) and MEC-CE-045(a)(i)).
[63] Hugo Direct, p. 35.

Company pursues "economic" projects at the Campbell units, those projects should have a supporting analysis that includes an up-to-date net present value, IRR, or PVR analysis with well-documented assumptions and methodology.

Q. Did the Company identify any capital and major maintenance costs at Campbell units 1 and 2 that would be avoidable with 2024 retirement of the units?

A. Yes, in Exhibits A-69 Revised and A-71, the Company identified several test year expenditures that could be avoided by the Campbell units' retirement in 2024. The Company has identified four capital projects and seven major maintenance projects whose spending in 2021 could be avoided if the units were to retire in 2024. This amounts to $1,732,000 in avoidable capital spending and $672,000 in avoidable major maintenance spending (both shown in Exhibit MEC-83).

Q. Given the questionable economics of Campbell 1 and 2, should these avoidable costs be included in rates?

A. No. As explained above in Section II, the costs of Campbell 1 and 2 substantially exceed the units' energy and capacity value, and there are serious questions about the units' economics and future performance. Because the Company has not shown that the units should operate after 2024, and because these expenditures could be avoided with a 2024 retirement, recovery of these costs should be disallowed as unreasonable and imprudent.

In addition, two of these four capital projects have substantial costs planned for 2022: $1.325 million for project 5537 and $3.49 million for project 5589.[64] If the

[64] MEC-CE-545-Hugo_ATT_1, lines 18 and 40. See also Ex MEC-85. This Exhibit is a modified version of MEC-CE-545 ATT 1, which lists planned capital expenditures at the Campbell plant for each of the years 2021-24, and identifies expenditures at Campbell 1&2

Commission agrees that the 2021 costs for these projects should be disallowed, then the Company should be cautioned that this 2022 spending would not be allowed in a future rate case.

Q. Do the costs above account for all of the avoidable spending identified by the Company with 2024 retirement?

A. No. In total, for 2021 through 2024, Consumers has identified \$44.15 million in avoidable capital spending and \$3.25 million in avoidable major maintenance at the two units.[65] Thus, over \$47 million in projected spending at Campbell 1 and 2 could be avoided if the units were to retire in 2024. A forward-looking economic assessment of the units should exclude such costs in that retirement scenario.

Almost all "economic" projects were deemed unavoidable by Consumers. However, the Company also stated that it did not re-evaluate any of these economic projects assuming a 2024 or 2025 retirement.[66] None of the avoidable costs identified by

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that would be avoidable under a 2024 or 2025 retirement. Because information about the Campbell units' projected expenditures was included in several different discovery attachments, I consolidated this information into this Exhibit, which:

-- lists the approval criteria Consumers identified for these planned expenditures (from MEC-CE-1014 ATT 1);

-- identifies projects planned for the 2021 test year that Consumers has acknowledged could be deferred beyond the test year (from ST-CE-265 ATT 1); and

-- identifies supporting documents for these planned expenditures (provided by Consumers in MEC-CE-35 ATT 2nd Revised and MEC-CE-1017).

In creating this Exhibit, I omitted projects that were listed in MEC-CE-545 ATT 1, but which did not have any projected spending in any of the years 2021-24.

I also created a similar spreadsheet for planned major maintenance expenditures, using information from MEC-CE-544-Hugo_ATT_1, MEC-CE-1015 ATT 1, ST-CE-265 ATT 1, MEC-CE-35 ATT 2nd Revised, and MEC-CE-1018. See Ex MEC-86.

[65] MEC-CE-545-Hugo_ATT_1 (identifying avoidable capital costs); *(*MEC-CE-544-Hugo_ATT_1 (identifying avoidable major maintenance costs). See also Exs MEC-85, 86 (presenting data provided by Consumers in MEC-CE-545 ATT 1 and MEC-CE-544 ATT 1).

[66] Ex MEC-82 (MEC-CE-1014(c)).

Consumers were "economic" projects with the exception of project 5589 but the Company stated that it has not done an economic analysis for that project.[67]

Q. Did you find other projects that were avoidable with 2024 retirement, even though the Company did not identify them as such?

Yes. There are two projects categorized by Consumers as unavoidable that, after reviewing the supporting analyses, I determined were in fact avoidable with 2024 retirement.

Q. Please explain why Project 5462 is avoidable.

A. Project 5462 (called "JHC2 SAH Replace baskets and seals") is an "economic/equipment condition" project that the Company estimates will cost $2.425 million in 2021 and is intended [[[redacted]]], Consumers prepared an internal rate of return (IRR) analysis for this project.[69] [[[redacted]

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[67] Ex MEC-82 (MEC-CE-1014(a)-(b)).
[68] Ex MEC-87C (MEC-CE-1013(d)(i) CONF and MEC-CE-1027(e)-CONF).
[69] Ex MEC-87C (MEC-CE-1027(a)-(b)-CONF); see also MEC-CE-35 Att 12 2nd revised, "2020-24 Revised Capital" tab.
[70] U20697-MEC-CE-035-Hugo_CONF_ATT_4 (IRR workpaper). [[redacted]]] Ex MEC-87C (MEC-CE-1027(f)-CONF).
[71] *Id*. [[[redacted]]]

[redacted].]]

Cost recovery for the project should be disallowed on this basis alone. But there are two additional reasons to disallow this project: [[[redacted]. [redacted]]].

[[[redacted].]][75]

For all of the reasons above, this $2.425 million expenditure should be disallowed.

Q. Please explain why Project 9950 could be avoidable.

A. Project 9950 (called "JHC2 LP Turbine Component Replacement") will cost an estimated $3.3 million in 2021.[76] Consumers has identified this as an "economic/equipment condition" project,[77] which is [[[redacted]

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72 Ex MEC-87C (MEC-CE-1027(a))-CONF).
73 Ex MEC-87C (MEC-CE-1027(a), (b), (d))-CONF).
74 MEC-CE-035-Hugo_CONF_ATT_4, [[[redacted]]].
75 Ex MEC-87C (MEC-CE-1027(c)(ii) CONF).
76 Hugo WP-SAH-22 revised; see also Ex MEC-85, page 6; Hugo Direct, p. 55.
77 Ex MEC-85, page 6 (the Company identified the project's approval criteria as "Economic & Equipment Condition" – underlying source is MEC-CE-1014-Hugo_ATT_1, cell J127).

[redacted].]][78] An IRR/NPV analysis was conducted by the Company to support its pursuit.[79] However, the Company's analysis showed the [[[redacted]]].[80] As with project 5462, the Company cannot identify [[[redacted].]]

The Company has provided confusing and inconsistent responses about the rationale for this project. When specifically asked if this project was considered an economic project for evaluation purposes, the Company confirmed that it was.[83] However, the Company has separately claimed that the project may not be deferred due to safety reasons.[84] If this project is, in fact, needed for safety reasons, then it should not be disallowed. However, on the present record there is a contradictory and insufficient basis to award cost recovery for this project.

For all of the reasons above, this $3.3 million expenditure should be disallowed. Combined with project 5462 above that is $5.725 million in additional avoidable capital spending in 2021.

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[78] Ex. MEC-89C (MEC-CE-1026(d)-CONF);
[79] MEC-CE-35 Att 12 2nd revised, "2020-24 Revised Capital" tab; Ex. MEC-90 (MEC-CE-1012(d)(i)).
[80] fos2019 - LP Turbine CONF, [[[redacted]]].
[81] Ex. MEC-89C (MEC-CE-1026(b)-CONF).
[82] *Id.*
[83] Ex. MEC-90 (MEC-CE-1012(d)(i)).
[84] Ex. MEC-91 (MEC-CE-1020(a)).

[redacted]

A. [redacted].]]

B. <u>Proposed expenditures at the Campbell plant that lack supporting documentation or contain inconsistent cost estimates</u>

Q. Have you identified any other problems with the capital and major maintenance expenditures planned for the Campbell plant?

A. Yes. In reviewing Consumers' proposed capital and major maintenance spending at Campbell in the 2021 test year, I found that many of these proposed projects lack adequate supporting documentation. These include projects at Campbell units 1 and 2, projects at Campbell unit 3, and a few plant-wide projects.

Q. Please elaborate.

A. Consumers has provided insufficient or inconsistent documentation for many large expenditures that it is requesting to include in rates. The Commission has recognized the need for documentation supporting generation-related capital expenditures. In a recent Order in the DTE rate case, No. U-20561, the Commission disallowed rate recovery of spending where there was a lack of supporting information.[85] In reviewing Consumers' capital and major maintenance projects at Campbell, I have found many that lack sufficient support in the following respects:

1. The project had little to no documentation.
2. The Company acknowledged that it did not have supporting documents, indicating that it planned to conduct an economic analysis of the project in the future (i.e., after the record in this case has closed).
3. The cost estimates for the project were seriously inconsistent.

Q. What is your recommendation for these expenditures proposed for the 2021 test year?

A. I recommend that the Commission disallow rate recovery of these capital and major maintenance costs at this time.

In identifying projects for which I recommend a disallowance, I limited my focus in two respects. First, with one exception, I only included projects where the projected spending was over $100,000 in 2021.[86] Second, I only included projects which the

[85] Case No. U-20561, May 8, 2020, Order, pp. 40-44, 46, 48-57.
[86] The only poorly documented project I recommend disallowing recovery of that is below this cost threshold is project 5689 ("JHC3 Install Boiler Slag Reducing Coating Front and Rear Walls"). This project extends over a two-year period, with a projected cost of only $53,000 in 2021, but $889,000 in 2022.

Company has stated could be deferred beyond the 2021 test year. In response to a Staff discovery request, the Company has identified which 2021 test year expenditures at the Campbell plant could be deferred.[87] Projects above this spending threshold, that the Company acknowledges were deferrable, and that met one or more of the criteria listed above are listed in Exhibit MEC-83.

Q. Please describe how you determined that projects had insufficient supporting documentation.

A. In reviewing the filing and data responses, I found instances of more than $100,000 of planned 2021 spending, which was designated as deferrable by the Company, and had no supporting documentation. In discovery, we requested supporting documentation for the Company's planned capital and major maintenance expenditures. Although some projects have supporting documents, there are many projects planned for 2021 that do not have an IRR, PVR, project charter, scope document, or other supporting document.[88]

For some projects, Consumers offered a short explanation in a discovery attachment or in testimony.[89] But these explanations are cursory and are insufficient to support the planned expenditures. Several examples include:

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[87] Consumers has stated that projects 5481, 5482, 5537, and 8250 are not deferrable per ST-CE-265_ATT_1; therefore, these are not recommended for disallowance.

[88] Consumers has confirmed that the following capital projects do not have supporting documentation: 5480, 5481, 5482, 5537, 5543, 5545, 5594, 5663, 5689, 5691, 5693, 5707, 5746, 8250, 9650, 9651, 9653, 9654, 9671, 9690, 3089, 9655, 9656, 9692. See Ex MEC-92 (MEC-CE-1017(a), (b)); Ex MEC-88 (MEC-CE-35 (3rd Supp.)).
Consumers has confirmed that the following major maintenance projects do not have supporting documentation: 5494, 5516, 5550, 5555, 5632, 5637, 5669, 5675, 5696. See Ex MEC-92 (MEC-CE-1018(a)).

[89] MEC-CE-35 ATT 12 2nd Revised, "2020-24 Revised Capital" tab, columns K, L, and M.

- Project 5693: $1,235,000 for a mill overhaul project at Campbell 3. This project has no IRR, project charter, or scope document; this expenditure is supported by only a few lines of testimony and two sentences in a discovery attachment.[90]

- Project 5543: $696,000 for a mill overhaul project at Campbell 1. As with project 5693 (above), the Company was unable to provide any supporting documents or analyses—its support is limited to a brief description of the project in testimony and two sentences in a discovery attachment.[91]

- Project 5545: $459,000 for overhaul of the hydraulic coupling rotor at Campbell 2. This project has no IRR or scope document. The only support for this expenditure is a brief description, in a discovery attachment, stating that the problem being addressed is "to rebuild the spare Hydraulic Coupling rotor removed in 2009 for installation during 2018 periodic outage."[92]

There were also two projects (Work IDs 5707 and 5708) where Consumers acknowledged the lack of supporting documents yet stated its intent to conduct an economic analysis in the future.[93] Because they are deferrable, and it is unclear if these are cost-effective, they should be disallowed at this time. Finally, there was a project [[[redacted]

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[90] Hugo Direct, p. 61; MEC-CE-35 ATT 12 2nd Revised, "2020-24 Revised Capital" tab, cells N63, P63.
[91] Hugo Direct, p. 56; MEC-CE-35 ATT 12 2nd Revised, "2020-24 Revised Capital" tab, cells N11, P11.
[92] MEC-CE-35 ATT 12 2nd Revised, "2020-24 Revised Capital" tab, cell N39. The spreadsheet repeats this rationale in cell P39, and includes the following sentence fragment: "Eliminate risk of outage extension due to unforeseen repairs needed to".
[93] Ex MEC-82 (MEC-CE-1014(a)).

[redacted]]]: Work ID 8616. [[[redacted][94]]] Cost recovery for this project should likewise be disallowed.

Exhibit MEC-83 shows those projects that should be disallowed in this case due to lack of supporting documentation or inconsistences. In total, these projects represent $10.67 million in capital spending and $366,000 in major maintenance spending in 2021.

Q. Please summarize your recommendations for disallowance.

A. I recommend the following regarding 2021 capital and major maintenance spending:

1. Expenditures in 2021 that are avoidable if Campbell units 1 and 2 were to retire in 2024 be disallowed.
   a. For those identified by the Company, these include $1.732 million in capital spending and $672,000 in major maintenance—shown in Exhibit MEC-83.
   b. I have also identified $5.725 million in capital projects that are likely avoidable with early retirement and where the supporting analyses for these projects [[[redacted]]].
2. Expenditures in 2021 for projects at Campbell that lack sufficient documentation be disallowed at this time. These include $10.67 million in

[94] Ex MEC-93C (MEC-CE-1021(b)-CONF).

capital spending and $366,000 in major maintenance—shown in Exhibit MEC-83.

IV. INCREMENTAL COSTS FOR CAMPBELL 1 AND 2 RETIREMENT

Q. What are the "incremental costs" for retiring Campbell units 1 and 2?

A. Incremental costs are those associated with a unit's retirement. Consumers defines two categories of incremental costs for Campbell 1 and 2 retirement: i) the costs of separating the retiring units from Campbell unit 3, and ii) decommissioning activities (such as "site restoration") after the units retire.[95]

Q. Did the Company estimate "incremental" capital expenditures associated with Campbell Units 1 and 2 retiring in 2024 or 2025?

A. Yes. For instance, the Company estimates $4 million in incremental costs in 2021 at Campbell 3 if the other two units retired in 2024.[96] Currently, the Company is not requesting that these costs be included in rates but noted that these costs could be added at a later date.[97] The Company further projected incremental costs that would be incurred in subsequent years with a 2024 or 2025 retirement of Campbell 1 and 2.[98]

Q. Are these types of costs unavoidable?

A. Yes. The Company only provided "incremental" costs associated with 2024 or 2025 retirement. But such costs are not "incremental" with respect to retirement year

[95] Ex. MEC-82 (MEC-CE-044(a)(ii)).
[96] Ex A-69 (SAH-4) Revised, p. 1
[97] Hugo Direct, p.105, lines 8-14.
[98] Ex. MEC-94 (Hugo WP-23).

because they would be incurred regardless of when the units were retired—even in 2031. In discovery, Consumers has acknowledged that such costs would occur regardless of when the units retire. [99] When conducting the retirement assessment for Campbell 1 and 2, the Company's assumptions should reflect the fact that these types of costs are unavoidable.

Q. Are Consumers' projected incremental costs likely overstated?

A. Yes. The Company stated that these cost estimates were "an educated order of magnitude estimate" that assumed a "worst case scenario."[100] The Company currently has no documentation supporting these estimates,[101] nor has it estimated a non "worst-case scenario."

Q. If one were to include such costs in a retirement assessment, should they escalate with the retirement year?

A. Yes. The Company's estimates show that 2024 and 2025 incremental costs are identical, even though the spending occurs one year apart. Estimates of capital costs typically are escalated due to expected increases in costs of labor and materials in each year. The Company should escalate incremental costs based on the year they are spent.

Q. What are your recommendations on the treatment of incremental costs?

A. As I discussed above, Consumers will be evaluating different potential retirement dates for Campbell 1 and 2 in the upcoming IRP. In performing that assessment, the

[99] Ex. MEC-95 (MEC-CE-546(c)).
[100] *Id.* (MEC-CE-546(a)).
[101] *Id.*

Company should provide a more detailed incremental cost estimate that: 1) is a likely scenario (not a "worst case"), backed up by supporting documentation; 2) shows costs incurred in every retirement year scenario; and 3) increases costs with the spending year. These changes should be addressed in the Company's upcoming modeling of Campbell 1 and 2 retirement in order to prevent bias towards continued operation.

V. COMMUNITY TRANSITION PLANNING FOR KARN UNITS 1 AND 2 SHOULD BE ROBUST AND TRANSPARENT.

Q. What is the status of the Company's transition plan for the retirement of Karn units 1 and 2 in 2023?

A. The Company developed a community transition plan in 2018.[102] In the IRP case, No. U-20165, Company witness Norman Kapala provided a high-level overview of this plan.[103] Thus far, the Company [[[redacted]]] For example, whereas [[[redacted]]],[104] in this case Consumers suggests that the study will not be completed until late 2020 or 2021.[105] Consumers states it will update the community transition plan in late 2020.[106] More details about the timing and process to develop and implement the transition plan, including the future-use study, should be provided.

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[102] Ex MEC-96C (MEC-CE-53-Hugo_CONF_ATT_1).

[103] Case No. U-20165, Direct Testimony of Norman J. Kapala, 8 TR 1147-48. It is unclear [[[redacted]]]

[104] *See* Ex MEC-96C, p. 13 (MEC-CE-053-Hugo_CONF_ATT_1).

[105] Ex MEC-97 (MEC-CE-549(c)); Ex MEC-98 (MEC-CE-53(a)(ii)).

[106] Ex MEC-97 (MEC-CE-549(a)).

Q. How much money has Consumers committed to date for the transition?

A. That is not clear. The Company projects significant spending for the retention and separation program for current Karn employees,[107] but has not provided details on spending to address other retirement-related impacts. At present, it appears the Company thus far has only committed $15,000 as a contribution for an economic development grant.[108]

Q. Is the Company's transition plan publicly available?

A. No. The Company designated its community transition plan confidential and, therefore unavailable to the public and the affected community.[109] The Company has described the transition plan as "a business confidential document for Company use only."[110]

Q. Does the Company plan to engage the community as it updates the transition plan?

A. While [[[redacted]]], the Company stated in discovery in this case that it "is not consulting with community groups or community leaders in updating the plan" and "does not plan to conduct a public forum to receive input."[111]

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[107] Hugo Direct, pp.128-132.
[108] MEC-CE-549-Hugo_ATT_1 p. 8. According to the EDA grant application, Consumers verbally committed to $15,000 for economic development activities.
[109] See Ex MEC-96C (MEC-CE-053-Hugo_CONF_ATT_1).
[110] Ex MEC-99 (MEC-CE-1029(b)).
[111] Ex MEC-99 (MEC-CE-1029(a)-(b)).

Q. What do you recommend regarding the Karn retirement transition plan?

A. The Commission has emphasized the importance of transition planning, especially regarding community engagement and transparency. In the recent DTE rate case order, regarding the retirement of the River Rouge plant, the Commission directed DTE to file:

> …a comprehensive community transition plan. The plan should address public input DTE Electric has received through public meetings in River Rouge or other outreach to communicate the utility's plans with the community and receive input from community members.[112]

The Commission also noted the importance of "plans for a smooth retirement and community transition, accounting for plant employees, the impact on local tax base, site remediation, and other factors."[113]

As the Company is in the process of developing and updating its transition plan, it should recognize and incorporate the public and community interest in the transition. At a minimum, the Company should present details to the Commission and stakeholders about the transition process, including a plan for meaningful stakeholder and community engagement. I recommend that Consumers be directed to present additional details related to the Karn transition. Such information should be submitted as part of the June 2021 IRP filing, if not earlier.

[112] Commission Order, Case No. U-20561, p.189.
[113] *Id.*

VI. Conclusion and Recommendations

Q. What do you recommend to the Commission?

A. I recommend the following:

1. The Company should be required to give serious consideration to the retirement of Campbell units 1 and 2 in 2024 or 2025 by conducting, in its 2021 IRP, a robust, forward-looking assessment of the units, using realistic assumptions of the units' availability, energy value, and capacity value
2. The Commission should disallow test year capital and major maintenance costs that could be avoided if Campbell 1 and 2 retire in 2024.
3. The Commission should disallow capital and major maintenance costs that have not been adequately supported by the Company.
4. The Commission should direct Company to provide additional details on its updated Karn community transition plan when submitting the 2021 IRP. The Company should be directed to seek public and community input in updating this transition plan, and the plan should be made public.

Q. Does this conclude your testimony?

A. Yes.

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PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. *Senior Researcher*, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. *Senior Associate*, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. *Research Analyst*, *Economic Consultant*, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. *Billing Coordinator, Accounting Liaison,* 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. *Data Analyst* (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

EDUCATION

Tufts University, Medford, MA
Master of Arts in Economics, 2007

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Bachelor of Arts in Mathematics and Economics, Cum Laude, Dean's Scholar, 2002.

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Economic and Policy Analysis of Energy, Environment and Equity

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Resume dated May 2020

Question:

1. Refer to page 9, lines 10-12 and page 13, lines 6-12 of the Direct Testimony of Scott A. Hugo, and to column (f) of Exhibit A-68.

a. Please produce, in machine-readable electronic format with formulas intact, all modeling files, including input and output files, and workpapers created, used, or relied on in developing the "Actual NEV" figures presented in column (f).
b. Please identify each category of revenues factored into the calculation of the "Actual NEV" figures presented in column (f).
c. Please identify each category of costs factored into the calculation of the "Actual NEV" figures presented in column (f).
d. Please state whether each of the following categories of costs were factored into the calculation of the "Actual NEV" figures presented in column (f):
i. Capital
ii. Major maintenance
iii. Fixed O&M
iv. Property taxes
v. Any other non-variable costs and, if so, please describe such costs.
e. For each category of cost listed in subsection d that was not factored into the calculation of the "Actual NEV" figures presented in column (f), please identify the actual cost for each of the years 2014-18 for each of the Company's coal units.
f. Please identify the actual NEV for each of the Company's coal units for each of the years 2014 through 2018.
g. For each of the Company's coal units, please identify:
i. The actual NEV for 2019 (or projected NEV for any portion of 2019 where actual figures are not yet available).
(a) If the Company does not yet know the actual NEV for all of 2019, please state when this data will be available, and describe any efforts currently underway to calculate this.
ii. The Company's most up-to-date projection of the unit's NEV for each of the years 2020, 2021, and 2022.
iii. For each category of cost listed in subsection d that is not factored into the NEV, please identify the unit's actual cost (if available) or projected cost for each of the years 2019-22.

Response:

a. See attached Excel file: 20697-MEC-CE-32(a) CONFIDENTIAL.xlsx. This attachment is Confidential and is subject to the Protective Order in Case No. U-20697, and will be provided only to those persons who have signed the nondisclosure certificate pursuant to such Protective Order.

This file was created using a third party proprietary software from Power Cost Inc. This software houses MISO offers, unit output and MISO settlements data. The updated file which includes

2019 was created on March 26th, 2020 by entering the dates and units and the program calculated these values based on the MISO market settlements at that time. This is the only output from the program.

b. The revenues included in column (f) on Exhibit A-60 (JPB-3) include:
- Day Ahead Total Revenue, column (g)
- Real Time Energy Revenue, column (h)
- Real Time Ancillary Service Revenue, column (i)
- Net Regulation Generation Adjustment, column (j)
- Price Volatility Make Whole Payment, column (k)
- Revenue Sufficiency Guarantee Make Whole Payment, column (l)

c. The costs included in column (f) on Exhibit A-60 (JPB-3) include:
- Revenue Sufficiency Guarantee Penalty, column (m)
- Ancillary Service Penalty, column (p)
- Real Time Administrative Fee, column (q)
- Real Time Startup Cost, column (t)
- Real Time Energy Cost, column (u)
- Real Time Ancillary Service Cost, column (v)

d. Capital, major maintenance, fixed O&M, property taxes, and any other non-variable costs (i.e. depreciation) were not factored into this calculation.

e. Consumers Energy objects to subpart (e) of this request on the basis of relevance, as the requested costs are not data points in the calculation of NEV. Without waiving this objection, the Company states that the requested information (i.e. non-power supply revenue requirement) is not readily available in a per unit format.

f. See attached Excel file: U-20697-MEC-CE-32(f).

g.

(i) Refer to Excel file: U-20697-MEC-CE-32(f). The 2019 NEVs are based upon settlement statements for 2019 operating days through March 26, 2020.

(ii) Consumers Energy has not projected 2022 NEVs. The projected 2020 and 2021 NEVs are as follows:

2020 NEV ($)					
	Camp 1	Camp 2	Camp 3	Karn 1	Karn 2
January	2,044,360	1,885,615	7,022,784	1,607,405	1,672,680
February	880,566	1,454,708	4,567,096	801,510	1,152,074
March	-	1,521,208	4,687,980	888,169	803,969
April	-	856,156	3,118,037	782,360	854,433
May	177,864	947,635	2,905,335	534,482	730,917
June	734,608	846,599	2,402,666	199,557	635,476
July	1,017,398	1,131,948	3,703,289	368,234	805,573
August	645,623	698,131	2,415,477	541,460	579,543
September	720,689	771,329	2,782,085	638,817	662,254
October	619,516	123,498	1,058,977	525,971	174,650
November	669,578	463,686	1,506,539	640,692	66,246
December	1,069,906	1,213,016	3,815,604	432,097	1,097,346
Total	8,580,108	11,913,529	39,985,870	7,960,753	9,235,162
2021 NEV ($)					
	Camp 1	Camp 2	Camp 3	Karn 1	Karn 2
January	1,166,451	1,765,775	5,857,657	431,709	1,555,594
February	1,309,551	1,384,521	4,514,078	861,200	979,206
March	844,205	598,201	3,194,831	757,187	693,503
April	312,244	-	124,582	489,828	568,922
May	366,746	149,024	923,574	432,263	484,482
June	462,706	567,418	1,598,165	242,934	466,434
July	980,354	1,075,792	3,345,226	691,760	363,822
August	549,049	686,787	2,165,253	464,495	558,809
September	403,134	538,204	1,600,306	420,929	390,469
October	-	529,481	1,453,807	141,689	321,910
November	155,411	613,677	1,542,824	(12,850)	34,420
December	770,061	784,113	2,895,216	711,293	684,990
Total	7,319,911	8,692,991	29,215,518	5,632,438	7,102,560

(iii) Consumers Energy objects to subpart (g)(iii) of this request on the basis of relevance, as the requested costs are not data points in the calculation of NEV. Without waiving this objection, the Company states that the requested information (i.e. non-power supply revenue requirement) is not readily available in a per unit format.

Scott A. Hugo

Scott A. Hugo
April 6, 2020

Director – Generation Asset Strategy

	2014	2015	2016	2017	2018	2019	TOTAL
CAMPBELL 1	$ 27,942,447	$ 6,386,988	$ 5,963,929	$ 4,201,021	$ 8,497,680	$ 5,687,739	$ 58,679,805
CAMPBELL 2	$ 36,570,866	$ 4,339,691	$ 6,192,416	$ 2,219,726	$ 9,133,940	$ 4,809,091	$ 63,265,729
CAMPBELL 3	$ 110,182,186	$ 23,011,247	$ 19,778,737	$ 28,200,856	$ 47,291,421	$ 30,225,507	$ 258,689,954
KARN 1	$ 16,938,594	$ 4,156,481	$ 5,989,670	$ 8,176,719	$ 7,238,867	$ 1,954,120	$ 44,454,451
KARN 2	$ 25,026,209	$ 2,007,933	$ 5,981,023	$ 4,466,650	$ 6,489,054	$ 438,945	$ 44,409,813

Question:

2. Refer to Table 2, and to page 14, line 14 through page 15, line 2 of the Hugo Direct Testimony.

   a. Please explain why you would calculate the capacity value of the Company's generating units based upon CONE, rather than using (i) the settlement price reflected in the MISO Planning Resource Auction, or (ii) the estimated cost of acquiring replacement capacity.
   b. Please identify the capacity value for each of the Company's coal units for each of the years 2014-2019. (Please provide the projected capacity value in dollars for any portion of 2019 where actual figures are not yet available.)
   c. Please provide the Company's most up-to-date projection of each of the coal units' capacity value in dollars for each of the years 2020-22, including supporting assumptions for those values.

Response:

a. Table 2 includes calculations of the generating unit capacity values based upon both the Zone 7 settlement price reflected in the PRA as well as CONE. Both calculations were conducted to provide a range of reasonable values for the capacity of each generating unit. A calculation using the estimated cost of acquiring replacement energy was not performed because the Company currently has sufficient capacity.

b. See Attachment U20697-MEC-CE-033_ATT_1. All of the values are based upon ZRC values and PRA settlement price. The capacity values are based upon the following settlement prices per ZRC-year:

2014	6,114
2015	1,270
2016	26,280
2017	548
2018	3,650
2019	8,870

c. See Attachment U20697-MEC-CE-033_ATT_1. The projected capacity value is based on 75% of MISO's CONE filing from September 2019 ($94k/ZRC-yr). The Company projects a capacity price at 75% of CONE based on the premise that if Zone 7 was short on capacity, the capacity prices would hit CONE for 3 years and by year 4 a new resource would be available.

2020	70,500
2021	71,910
2022	73,348

Scott A. Hugo
April 6, 2020

Director – Generation Asset Strategy

RESOURCE	2014 CAPACITY CREDITS (ZRCs)	2014 CAPACITY VALUE	2015 CAPACITY CREDITS (ZRCs)	2015 CAPACITY VALUE	2016 CAPACITY CREDITS (ZRCs)	2016 CAPACITY VALUE	2017 CAPACITY CREDITS (ZRCs)	2017 CAPACITY VALUE	2018 CAPACITY CREDITS (ZRCs)	2018 CAPACITY VALUE
COAL FIRED										
JH Campbell 1	**257**	**$ 1,570,687**	**256**	**$ 324,739**	**255**	**$ 6,698,772**	**255**	**$ 139,466**	**256**	**$ 935,860**
JH Campbell 2	**343**	**$ 2,099,548**	**331**	**$ 420,624**	**344**	**$ 9,032,436**	**343**	**$ 187,800**	**341**	**$ 1,243,920**
JH Campbell 3	**725**	**$ 4,430,816**	**737**	**$ 935,609**	**735**	**$ 19,326,312**	**776**	**$ 425,412**	**780**	**$ 2,845,540**
DE Karn 1	**239**	**$ 1,460,023**	**243**	**$ 308,610**	**225**	**$ 5,905,116**	**241**	**$ 131,794**	**243**	**$ 886,950**
DE Karn 2	**244**	**$ 1,492,427**	**254**	**$ 321,945**	**252**	**$ 6,633,072**	**252**	**$ 138,151**	**254**	**$ 926,005**

Year	Capacity Value
2014	6,114
2015	1,270
2016	26,280
2017	548
2018	3,650
2019	8,870
2020	70,500
2021	71,910
2022	73,348

2019		2020		2021		2022	
CAPACITY CREDITS (ZRCs)	CAPACITY VALUE	CAPACITY CREDITS (ZRCs)	CAPACITY VALUE	CAPACITY CREDITS (ZRCs)	CAPACITY VALUE	CAPACITY CREDITS (ZRCs)	CAPACITY VALUE
254	$ 2,250,319	254	$ 17,885,850	254	$ 18,243,567	254	$ 18,608,388
331	$ 2,935,970	331	$ 23,335,500	331	$ 23,802,210	331	$ 24,278,188
775	$ 6,873,363	775	$ 54,630,450	775	$ 55,723,059	775	$ 56,837,365
244	$ 2,166,054	244	$ 17,216,100	244	$ 17,560,422	244	$ 17,911,582
243	$ 2,154,523	243	$ 17,124,450	243	$ 17,466,939	243	$ 17,816,229

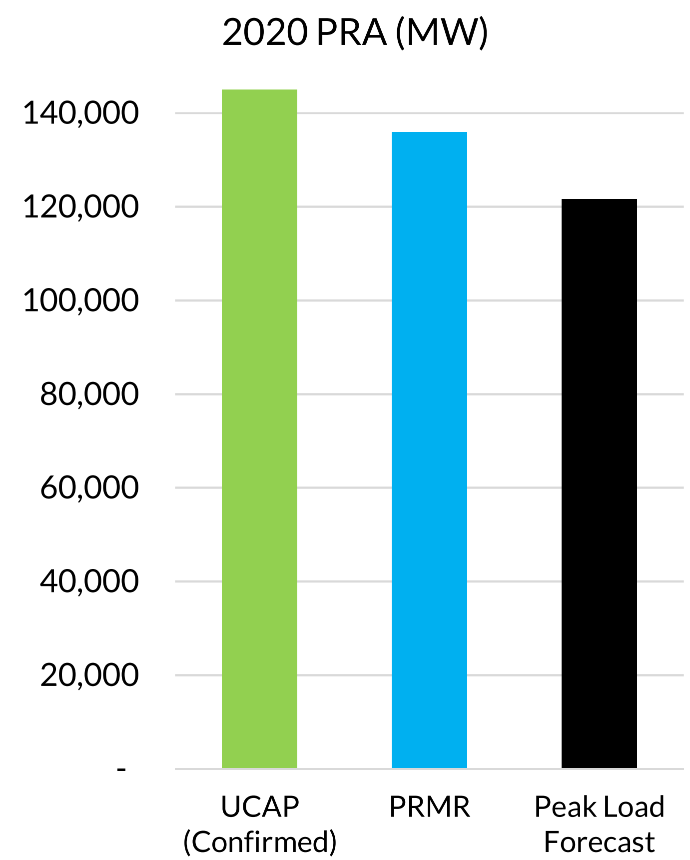
MISO

2020/2021 Planning Resource Auction (PRA) Results

April 14, 2020

MISO region has adequate reserves to meet its 136 GW Planning Reserve Requirement

- Most zones cleared **$4.75-$6.88/MW-day**
- Zone 7 (MI) cleared at Cost of New Entry of $257.53/MW-day - insufficient zonal capacity to meet Zone 7 Local Clearing Requirement (LCR)
- South to North capacity reached limit causing price separation of $0.25
- Regional generation supply consistent with the 2019 OMS-MISO Survey
- Cleared resources show the continued growth of gas, renewables, and demand side resources. This trend is the primary basis for Resource Availability and Need initiatives around the timely and efficient conversion of capacity into energy across all hours of the year



MISO's RA construct combines regional and local criteria to achieve a least-cost solution for the region

Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:

- Submit a Fixed Resource Adequacy Plan (FRAP)
- Utilize bilateral contracts with another resource owner
- Participate in the Planning Resource Auction (PRA)

The Independent Market Monitor (IMM) reviews the auction results for physical and economic withholding

Inputs

- Local Clearing Requirement (LCR) = capacity required from within each zone
- MISO-wide reserve margin requirements, which can be shared among the Zones, and Zones may import capacity to meet this requirement above LCR
- Capacity Import/Export Limits (CIL/CEL) = Zonal transmission limitations
- Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

Outputs

- Commitment of capacity to the MISO region, including performance obligations
- Capacity price (ACP = Auction Clearing Price) for each Zone
- ACP price drives the settlements process
- Load pays the Auction Clearing Price for the Zone in which it is physically located
- Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located

Three primary changes since 2019 Auction

- **Preclude Resources on Long Term Outages from Participation in the PRA (ER20-129)**

  In January 2020, FERC approved MISO's filing to limit the ability of Resources to participate in a Fixed Resource Adequacy Plan ("FRAP") and MISO's Planning Resource Auction ("PRA"), if the Resource has expected full or partial outages that last for any ninety (90) or more of the first 120 Calendar Days of the Planning Year which is consistent with the highest period of LOLE risk.

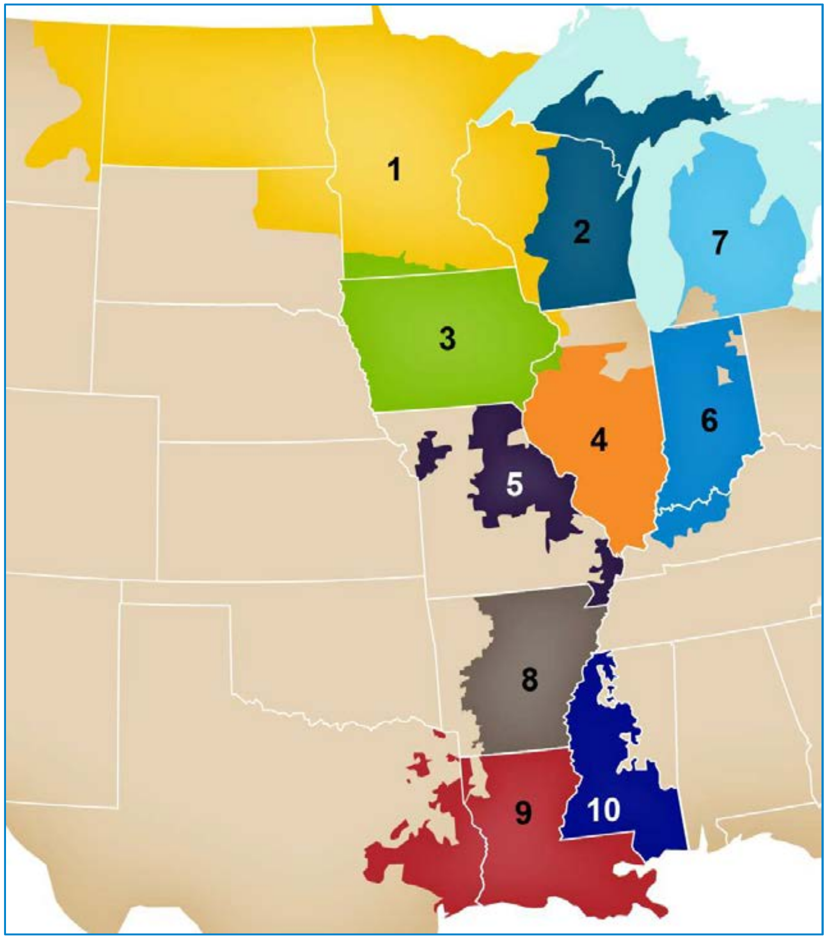
- **Load Modifying Resource (LMR) Testing Requirement Refinements (ER19-650)**

  In Feb. 2019, FERC approved part of MISO's Resource Availability and Need initiative related to Load Modifying Resource (LMR) availability. Further LMR Business Practice refinements clarified that LMRs must provide power test results or performance data from a previous event to avoid a potential underperformance penalty, or be subject to a penalty if it failed to perform during an emergency event.

- **Ongoing Fleet Change**
  - The auction results reflect the industry's ongoing shift away from coal-fired generation and an increasing reliance on gas-fired resources and non-traditional resources, such as intermittent renewable resources and various demand-based resources.
  - These trends are the basis for MISO's current Resource Availability and Need efforts, including an imminent filing to incentivize the improved availability of LMRs, which MISO is increasingly relying on to ensure reliable operations throughout the year.

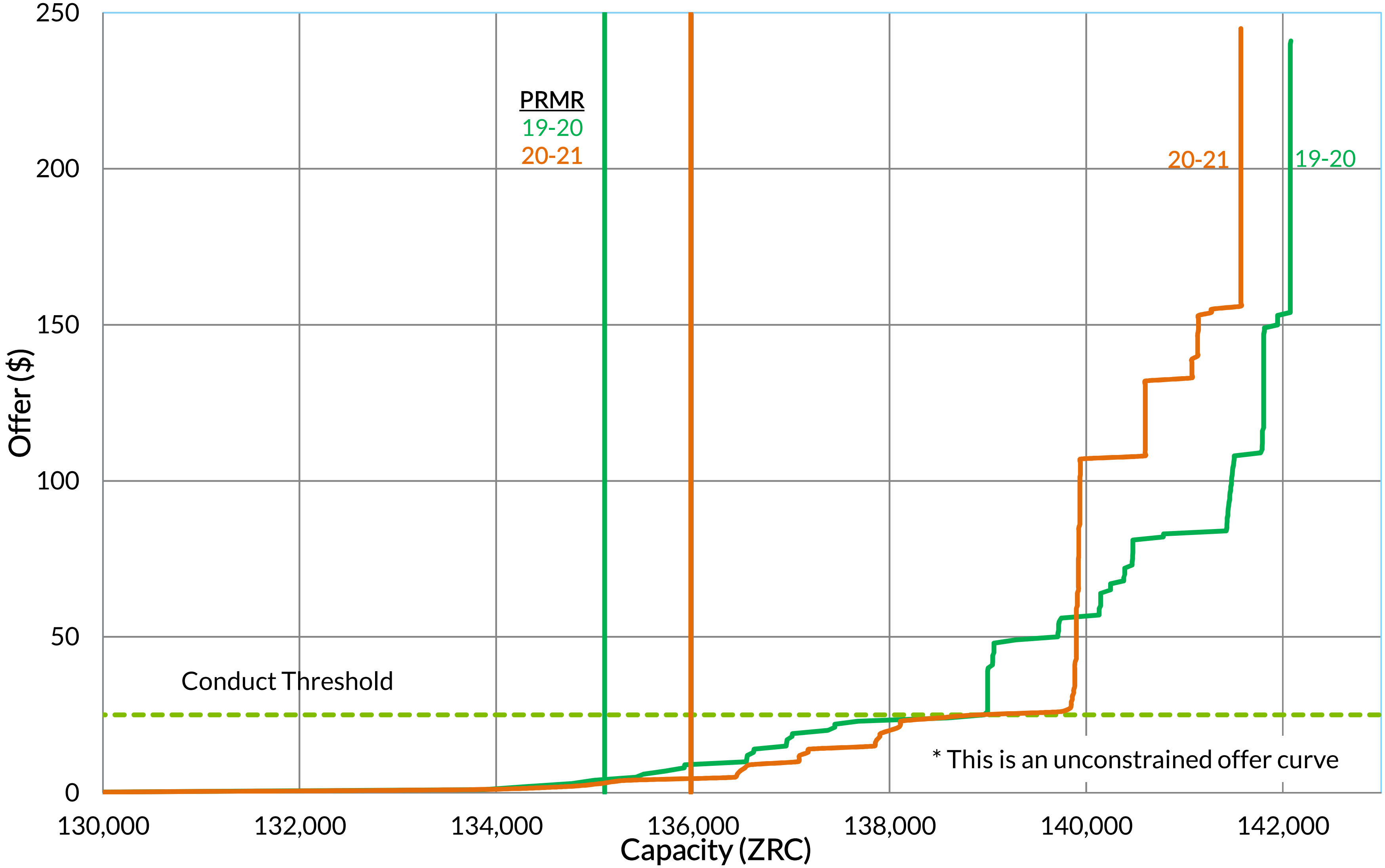
Auction Clearing Prices ~$5/MW-day with exception of Zone 7, which cleared at CONE

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$5.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$5.00
3	ALTW, MEC, MPW	$5.00
4	AMIL, CWLP, SIPC	$5.00
5	AMMO, CWLD	$5.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$5.00
7	CONS, DECO	$257.53
8	EAI	$4.75
9	CLEC, EES, LAFA, LAGN, LEPA	$6.88
10	EMBA, SME	$4.75
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$4.89-5.00



ERZ = External Resource Zones

2020-21 Offer Curve* generally similar to 2019-20



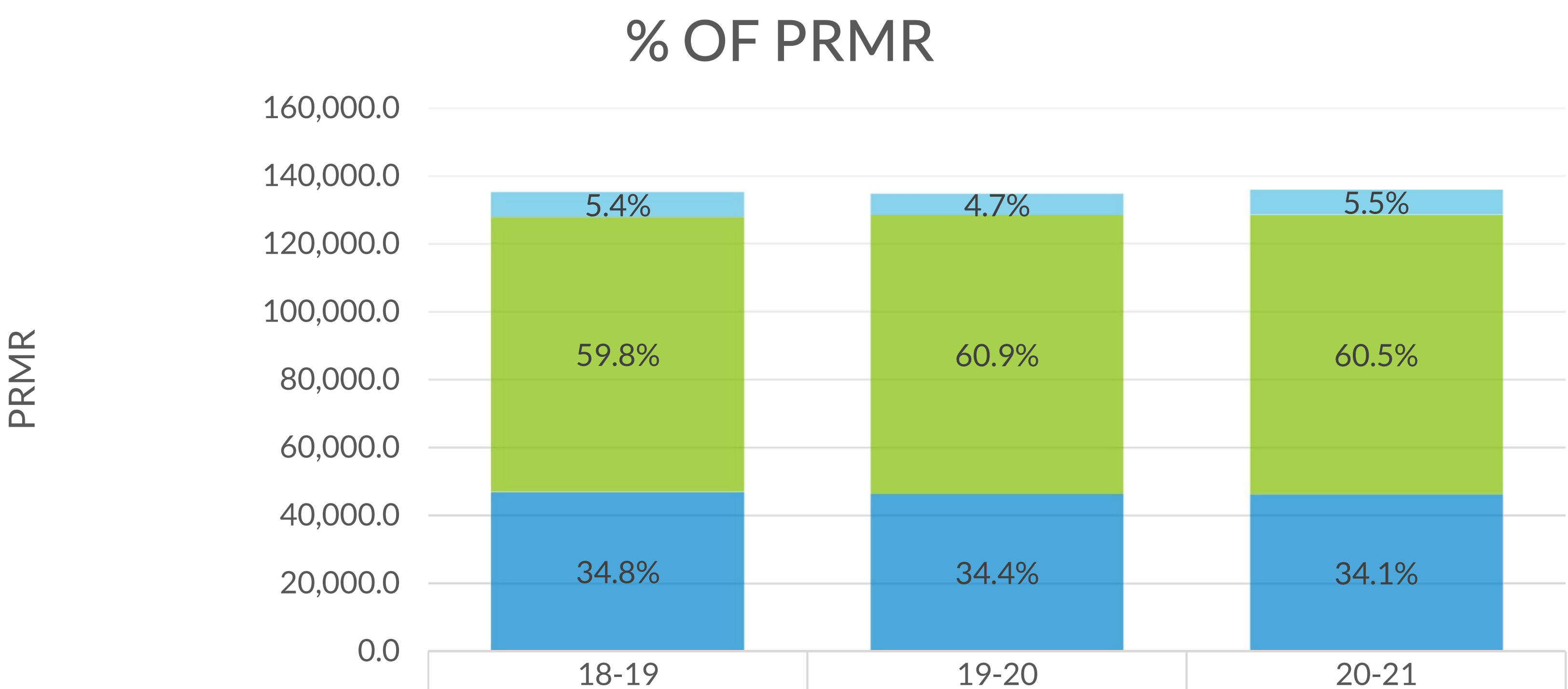
2020/21 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,476.0	13,728.2	10,129.1	9,794.6	8,456.3	18,720.6	21,945.3	7,986.9	21,711.7	5,030.6	N/A	135,979.3
Offer Submitted (Including FRAP)	20,296.4	14,056.1	10,822.0	10,281.4	7,952.8	17,134.6	21,727.5	10,573.5	21,800.7	5,300.2	1,629.0	141,574.2
FRAP	14,198.3	11,473.4	4,143.6	705.1	0.0	1,515.4	12,034.4	501.4	174.0	1,402.7	171.9	46,320.2
Self Scheduled (SS)	3,800.1	2,116.5	6,031.5	6,005.9	7,952.8	13,563.9	9,619.9	9,255.0	19,123.9	3,454.5	1,316.0	82,240.0
Non-SS Offer Cleared	743.6	0.1	375.9	1,751.1	0.0	1,975.3	73.2	426.7	1,595.8	387.0	90.4	7,419.1
Committed (Offer Cleared + FRAP)	18,742.0	13,590.0	10,551.0	8,462.1	7,952.8	17,054.6	21,727.5	10,183.1	20,893.7	5,244.2	1,578.3	135,979.3
LCR	17,058.9	13,331.9	7,671.9	6,744.2	4,453.3	12,778.3	21,850.7	6,243.1	20,893.7	3,688.3	-	N/A
CIL	2,902	1,603	3,284	6,003	5,424	7,326	3,200	3,824	3,410	3,160	-	N/A
ZIA	2,900	1,603	3,171	5,085	5,424	7,041	3,200	3,776	3,410	3,160	-	N/A
Import	0.0	138.2	0.0	1,332.5	503.5	1,666.0	217.8	0.0	818.0	0.0	-	4,676.0
CEL	4,101	-	-	3,859	-	4,622	-	-	1,918	1,658	-	N/A
Export	266.0	0.0	421.9	0.0	0.0	0.0	0.0	2,196.2	0.0	213.6	1,578.3	4,676.0
ACP ($/MW-Day)	5.00	5.00	5.00	5.00	5.00	5.00	257.53	4.75	6.88	4.75	4.90*	N/A

Values displayed in MW UCAP

04/14/2020: MISO Planning Resource Auction (PRA) for Planning Year 2020-2021 Results Posting

Members continue to utilize FRAP and Self Schedule to meet Resource Adequacy Requirements



	18-19	19-20	20-21
Cleared Non-Self Scheduled	7,252.6	6,281.9	7,419.1
Self Scheduled	80,896.1	82,046.9	82,240.0
FRAP	47,030.2	46,414.2	46,320.2

Historical Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2014-2015</td><td>$3.29</td><td colspan="6">$16.75</td><td colspan="2">$16.44</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
</table>

IMM Conduct Threshold	*25.61*	*25.17*	*25.02*	*25.46*	*26.08*	*25.49*	*25.75*	*24.56*	*23.66*	*24.50*	*26.08*
Cost of New Entry	*256.08*	*251.67*	*250.22*	*254.68*	*260.79*	*254.88*	*257.53*	*245.64*	*236.58*	*244.96*	*260.79*

- Auction Clearing Prices shown in $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)

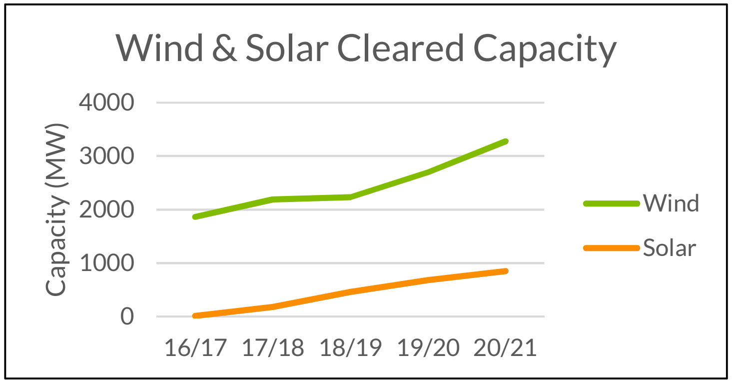
Supply Offered & Cleared

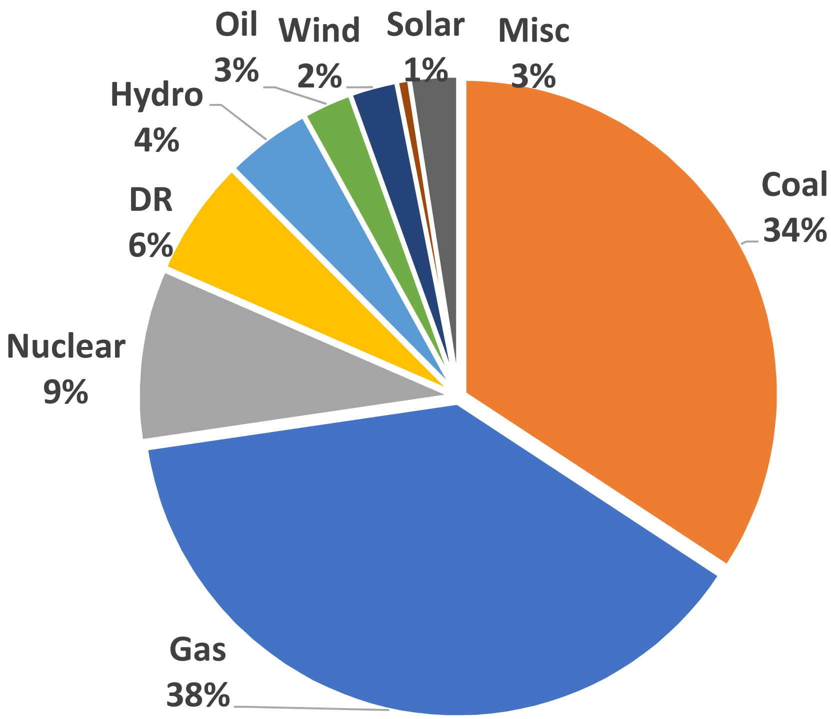
	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	2018-19	2019-20	2020-21	2018-19	2019-20	2020-21
Generation	126,159	125,290	125,341	120,855	119,779	120,143
External Resources	3,903	4,402	3,832	3,089	3,183	3,736
Behind the Meter Generation	4,176	4,202	3,997	4,098	4,097	3,892
Demand Resources	7,370	7,876	7,754	6,964	7,372	7,557
Energy Efficiency	173	312	650	173	312	650
Total	141,781	142,082	141,574	135,179	134,743	135,979

While conventional generation provides 80% of resources, wind and solar are growing…

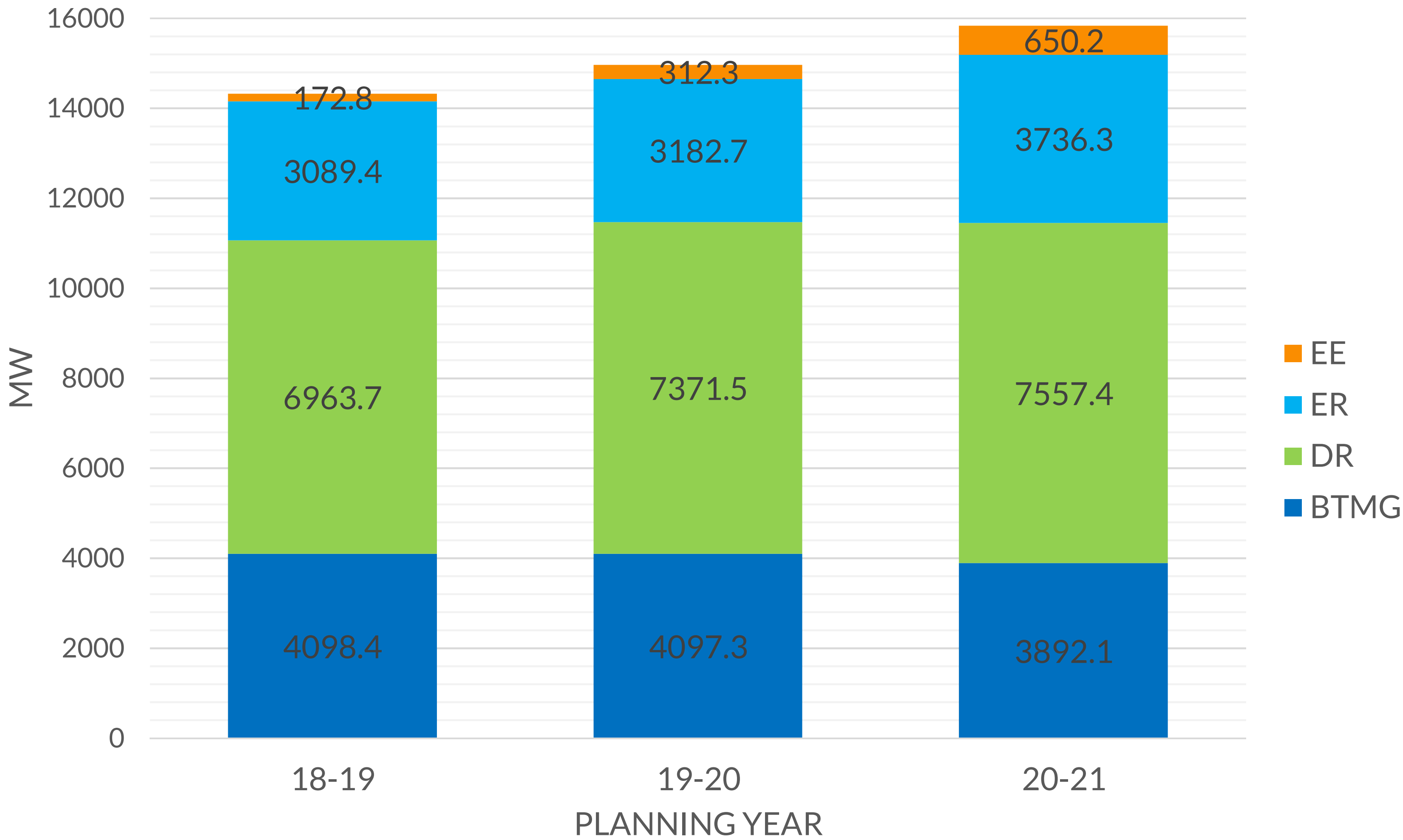
- 850MW of solar cleared this year's auction—an increase of 25% from PY 2019-20 (680 MW).

- Similarly, 3,275 MW of wind cleared this year, an increase of 21% compared to last year (2,697 MW).

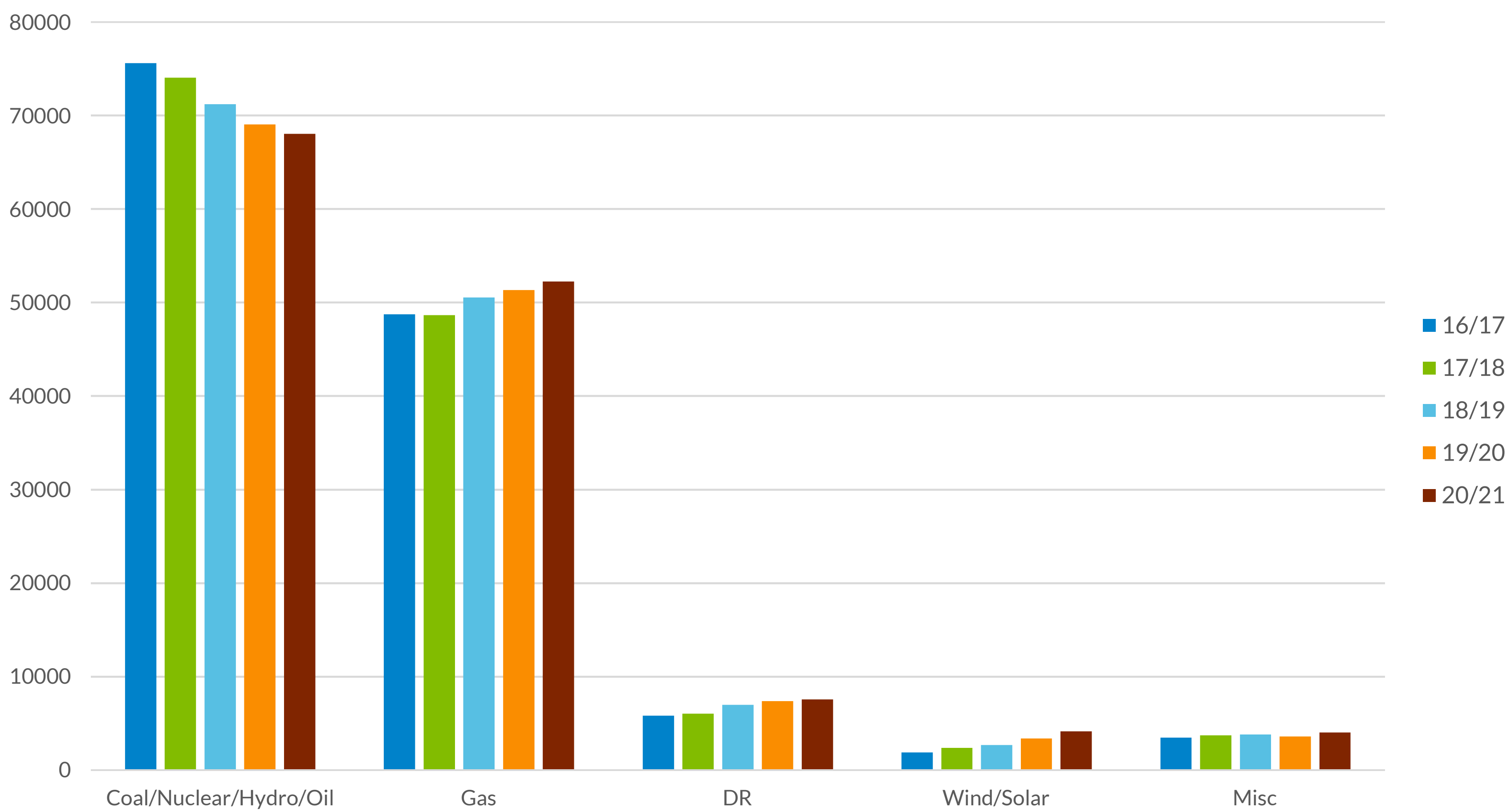




…as have demand-based resources…



…which continues trend of non-conventional resource gains over the past 5 years, and a primary driver for our pursuit of Resource Availability and Need initiatives



Next Steps

- APR 15 – Conference call presentation of PRA results
- MAY 6 – Detailed results review at RASC
- MAY 15 – Posting of PRA masked offer data
- MAY 25 – MISO published cleared LMRs to the MCS
- MAY 29 – LSE submit ICAP Deferral info
- JUN 1 – New Planning Year starts

Appendix

Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRZ: Local Resource Zone
LSE: Load Serving Entity
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SS: Self Schedule
SFT: Simultaneous Feasibility Test
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

MISO

RAdequacy@misoenergy.org

GRETCHEN WHITMER
GOVERNOR

STATE OF MICHIGAN
DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ORLENE HAWKS
DIRECTOR

TREMAINE L. PHILLIPS
COMMISSIONER

SALLY A. TALBERG
CHAIRMAN

DANIEL C. SCRIPPS
COMMISSIONER

November 7, 2019

Mr. John Bear
Chief Executive Officer
Midcontinent Independent System Operator
720 City Center Drive
P.O. Box 4202
Carmel, IN 46082-4202

Dear Mr. Bear,

The October 17, 2019 letter from Governor Gretchen Whitmer and the Michigan Public Service Commission (MPSC) referenced the MPSC's Statewide Energy Assessment recommendation to conduct additional analyses to increase the import capability for MISO's Local Resource Zone 7, covering the majority of Michigan's Lower Peninsula. Additional import capacity could help Michigan access diverse and economical supplies of power, assist with reliability and resiliency during emergency conditions, and meet MISO's annual resource adequacy requirements, particularly with respect to the zone's ability to meet the MISO local clearing requirement (LCR). As you know, Michigan is experiencing a significant number of power plant retirements and has the potential to be short of meeting the LCR in MISO's upcoming MISO Planning Resource Auction (PRA) based on MISO's loss of load expectation study.

Accordingly, the MPSC requests that MISO conduct a study to help the State of Michigan better understand the effects of increasing the Capacity Import Limits (CIL) and Capacity Export Limits (CEL) into and out of Local Resource Zone 7. This would augment MISO's research of Zone 7 in a current "Out-Year CIL-CEL Study Scope," which examines changes in import and export limits based on generation fleet changes but does not consider ways to expand the limits.

We consider MISO's regional planning and modeling expertise as necessary and invaluable to us as we look to determine whether and how Michigan is able to meet reliability goals going forward, including evaluating the potential costs and benefits of increased import and export limits in Zone 7.

Many fundamental characteristics of the Bulk Electric System have evolved over the last five years and change to the system is expected to accelerate. With projected capacity constraints in Zone 7, it is critical for Michigan to explore increasing its import and export limits. Specifically, we would like to better understand transmission solution options available to increase the limits into and out of Zone 7 in the near and long term.

Our first request is for MISO to analyze increasing the CIL and CEL in the near term at smaller increments such as 500 MW and 1,500 MW. The goal is to determine the infrastructure needed to accommodate cost-effective increases in the near term, with corresponding costs and benefits to Zone 7 and other Zones as applicable. Second, we seek to understand what types of projects could facilitate an increase in the CIL and CEL in Zone 7 by larger increments over the next decade to accommodate additional renewable energy and other changes in the generation mix. This may include additional high voltage infrastructure coming into Zone 7, as well as an estimate of corresponding costs and benefits. We would also like to understand how the costs of any projects proposed to increase the CIL and CEL would be allocated under the current MISO tariff, as well as explore other cost allocation methodologies that could be beneficial to furthering the development of transmission projects to increase the CIL and CEL for Zone 7.

We appreciate your consideration of this request and are open to addressing this request in a suitable MISO stakeholder forum, such as the MTEP, if the timing allows or addressing this request through a stand-alone process. Given the rapid changes occurring in the energy industry and the long lead time for infrastructure planning and development, we have a sense of urgency and look forward to collaborating with MISO on this request. In order to accomplish this request, the MPSC stands ready to address any open questions and technical support from our Staff. Thank you for your assistance.

Sincerely,

Sally Talberg Chairman	Dan Scripps Commissioner	Tremaine Phillips Commissioner

cc: Melissa Seymour
Carmen Clark

Michigan Capacity Import/Export Limit Expansion Study Update

A Michigan PSC requested, informational study to determ expansion options to increase the Capacity Import and Export Li for MISO Local Resource Zone

Michigan TSTF

May 19, 2020

Purpose and Key Takeaways

- Purpose
  - Inform Michigan PSC of initial results for Scenario 1 CIL.

Key Takeaways

- Thermal and two versions of voltage analysis were performed on the 5-year out model.
- Two potential transmission projects were identified under one of the versions of the voltage analysis.
- In each case, the resulting CIL was greater than the desired level of 4700MW.

Nov. 7, 2019 MPSC letter to MISO

- Requested a MISO study to help the State of Michigan better understand the effects of increasing the Capacity Import Limit (CIL) and Capacity Export Limit (CEL) into and out of Zone 7
- This study would augment MISO's Out-Year CIL-CEL Study Scope, which examines changes in import and export limits based on generation fleet changes but not look at how to expand the limits
- This study will help Michigan to meet it reliability goals and evaluate the potential costs and benefits of increased CILs & CELs

The Michigan Capacity Import/Export Limit Expansion Study is an informational-only study to determine expansion options to increase the capacity import and export limits for LRZ7

- MTEP Appendix A recommendations will not be made as a direct result of this study

Study Targeted CIL Expansions	
Local Smaller-Scope	Approximately 500 MW incremental increase in capacity import limit
Local Larger-Scope	Approximately 1,500 MW incremental increase in capacity import limit
Regional	3,000 MW+ incremental increase in capacity import limit

- Both Transmission and non-Transmission solutions will be evaluated.

Scenario-based approach to bookend out-year uncertainty used in an effort to increase certainty in results

Scenario 1
5 Year Outlook

- Model: LOLE20 Out-Year transfer analysis model - MTEP19 2024 Summer Peak case
- Updates: MTEP19 approved topology changes in Michigan and Surrounding Areas (e.g. Blue Water Reinforcement Project & related changes)
- Primary means to identify local scope options

Scenario 2
10+ Year Outlook

- Scenario 1 plus Integrated Resource Plan additions and retirements in the 10+ year timeframe (May 2032) to LRZ 7 made; no modifications to load or transmission
- First and second tier LRZ generation augmented based on the year 2032 expansion in the MTEP20 Accelerated Fleet Change Future
- Primary means to identify regional scope options

Scenario 3
High Renewables

- Scenario 2 plus 12,000 MW solar (total) & hybrid solar/storage (400 MW every 5 years)
- First and second tier LRZ generation augmented based on the year 2035 expansion in the MTEP20 Accelerated Fleet Change Future
- Primary means to identify regional scope options

At the conclusion of the study, MISO will provide a final report and summary presentation

- Deliverables will detail study results as well as study process and assumptions
- Study results will include transmission expansion options (facilities, scope, and voltages), estimated cost for each transmission expansion option, the associated increase in capacity import and export limits under each scenario, and qualitative benefits as applicable
- Local reliability requirements (LRR) for LRZ7 will be calculated using the generation fleet in Scenario 2 and Scenario 3
- MISO will not make any project recommendations to MTEP Appendix A based on the outcome from this study

Five-Year CIL Results:
Load-Load Voltage

Proposed Projects:
- Add 230 kV line from DIG 2 - River Rouge
- Install a 230/120 kV transformer connected to Equalizer bus (on low side)

CIL = 4,115 MW
- Limiting Element: Praxair 120 kV

CIL = 4,300 MW
- Limiting Element: Diesel 120 kV

CIL = 4,715 MW
- Limiting Element: Diesel 120 kV

Proposed Projects:
- Interchange the Lallendorf - Monroe and Lemoyne - Majestic 345 kV lines
- Build a new Wayne-Monroe parallel 345 kV circuit

Five-Year CIL Results: Thermal

Assumptions

- Added probable/future generation to the base model in the transfer source areas to counter retirements taken in those same areas

CIL = 5100 MW

- No valid constraints identified in base case; Generation Limited Dispatch (GLT) performed
- Constraint identified at 20% GLT
- Limiting Element: Monroe – Brownstone 345 kV

Five-Year CIL Results:
Gen-Gen Voltage

Modification:

- Ignore generator Pmax in study transfer source

Initial Run

- Transfer source ran out of generation before transfer completed
- No viable results

Final Run

- Successful transfer completed
- No constraint identified

Five-Year CIL Results: Summary

Load-Load Voltage Analysis

- CIL = 4715 MW
- Limiting Element = Diesel 120 kV (4 projects implemented)
- Contingency = P12

Thermal Analysis

- CIL = 5100 MW
- Limiting Element = Monroe – Brownstone 345 kV
- Contingency = P12

Gen-Gen Voltage Analysis

- No constraint identified – default to Thermal CIL of 5100 MW

Study will be conducted through an open and transparent study process - MISO stakeholders are encouraged to identify and submit potential solutions to the study

Date	Venue	Purpose
February 6, 2020	MI PSC	Kick Off & Assumptions
February 12, 2020	MISO PAC	Kick Off & Assumptions
May 19, 2020	MI TSTF	Initial results update
July 20, 2020	TSTF	Preliminary Results & Solution Submission
September 2020	TSTF	Robustness Results & Refinement
November 2020	MI PSC	Review results with Commission
November 11, 2020	PAC	Final results

Subject to change based on study scope and needs. Regional options may require additional time to study for coordination with current MTEP20 studies.

All meeting notifications and postings will be via the MISO public website

MISO PAC: MISO Planning Advisory Committee

MI TSTF: Existing Michigan Technical Study Task Force Meetings

TSTF: Technical Study Task Force meetings specifically for this study

Next Steps

- Scenario 2 model build is underway
- Continue working with Stakeholders and issues are identified through scenarios 2 and 3.
- Results shared in July 20th meeting
    - Stakeholders will be able to provide alternative solutions.

For Additional Questions:

Tony Rowan: arowan@misoenergy.org
Thompson Adu: tadu@misoenergy.org

MISO

2020/2021 Planning Resource Auction (PRA) Results

May 6, 2020

Resource Adequacy Sub-Committee (RASC)

Purpose & Key Takeaways

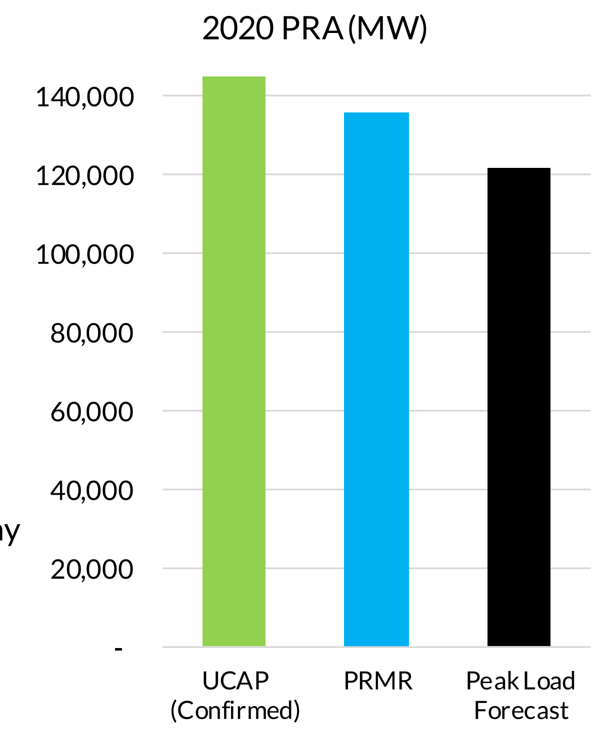
Purpose: Additional insight into the PRA results, with additional information on the Zonal Deliverability Benefits, and comparison to 2019 LOLE study.

Key Takeaways:

- Most zones cleared $4.75-$6.88/MW-day, with Zone 7 clearing at CONE
- Zonal Deliverability Benefit (ZDB) distribution ranges from $0.01 to $2.51 / MW-day for importing benefitting zones
- 2019 LOLE study results consistent with 2020 PRA, and MISO to conduct a sensitivity analysis on Zone 7

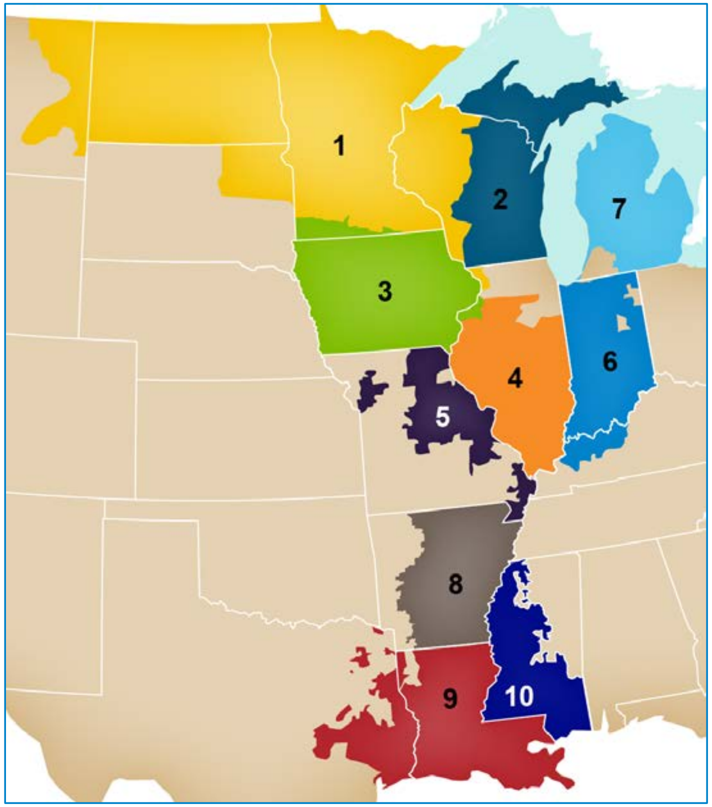
MISO region has adequate reserves to meet its 136 GW Planning Reserve Requirement

- Most zones cleared **$4.75-$6.88**/MW-day
- Zone 7 (MI) cleared at Cost of New Entry (CONE) **$257.53**/MW-day
  - Insufficient local capacity to meet Local Clearing Requirement (LCR)
- South to North capacity reached limit causing price separation of $0.25
- Zonal Deliverability Benefit (ZDB) distribution:
  - Zones 1-6: **$0.01**, Zone 7: **$2.51**, Zone 9: **$0.07** / MW-day
- Regional generation supply consistent with the 2019 OMS-MISO Survey
- Independent Market Monitor has reviewed and validated results. No instances of physical or economic withholding.



Auction Clearing Prices ~$5/MW-day with exception of Zone 7, which cleared at CONE

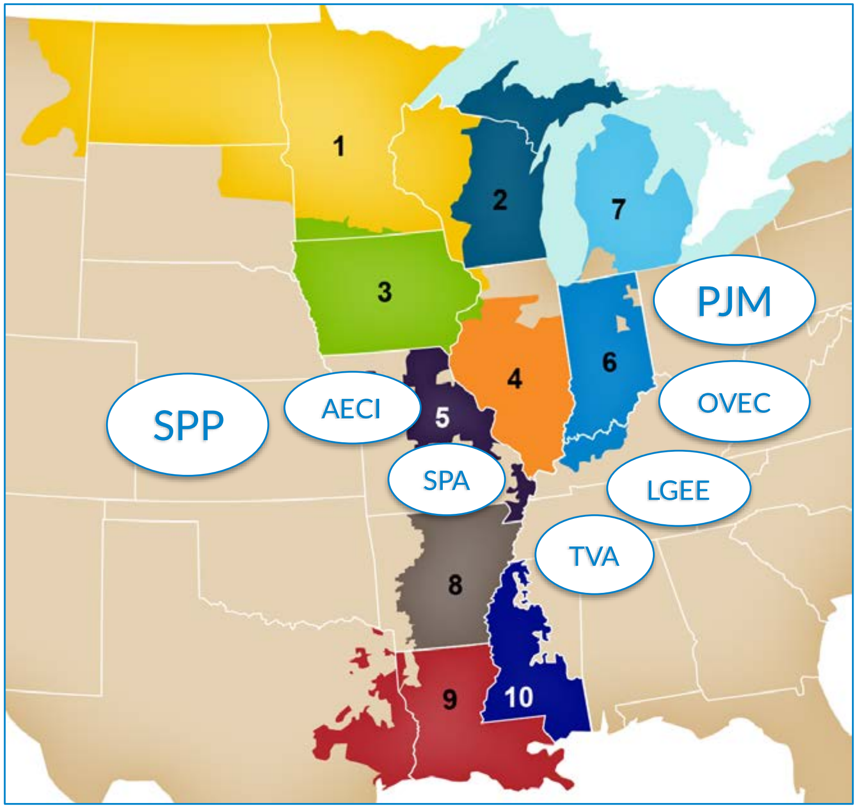
Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$5.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$5.00
3	ALTW, MEC, MPW	$5.00
4	AMIL, CWLP, SIPC, GLH	$5.00
5	AMMO, CWLD	$5.00
6	BREC, CIN, HE, IPL, NIPS, SIGE, HMPL	$5.00
7	CONS, DECO	$257.53
8	EAI	$4.75
9	CLEC, EES, LAFA, LAGN, LEPA	$6.88
10	EMBA, SME	$4.75
ERZ	SPP, PJM, OVEC, LGEE, AECI, SPA, TVA	$4.89-5.00



ERZ = External Resource Zones

MISO imported 1500MW from External zones which cleared at sub-regional or blended pricing

External Resource Zone	Export (MW)	Price ($/MW-Day)
SPP	347	$4.90
PJM	633	$5.00
OVEC	30	$5.00
LGEE	148	$5.00
AECI	24	$4.92
SPA	199	$4.89
TVA	227	$4.90
Total	**1578**	



Zonal Deliverability Benefit amount to $56,950/day surplus due to price separation and capacity importing from lower priced zones

Zones	PRMR (MW)	Cleared Resources (MW)	ACP ($/MW-day)	DEBIT (ACP * PRMR)	CREDIT (ACP * Cleared Resources)
1	18,476.0	18,742.0	5.00	$ 92,380.00	$ 93,710.00
2	13,728.2	13,590.0	5.00	$ 68,641.00	$ 67,950.00
3	10,129.1	10,551.0	5.00	$ 50,645.50	$ 52,755.00
4	9,794.6	8,462.1	5.00	$ 48,973.00	$ 42,310.50
5	8,456.3	7,952.8	5.00	$ 42,281.50	$ 39,764.00
6	18,720.6	17,054.6	5.00	$ 93,603.00	$ 85,273.00
7	21,945.3	21,727.5	257.53	$ 5,651,573.11	$ 5,595,483.08
8	7,986.9	10,183.1	4.75	$ 37,937.78	$ 48,369.73
9	21,711.7	20,893.7	6.88	$ 149,376.50	$ 143,748.66
10	5,030.6	5,244.2	4.75	$ 23,895.35	$ 24,909.95
PJM	0.0	633.8	5.00	$ -	$ 3,169.00
OVEC	0.0	30.1	5.00	$ -	$ 150.50
LGEE	0.0	148.4	5.00	$ -	$ 742.00
SPP	0.0	347.2	4.90	$ -	$ 1,701.28
TVA	0.0	226.5	4.90	$ -	$ 1,109.85
AECI	0.0	24.0	4.92	$ -	$ 118.08
SPA	0.0	168.3	4.89	$ -	$ 822.99
Totals	135,979.3	135,979.3		$ 6,259,306.73	$ 6,202,087.60
				Surplus Sub Total	$ 57,219.13
				FRAP/HUC	$ (268.51)
				Total Surplus	**$ 56,950.62**

Surplus revenue will be distributed to HUCs and pro rata to LSEs in the importing Deliverability Benefitting Zones (DBZ):

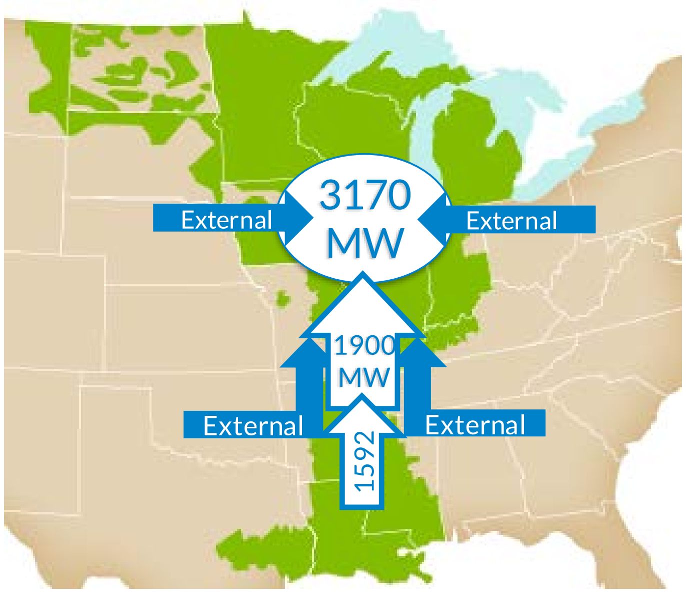
DBZ	ZDB $/MW-day
1-6	$0.01
7	$2.51
9	$0.07

MISO North zones imported over 3000MW while the South to North limit was reached causing a modest $0.25 clearing price separation

MISO North imported 3170 MW, comprised of:

- 1270 MW External Resources
- 1900 MW from MISO South
  - 1592 MW Internal Resources
  - 308 MW External Resources

The South-to-North limit was determined through the annual Sub-Regional Import/Export Limit analysis to be 1900 MW in advance of this year's PRA. This South- to-North limit previously bound in the 2016 auction.



340MW of capacity met Long Term Outage criteria, therefore unable to be used towards Resource Adequacy requirements in this year's PRA

In January 2020, FERC approved MISO's filing ER20-129 where resources with planned outages or derates that were reasonably expected to last more than 90 of the first 120 days in a Planning Year would be ineligible for participation in that associated PRA.

Breakdown by Zone:

Zone	MW
1	1.3
3	1
7	337.3
Total	**339.6**

Capacity used in the 2019 LOLE Study was slightly higher as compared to 2020 PRA

Slight variation in capacity driven by:

- Approved Attachment Y retirements after LOLE cut-off date (June 1 2019)
- Generator Variables (GVTC, XEFORd etc.)
  - LOLE used 2018 GVTC PRA used 2019 GVTC
  - LOLE used 5 year XEFORd (2014-2018) PRA used 3 year XEFORd (2016-2019)

	2020/21 LOLE UCAP	2020/21 PRA UCAP	Delta UCAP	Delta (%)
Generation	129,015	125,341	(3,674)	-3%
Behind the Meter Generation	4,416	3,997	(419)	-10%
Demand Response	7,836	7,754	(82)	-1%
External Resources	4,450	3,832	(618)	-16%
Energy Efficiency	312	650	338	52%
Total	146,029	141,574	(4,455)	-3%

LOLE peak demand forecasts consistent with PRA

MISO coincident peak demand from LOLE study used to set the 2020/21 PY PRM.

MISO Coincident Peak				
Zone	2020/21 PY LOLE (MW)	2020/21 PY PRA (MW)	Delta (MW)	Delta (%)
MISO	124,659	124,865	206	0%

LRZ zonal coincident peak demands from LOLE study used to set the 2020/21 PY Local Reserve Requirement.

Zonal Coincident Peak				
Zone	2020/21 PY LOLE (MW)	2020/21 PY PRA (MW)	Delta (MW)	Delta (%)
LRZ-1	17,815	17,483	(332)	-2%
LRZ-2	12,728	12,787	59	0%
LRZ-3	9,558	9,496	(62)	-1%
LRZ-4	9,185	9,174	(11)	0%
LRZ-5	7,830	7,966	136	2%
LRZ-6	17,585	17,471	(114)	-1%
LRZ-7	21,226	20,963	(263)	-1%
LRZ-8	7,685	7,584	(101)	-1%
LRZ-9	20,885	20,880	(6)	0%
LRZ-10	4,673	4,694	21	0%

To better understand the impact of insufficient local capacity to meet Zone 7's Local Clearing Requirement, MISO to conduct a sensitivity loss of load probability analysis on Zone 7

Sensitivity analysis scope:

Conduct Loss of Load Expectation sensitivity comparing two (2) scenarios:

- Zone 7 2019 PRA Results with application of Long Term Outage policy to planning resources
- Zone 7 2020 PRA Results

MISO to present the results at the June RASC meeting

Next Steps

- MAY 15 – Posting of PRA masked offer data
- MAY 25 – MISO published cleared LMRs to the MCS
- MAY 29 – LSE submit ICAP Deferral info
- JUN 1 – New Planning Year starts

Appendix

MISO's RA construct combines regional and local criteria to achieve a least-cost solution for the region

Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:

- Submit a Fixed Resource Adequacy Plan (FRAP)
- Utilize bilateral contracts with another resource owner
- Participate in the Planning Resource Auction (PRA)

The Independent Market Monitor (IMM) reviews the auction results for physical and economic withholding

Inputs

- Local Clearing Requirement (LCR) = capacity required from within each zone
- MISO-wide reserve margin requirements, which can be shared among the Zones, and Zones may import capacity to meet this requirement above LCR
- Capacity Import/Export Limits (CIL/CEL) = Zonal transmission limitations
- Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

Outputs

- Commitment of capacity to the MISO region, including performance obligations
- Capacity price (ACP = Auction Clearing Price) for each Zone
- ACP price drives the settlements process
- Load pays the Auction Clearing Price for the Zone in which it is physically located
- Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located

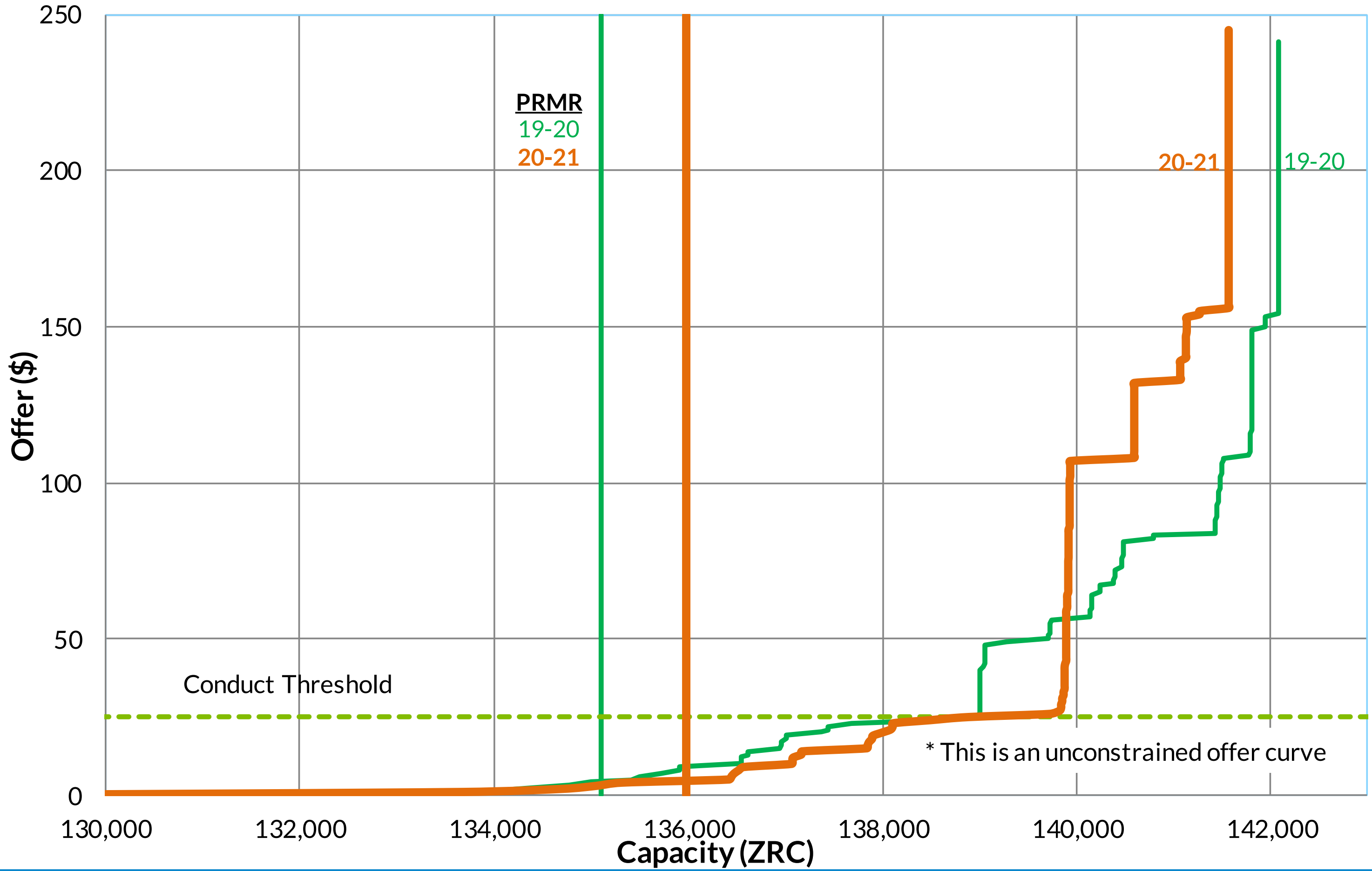
Three primary changes since 2019 Auction

- **Preclude Resources on Long Term Outages from Participation in the PRA (ER20-129)**
  In January 2020, FERC approved MISO's filing to limit the ability of Resources to participate in a Fixed Resource Adequacy Plan ("FRAP") and MISO's Planning Resource Auction ("PRA"), if the Resource has expected full or partial outages that last for any ninety (90) or more of the first 120 Calendar Days of the Planning Year which is consistent with the highest period of LOLE risk.

- **Load Modifying Resource (LMR) Testing Requirement Refinements (ER19-650)**
  In Feb. 2019, FERC approved part of MISO's Resource Availability and Need initiative related to Load Modifying Resource (LMR) availability. Further LMR Business Practice refinements clarified LMRs must now provide actual real power test results or performance data from a previous event during the LMR registration process to avoid a potential underperformance penalty. An LMR could opt-out of providing test or performance, but would be subject to a penalty if it failed to perform during an emergency event.

- **Ongoing Fleet Change**
  - The auction results reflect the industry's ongoing shift away from coal-fired generation and an increasing reliance on gas-fired resources and non-traditional resources, such as intermittent renewable resources and various demand-based resources. These trends are the basis for MISO's current Resource Availability and Need efforts.

2020-21 Offer Curve* generally similar to 2019-20



2020/21 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,476.0	13,728.2	10,129.1	9,794.6	8,456.3	18,720.6	21,945.3	7,986.9	21,711.7	5,030.6	N/A	135,979.3
Offer Submitted (Including FRAP)	20,296.4	14,056.1	10,822.0	10,281.4	7,952.8	17,134.6	21,727.5	10,573.5	21,800.7	5,300.2	1,629.0	141,574.2
FRAP	14,198.3	11,473.4	4,143.6	705.1	0.0	1,515.4	12,034.4	501.4	174.0	1,402.7	171.9	46,320.2
Self Scheduled (SS)	3,800.1	2,116.5	6,031.5	6,005.9	7,952.8	13,563.9	9,619.9	9,255.0	19,123.9	3,454.5	1,316.0	82,240.0
Non-SS Offer Cleared	743.6	0.1	375.9	1,751.1	0.0	1,975.3	73.2	426.7	1,595.8	387.0	90.4	7,419.1
Committed (Offer Cleared + FRAP)	18,742.0	13,590.0	10,551.0	8,462.1	7,952.8	17,054.6	21,727.5	10,183.1	20,893.7	5,244.2	1,578.3	135,979.3
LCR	17,058.9	13,331.9	7,671.9	6,744.2	4,453.3	12,778.3	21,850.7	6,243.1	20,893.7	3,688.3	-	N/A
CIL	2,902	1,603	3,284	6,003	5,424	7,326	3,200	3,824	3,410	3,160	-	N/A
ZIA	2,900	1,603	3,171	5,085	5,424	7,041	3,200	3,776	3,410	3,160	-	N/A
Import	0.0	138.2	0.0	1,332.5	503.5	1,666.0	217.8	0.0	818.0	0.0	-	4,676.0
CEL	4,101	-	-	3,859	-	4,622	-	-	1,918	1,658	-	N/A
Export	266.0	0.0	421.9	0.0	0.0	0.0	0.0	2,196.2	0.0	213.6	1,578.3	4,676.0
ACP ($/MW-Day)	5.00	5.00	5.00	5.00	5.00	5.00	257.53	4.75	6.88	4.75	4.90*	N/A

Values displayed in MW UCAP, * = average ACP

With few exceptions, historical auction clearing prices continue to remain low, reflective of MISO regional makeup

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2014-2015</td><td>$3.29</td><td colspan="6">$16.75</td><td colspan="2">$16.44</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
</table>

IMM Conduct Threshold	*25.61*	*25.17*	*25.02*	*25.46*	*26.08*	*25.49*	*25.75*	*24.56*	*23.66*	*24.50*	*26.08*
Cost of New Entry	*256.08*	*251.67*	*250.22*	*254.68*	*260.79*	*254.88*	*257.53*	*245.64*	*236.58*	*244.96*	*260.79*

- Auction Clearing Prices shown in $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)

A three year comparison demonstrates fairly consistent amount supply offered & cleared in aggregate, while demand side resources continue to rise

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**2018-19**	**2019-20**	**2020-21**	**2018-19**	**2019-20**	**2020-21**
Generation	126,159	125,290	125,341	120,855	119,779	120,143
External Resources	3,903	4,402	3,832	3,089	3,183	3,736
Behind the Meter Generation	4,176	4,202	3,997	4,098	4,097	3,892
Demand Resources	7,370	7,876	7,754	6,964	7,372	7,557
Energy Efficiency	173	312	650	173	312	650
Total	**141,781**	**142,082**	**141,574**	**135,179**	**134,743**	**135,979**

Variations in Resource Adequacy requirements are largely attributed to changing resource mix, performance and load shapes even though peak load forecasts remain steady

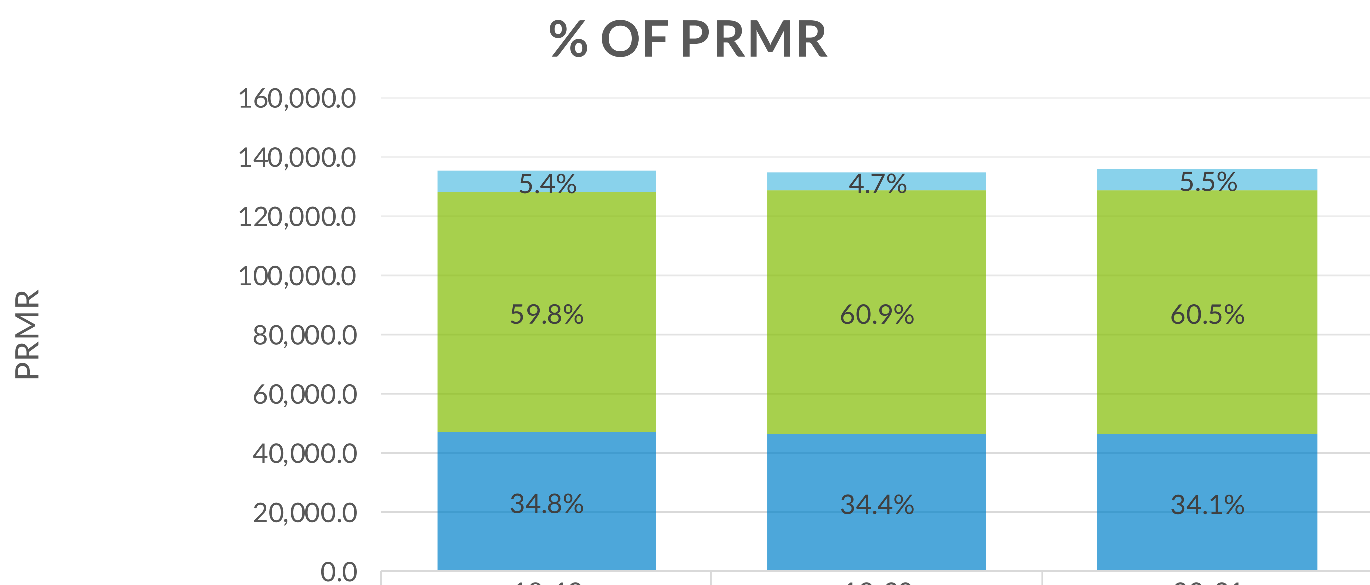
Local Resource Zone	Local Clearing Requirement (LCR) in MW		Planning Reserve Margin Requirement (PRMR) in MW		Coincident Peak Demand Forecast (CPDF) in MW	
	2019-20	2020-21	2019-20	2020-21	2019-20	2020-21
1	16,589	17,059	18,375	18,476	16,541	16,403
2	13,018	13,332	13,450	13,728	12,258	12,353
3	7,960	7,672	9,882	10,129	8,966	8,997
4	6,222	6,744	9,792	9,795	8,923	8,820
5	4,860	4,453	8,297	8,456	7,551	7,630
6	13,226	12,778	18,660	18,721	16,820	16,720
7	21,812	21,851	21,976	21,945	19,759	19,575
8	6,116	6,243	7,964	7,987	7,194	7,169
9	19,525	20,894	21,350	21,712	19,330	19,508
10	3,049	3,688	4,997	5,031	4,505	4,504

https://cdn.misoenergy.org/20191106%20RASC%20Item%2003a%20PY%202020-21%20LOLE%20study%20results397078.pdf

Year over year comparison reflects the industry's ongoing shift away from coal-fired generation and an increasing reliance on gas-fired resources and non-traditional resources

Planning Year	2019-20		2020-21		Change	
GADS Fuel Type	System (MW)	% Fuel	System (MW)	% Fuel	Delta (MW)	Delta (%)
Coal	47,059	34.93%	46,576	34.25%	-483	-1.03%
Gas	51,317	38.08%	52,247	38.42%	930	1.81%
Nuclear	12,274	9.11%	12,034	8.85%	-240	-1.96%
Load Modifier (DR/EE)	7,722	5.73%	8,208	6.04%	486	6.29%
Water	6,176	4.58%	6,021	4.43%	-155	-2.51%
Oil	3,528	2.62%	3,411	2.51%	-117	-3.32%
Wind	2,698	2.00%	3,275	2.41%	577	21.39%
Waste Heat	1,125	0.83%	1,204	0.89%	79	7.03%
Other-Solid(Tons)	814	0.60%	838	0.62%	24	2.89%
Distillate Oil	604	0.45%	582	0.43%	-22	-3.58%
Other-Liquid(BBL)	49	0.04%	48	0.04%	-1	-1.43%
Other-Gas(Cu Ft)	553	0.41%	542	0.40%	-11	-2.06%
Wood	144	0.11%	143	0.11%	-1	-0.76%
Solar	680	0.50%	850	0.63%	170	25.06%
SYSTEM	**134,743**	**100%**	**135,978**	**100%**	**1,235**	**0.92%**

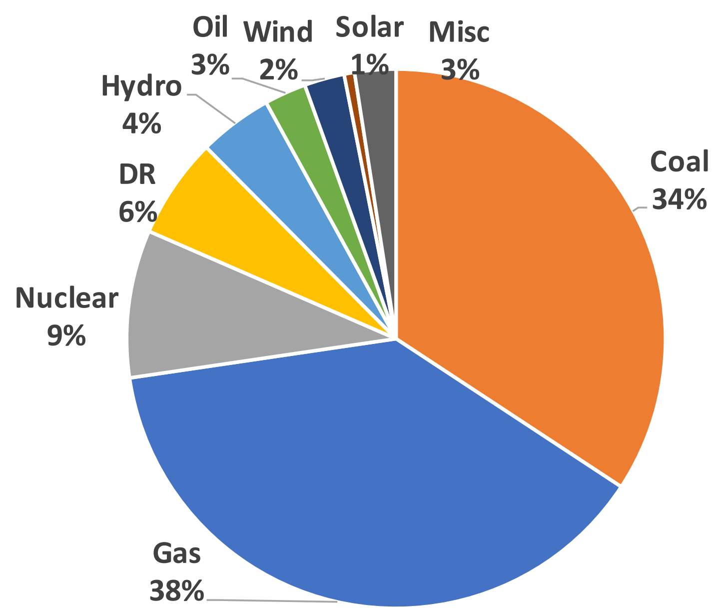
Members continue to utilize FRAP and Self Schedule to meet Resource Adequacy Requirements

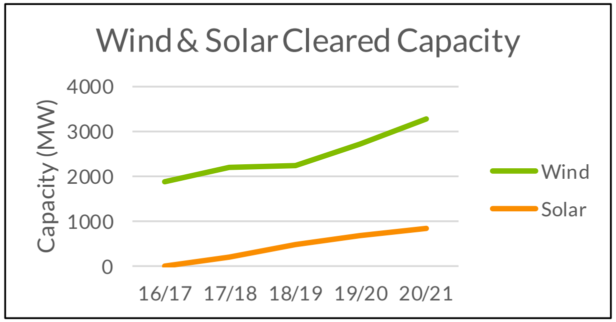


	18-19	19-20	20-21
Cleared Non-Self Scheduled	7,252.6	6,281.9	7,419.1
Self Scheduled	80,896.1	82,046.9	82,240.0
FRAP	47,030.2	46,414.2	46,320.2

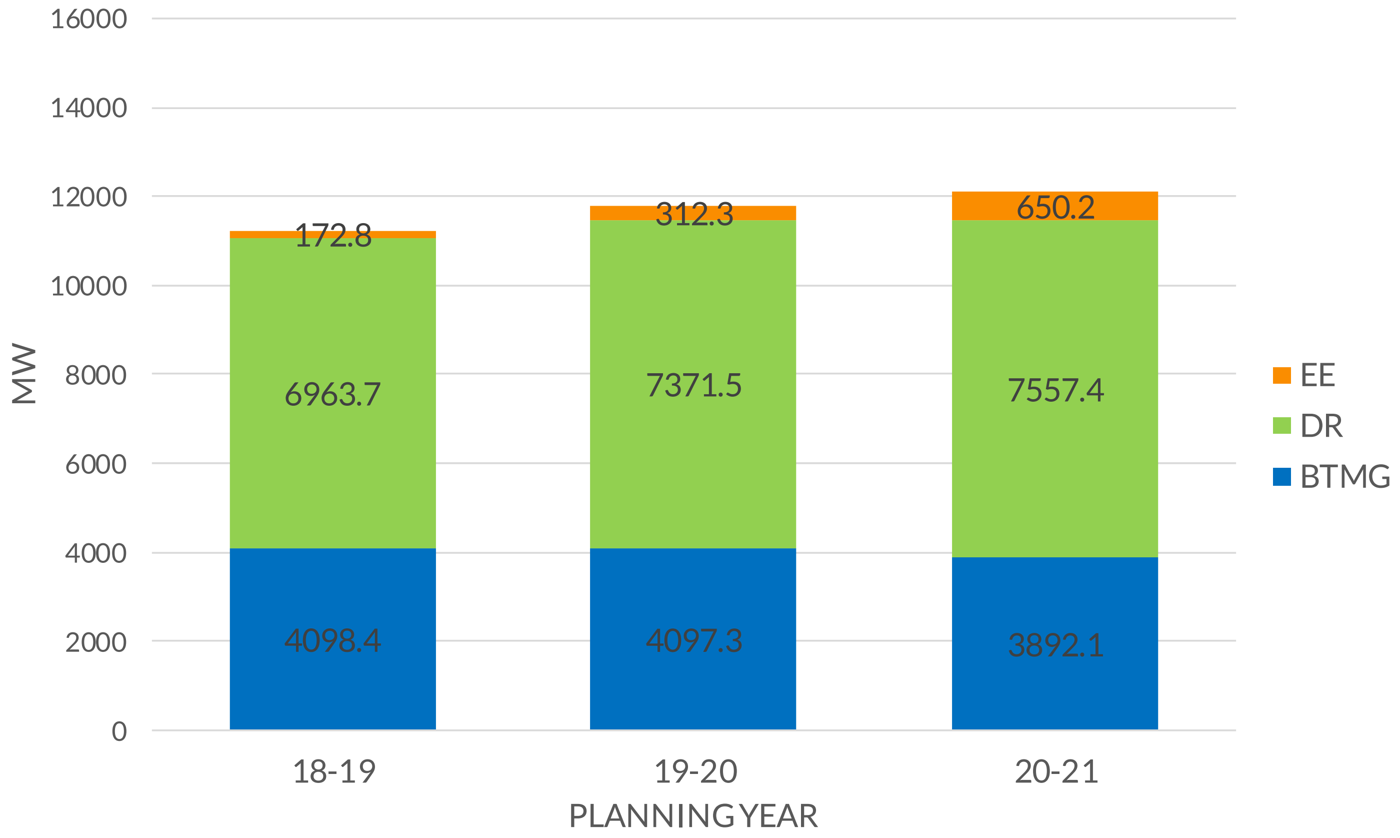
While conventional generation provides 80% of resources, wind and solar are growing…

- 850MW of solar cleared this year's auction—an increase of 25% from PY 2019-20 (680 MW).
- Similarly, 3,275 MW of wind cleared this year, an increase of 21% compared to last year (2,697 MW).

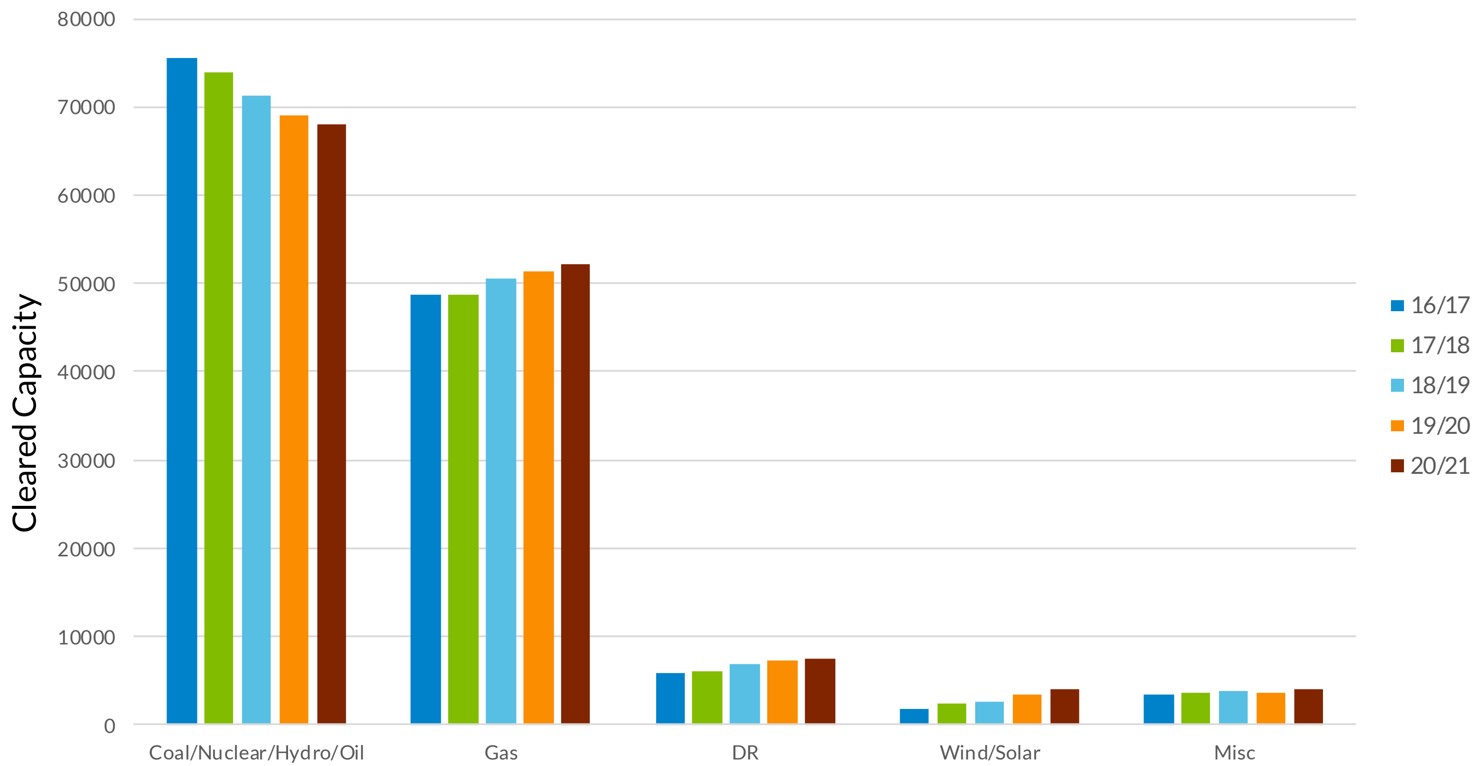




…as have demand-based resources…



…which continues the trend of non-conventional resource gains over at least the past 5 years



UCAP Confirmation and Conversion

LRZ	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZ	Total	Formulas
UCAP Total	20,919	14,081	11,816	11,779	7,957	17,457	21,826	10,843	22,736	5,322	1,693	146,428	A
UCAP (Confirmed)	20,835	14,081	11,462	11,356	7,957	17,457	21,781	10,843	21,926	5,322	1,693	144,712	B
UCAP (Unconfirmed)	85	-	354	423	-	-	45	-	810	-	-	1,716	C=A-B
Converted UCAP (ZRC)	20,507	14,074	10,843	10,762	7,957	17,411	21,604	10,726	21,822	5,322	1,686	142,713	D
Unconverted UCAP	328	7	619	594	-	46	177	117	104	-	7	1,999	E=B-D
FRAP + ZRC Offer	20,251	14,056	10,796	10,248	7,953	17,135	21,559	10,574	21,798	5,294	1,629	141,290	F
ZRC Not Offered/FRAP	257	18	47	514	4	276	45	153	24	28	57	1,423	G=D-F
MW/ZRC not participating in MISO PRA	669	25	1,020	1,531	4	322	267	269	938	28	64	5,137	H=C+E+G

- Common reasons why ZRCs may not participate in a PRA:
  - Capacity sales to other markets
  - Suspensions not participating in PRA
  - Exclusion granted by the IMM
  - General withholding from the PRA within the Physical Withholding Threshold

Supplemental Data for PRMR and LCR Calculations

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	SYSTEM
CPDF (Coincident Peak Demand Forecast)	16,403	12,353	8,997	8,820	7,630	16,720	19,575	7,169	19,508	4,504	121,680
CPDF + Transmission Losses	16,966	12,606	9,301	8,994	7,765	17,190	20,152	7,334	19,937	4,620	124,865
Planning Reserve Margin (PRM)	8.90%										
PRMR (Planning Reserve Margin Requirement)	18,476	13,728	10,129	9,795	8,456	18,721	21,945	7,987	21,712	5,031	135,979
ZCPDF (Zonal Coincident Peak Demand Forecast)	17,059	12,539	9,304	8,978	7,813	16,956	20,237	7,436	20,454	4,591	125,367
ZCPDF + Zonal Trans. Losses	17,483	12,787	9,496	9,174	7,966	17,471	20,963	7,584	20,880	4,694	128,498
LRR (Local Reliability Requirement) Factor	1.142	1.168	1.15	1.292	1.24	1.149	1.195	1.33	1.164	1.459	N/A
LRR	19,966	14,935	10,921	11,853	9,877	20,074	25,051	10,087	24,304	6,848	N/A
ZIA (Zonal Import Ability)	2,900	1,603	3,171	5,085	5,424	7,041	3,200	3,776	3,410	3,160	N/A
Non-Pseudo Tied Exports	7	0	78	24	0	255	0	68	0	0	432
LCR (Local Clearing Requirement)	17,059	13,332	7,672	6,744	4,453	12,778	21,851	6,243	20,894	3,688	N/A
LCR as a % of PRMR	92%	97%	76%	69%	53%	68%	100%	78%	96%	73%	N/A

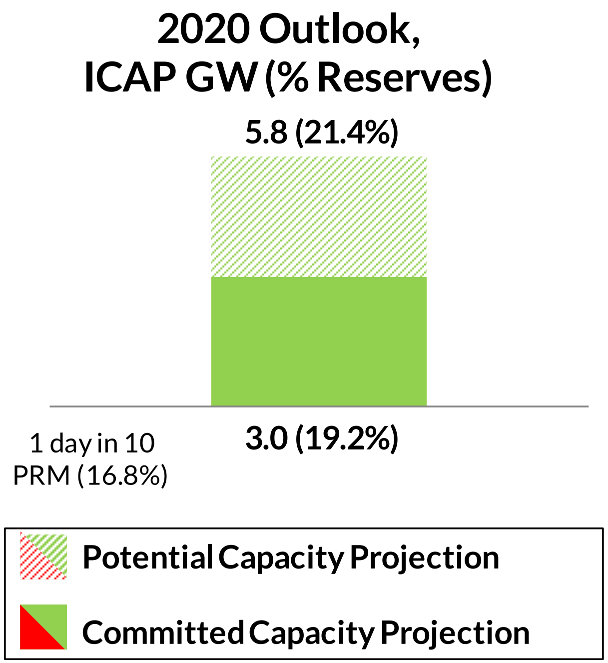
Forecasted requirements from LOLEWG were consistent with PRA

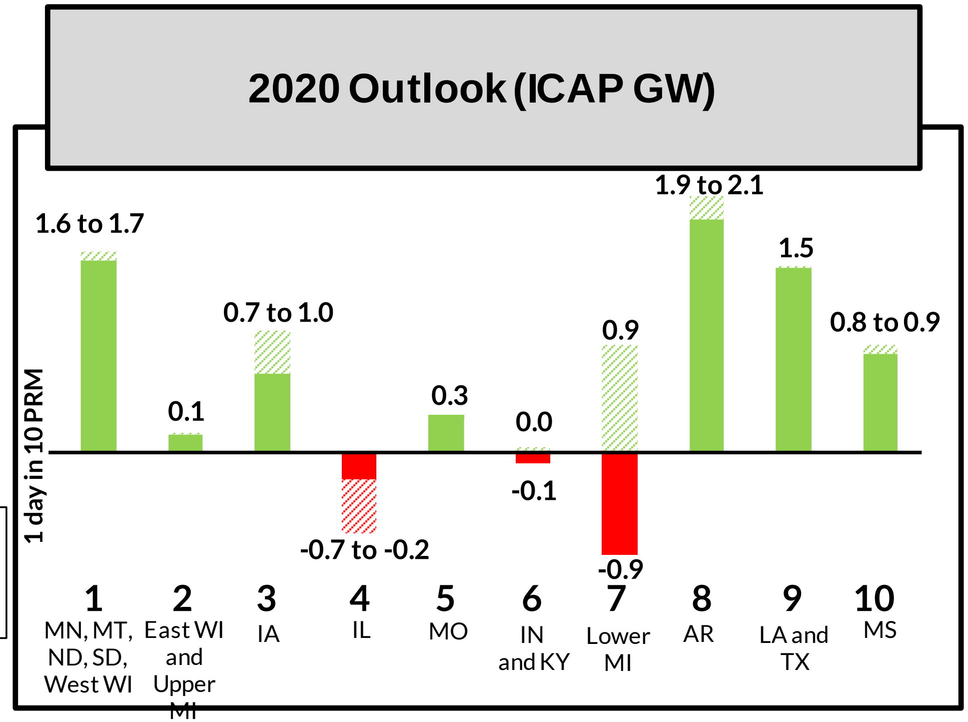
Zone	Capacity Import Limit (CIL), MW		Local Clearing Requirement (LCR), MW	
	2020/21 LOLE	2020/21 PRA	2020/21 LOLE	2020/21 PRA
LRZ-1	3,231	2,902	17,127	17,059
LRZ-2	1,603	1,603	13,259	13,332
LRZ-3	3,406	3,284	7,759	7,672
LRZ-4	6,092	6,003	6,971	6,744
LRZ-5	5,424	5,424	4,283	4,453
LRZ-6	7,188	7,326	13,161	12,778
LRZ-7	3,200	3,200	22,170	21,851
LRZ-8	3,919	3,824	6,247	6,243
LRZ-9	3,712	3,410	20,908	20,894
LRZ-10	3,432	3,160	3,658	3,688

LOLE study capacity was slightly higher than the PRA

Zone	2020/21 LOLE UCAP	2020/21 PRA UCAP	Delta UCAP	Delta (%)
LRZ-1	20,332	20,296	(36)	0%
LRZ-2	14,252	14,056	(196)	-1%
LRZ-3	11,371	10,822	(549)	-5%
LRZ-4	12,128	10,281	(1,846)	-18%
LRZ-5	7,848	7,953	104	1%
LRZ-6	17,846	17,135	(711)	-4%
LRZ-7	22,111	21,728	(384)	-2%
LRZ-8	10,876	10,574	(302)	-3%
LRZ-9	23,090	21,801	(1,289)	-6%
LRZ-10	4,602	5,300	698	13%
External	1,572	1,629	57	3%

In 2020, regional surpluses are sufficient to cover areas with potential resource deficits





- The Michigan Public Service Commission Staff recently filed a report finding that the Michigan LSEs have adequate owned or contracted resources to meet projected resource adequacy requirements through 2022, this aligns with the OMS MISO survey projections for Zone 7
- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint

Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor

LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRR: Local Reliability Requirement
LRZ: Local Resource Zone
LSE: Load Serving Entity
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SS: Self Schedule
SFT: Simultaneous Feasibility Test
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

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Capacity Demonstration Results

Planning Year 2023/24

Case No. U-20590

March 27, 2020

MPSC Staff

Contents

Executive Summary

All Michigan load serving entities (LSE) required to file capacity demonstrations with the Michigan Public Service Commission (MPSC) for planning year 2023/24 pursuant to MCL 460.6w and the August 2019 Commission Order in Case No. U-20590 have filed. Staff has audited the filings, contracts and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2023/24.

Staff projects that the Midcontinent Independent System Operator, Inc. (MISO) Local Resource Zone (LRZ) 7, which consists of the lower peninsula of Michigan, excluding Indiana Michigan Power Company's (I&M) service territory in the southwest corner of the state will have sufficient resources to meet its local clearing requirement (LCR) for the 2020/21 prompt year as well as 2023/24 demonstration year based on the capacity demonstration filings and MISO publications at the time of this report. However, the margins for LRZ 7 with respect to its LCR are projected to be slim and small deviations to resources and/or requirements could leave LRZ 7 short of its LCR. For MISO LRZ 1 and LRZ 2 in Michigan's Upper Peninsula, Staff doesn't have comprehensive enough data to accurately project zonal capacity positions because the majority of these two zones are located in other states not subject to MCL 460.6w. Based on the most recent Organization of MISO States (OMS) Survey, both LRZ 1 and LRZ 2 are projected to have sufficient capacity in 2020 as well as in 2024.[1] Additionally, Staff projects that the I&M service territory in Michigan, which is in PJM Interconnection LLC (PJM), will have sufficient levels of resources available to meet PJM's requirements.

While Staff has seen stagnant growth in aggregated Demand Response (DR) from last year's numbers, it is predicted that these registrations into MISO will grow in the near future. As a result, Staff asks that the Commission support the establishment of procedures or a methodology to facilitate communication between Aggregators of Retail Customers (ARC), Alternative Electric Suppliers (AES), incumbent utilities and Staff when aggregated DR is dispatched on MISO's coincident peak. This is necessary to accurately account for the change in Peak Load Contribution (PLC) if DR resources are dispatched on peak.

[1] 2019 OMS-MISO Survey Results released in June 2019 revised in August, 2019, accessed 03/26/2020.

Background

On September 15, 2017 in Case No. U-18197, the Commission directed all Michigan LSEs to file capacity demonstrations annually pursuant to MCL 460.6w. This report outlines the results of the capacity demonstrations filed for planning year 2023/24 as directed by the Commission in Case No. U-20590 and represents the third annual capacity demonstration report, the prior two being filed in Case No. U-18441 and Case No. U-20154, respectively. In Case No. U-20590, the Commission ordered[2] rate regulated electric utilities[3] to submit capacity demonstrations by December 2, 2019 for the 2023/24 planning year and AESs,[4] cooperatives,[5] and municipal utilities[6] to submit capacity demonstrations in the same docket for the 2023/24 planning year, on or before February 11, 2020.

The purpose of these demonstrations is to ensure that each electric utility owns or has contractual rights to capacity sufficient to meet its capacity obligations as set by the MISO, PJM, or the Commission, as required by MCL 460.6w.

Pre-Demonstration Process

Similar to the previous years, Staff offered LSEs the opportunity to meet with Staff to discuss the capacity demonstration requirements and review relevant materials prior to the final filing deadlines discussed above. A significant number of LSEs met with Staff and clarified the process before filing reports in the docket. Staff found that the pre-filing consultations were helpful in resolving questions prior to filing. Staff will continue to offer pre-filing consultations each year in order to resolve potential issues prior to the filing deadlines.

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[2] August 8, 2019 MPSC Order in Case No. U-20590, accessed 03/23/2020.

[3] Alpena Power Company, Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, Northern States Power Company-Wisconsin, Upper Michigan Energy Resources Corporation, Upper Peninsula Power Company, and Wisconsin Electric Power Company.

[4] AEP Energy Inc, Calpine Energy Solutions LLC f/k/a Noble Americas Energy Solutions LLC, CMS ERM Michigan LCC, Constellation NewEnergy Inc, Dillon Power LLC, Direct Energy Business LLC, Direct Energy Services, EDF Energy Services LLC, Eligo Energy MI, LLC., Energy International Power Marketing Corporation, Energy Services Providers Inc., FirstEnergy Solutions, Interstate Gas Supply LLC, Just Energy Solutions Inc, Liberty Power Delaware LLC, Liberty Power Holdings LLC, MidAmerican Energy Services LLC, Nordic Energy Services LLC, Plymouth Rock Energy LLC, Spartan Renewable Energy, Texas Retail Energy LLC, U.P. Power Marketing LLC, and Wolverine Power Marketing Cooperative Inc.

[5] Bayfield Electric Cooperative, Cloverland Electric Cooperative, Thumb Electric Cooperative, and Wolverine Power Supply Cooperative.

[6] City of Escanaba, City of Stephenson, City of Wakefield, Croswell Light and Power Department, Daggett Electric Department, Michigan Public Power Agency, Michigan South Central Power Agency, Newberry Water and Light Board, and WPPI Energy.

Capacity Demonstration Filings

On or before December 2, 2019, capacity demonstration filings were received from Alpena Power Company, Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation (UMERC), and Upper Peninsula Power Company (UPPCO). The majority of the LSEs filed confidential information under seal as part of the electric utilities' filings. Staff reviewed this information and met with LSEs as needed.

On or before February 11, 2020, capacity demonstration filings were received from Calpine Energy Solutions, LLC., Constellation New Energy Inc., Direct Energy Business, Spartan Renewable Energy Inc., UP Power Marketing, Wolverine Power Marketing Cooperative Inc., City of Escanaba, City of Stephenson, City of Wakefield, Croswell Light and Power Department, Daggett Electric Department, Michigan Public Power Agency, Michigan South Central Power Agency, Newberry Water and Light Board, WPPI Energy, Thumb Electric Cooperative, and Wolverine Power Supply Cooperative. First Energy Solutions Corp, Just Energy Solutions Inc., and Cloverland Electric Cooperative filed their capacity demonstrations on February 12, 2020. Bayfield Electric Cooperative Inc. filed its capacity demonstration on February 17, 2020. Staff confirms receipt of capacity demonstration filing information from, or on behalf of, all LSEs currently serving load in Michigan.

Several AESs filed letters in Case No. U-20590 indicating that they are currently not serving customers in Michigan.[7] Staff confirms that all licensed AESs in Michigan have either filed capacity demonstrations or a letter indicating that they are not currently serving Michigan load.

Staff conducted an audit for each capacity demonstration filing received and requested additional information from the LSE when necessary. Staff has reviewed all contracts included in capacity demonstrations from AES's as well as most of the contracts from co-ops, electric utilities, and municipalities.

Overview of Zonal Adequacy

As alluded to above, there are two regional transmission operators (RTO) in Michigan; MISO and PJM. The majority of Michigan's load is located in MISO. The exception is the southwest corner of the Lower Peninsula which is I&M's service territory located within the PJM RTO. PJM and MISO have different resource adequacy constructs and capacity obligations. PJM has a mandatory three-

[7] Eligo Energy MI, LLC., Liberty Power Holdings LLC, Liberty Power Delaware LLC, Nordic Energy Services LLC, Plymouth Rock Energy LLC, Interstate Gas Supply LLC, Dillon Power LLC, Energy International Power Marketing Corporation, MidAmerican Energy Services LLC, EDF Energy Services LLC, Texas Retail Energy LLC, Energy Services Providers Inc., and AEP Energy Inc.

year forward capacity construct for its LSEs.[8] MISO's capacity construct is for the upcoming year (prompt year) only. Both MISO and PJM LSEs are subject to the requirements of MCL 460.6w requiring sufficient capacity for four years forward: in this case, for planning year 2023/24. PJM LSEs can demonstrate sufficiency simply by providing evidence that the LSE is in compliance with its PJM obligations. MISO LSEs must demonstrate sufficient resources to meet its current prompt year requirement four years forward. For this reason, the majority of this section is focused on MISO.

MISO establishes capacity obligations for all LSEs based on peak load forecasts and a planning reserve margin percentage necessary to meet the North American Electric Reliability Corporation's (NERC) Loss of Load Expectation (LOLE) standard of 1 day in 10 years. LSEs within MISO can meet their capacity requirements either through a Fixed Resource Adequacy Plan (FRAP) or through the Planning Resource Auction (PRA). The PRA is a residual market for LSEs that choose not to use the FRAP or do not have enough capacity resources, either owned or purchased bilaterally, to satisfy their capacity obligations, and thus need to purchase additional resources.

Within MISOs resource adequacy construct, there are two key resource requirements that must both be satisfied to meet the 1 day in 10 years LOLE standard: Planning Reserve Margin Requirement (PRMR) and LCR. The PRMR is determined through LOLE modeling based on the coincident MISO peak forecast and resources adjusted as necessary to meet the 1 in 10 standard. PRMR resources are not location specific, i.e. they can come from outside an LSE's zone. Individual LSEs are responsible for their own share of the zone's PRMR. The ability to use imports to meet PRMR makes it highly likely all zones will meet this requirement. Failure to meet PRMR would only occur if there were not enough resources available within all of MISO's footprint or the resource need for a particular zone exceeded the zones ability to import capacity.

Of greater interest to Staff is the LCR. The LCR is the minimum amount of capacity for an LRZ required to be located within the LRZ to meet the loss of load standard fully accounting for the LRZ's ability to import. The LCR requirement is for the zone as a whole as opposed to a requirement for individual LSEs. There is no LCR requirement applicable to individual LSEs in Michigan pursuant to MCL 460.6w at this time. The LCR is determined by performing a LOLE analysis on each zone individually to determine the Local Reliability Requirement (LRR), which is the amount of resources a zone would need to meet the loss of load standard if it were separated from the rest of MISO. Separately, an import study is performed to determine the Zonal Import Ability (ZIA) for each zone. For LRZ 7, the ZIA is currently (and historically) equal to the capacity import limit (CIL) and the terms are often treated synonymously. The ZIA is then subtracted from the LRR to determine the LCR. If an LRZ doesn't have enough resources to meet its LCR (or PRMR)

[8] PJM's Base Residual Auction is currently suspended. See below for more discussion on this issue. Also, please note, the timing of MISOs and PJM resource adequacy constructs don't align perfectly. PJM's base residual auction, originally intended to occur in May/June 2020, for PY 2023/24 is referred to as being "three years forward" but constitutes the same planning year at issue in U-20590 and the same planning year "four years forward" in MISO's resource adequacy construct (March/April 2020 auction for PY 2020/21).

the PRA clearing price would be set at the Cost of New Entry (CONE) for that year. CONE changes from year to year but for reference, PY 2019/20 CONE was $243.37/MW-Day or ~$89,000/MW-year for LRZ 7. The PRA clearing price being set at CONE would have economic ramifications (LRZ 7 cleared at ~10% of CONE in PY 2019/20) and would provide a signal to stakeholders with responsibilities regarding resource adequacy within the zone. However, it is important to note that MISO's resource adequacy construct is based on probabilistic determinations and failure to meet the requirements of the resource adequacy construct would not mean that the LRZ in question will experience a loss of load event. It simply means the probability of such a loss of load event would exceed the generally accepted criteria that govern the resource adequacy planning process.

In addition to the required compliance year (PY 2023/24), most demonstrations filed included updates for the 2020/21 planning year through the 2022/23 planning year. These updates are voluntary and were not provided by all LSEs[9]. Staff appreciates the efforts made by LSEs to provide updated capacity resource data for these years as it allows Staff to update zonal resource adequacy projections for the prompt year, interim years, as well as the compliance year. It is important to note that the compliance year capacity obligations (PY 2023/24) that are demonstrated for in this case are based off an LSE's prompt year (PY 2020/21) requirement. Changes to load, resources, and MISO procedures in the upcoming years can lead to discrepancies between an LRZ having sufficient capacity to meet its four-year forward Michigan requirements and not having enough capacity to meet MISOs requirements when the prompt year arrives.

MISO – Local Resource Zone 7

Figure 1 shows a comparison of LRZ 7 aggregated resources and MISO resource adequacy requirement projections for the next 4 years. These numbers represent Staff's current projection based on the capacity demonstration filings and MISO publications at the time of this report although, the information is subject to change for all years, including PY 2020/21. Unless otherwise noted resources and resource requirements in this report are in Unforced Capacity (UCAP) Megawatts (MW), equal to Zonal Resource Credits (ZRCs).

[9] The required demonstrations for planning years 2020/2021 and 2021/2022 was made in the 2018 capacity demonstration (Case No. U-18441). The required demonstration for planning year 2022/23 was made in the 2019 capacity demonstration (Case No. U-20154).

Figure 1: U-20590 Results - LRZ 7 Capacity Position (ZRCs)

Line #		PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24
1	Planning Reserve Margin Requirements (PRMR)	21,945	21,847	21,749	21,650
2	Local Reliability Requirement (LRR)	25,051	25,021	24,991	24,961
3	Capacity Import Limit (CIL)	3,200	3,200	3,200	3,200
4	Zonal Import Ability (ZIA)	3,200	3,200	3,200	3,200
5	Local Clearing Requirement (LCR)	21,851	21,821	21,791	21,761
6	Total Owned	16,865	17,193	16,999	16,936
7	Total PPA Contracts	2,753	2,098	2,304	2,493
8	Total ZRC Contracts	608	564	691	822
9	Total Qualified Demand Response	1,352	1,424	1,507	1,558
10	Total Resources (Line 6 + Line 7 + Line 8 + Line 9)	21,578	21,278	21,498	21,809
11	LCR Demonstrated Position (Line 10 - Line 5)	-273	-542	-293	48
12	PRMR Demonstrated Capacity Position (Line 10 - Line 1)	-368	-569	-251	159
13	Net Undemonstrated Zone 7 Capacity	346	391	264	132
14	Anticipated LCR Position (Line 11 + Line 13)	73	-152	-30	180
15	Anticipated PRMR Capacity Position (Line 12 + Line 13)	-21	-178	13	291

(1) PY 2020 PRMR from Preliminary PRA Data. PY 2023 PRMR calculated using the peak demand forecast from the 2020-21 LOLE Study Report and multiplying by the coincidence factor (95%) and reserve margin (108.8%). PY 2021 & PY 2022 calculated through interpolating PY 2020 & PY 2023.

(2) PY 2020 LRR from Preliminary PRA Data. PY 2023 LRR from the 2020-21 LOLE Study Report. PY 2021 & PY 2022 calculated through interpolating PY 2020 & PY 2023.

(3) PY 2020 CIL from the 2020-21 LOLE Study Report, held constant at prompt year value per MISO recommendation.

(4) PY 2020 ZIA from the MISO Preliminary PRA data, held constant at prompt year value per MISO recommendation

(5) LRR-ZIA=LCR

(6-10) Zone 7 resources included in capacity demonstrations sorted by resource type.

(11) LCR position based on demonstrated resources only.

(12) PRMR position based on demonstrated resources only.

(13) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small amount of resources included in the capacity demonstration that Staff expects are no longer available due to recent events.

(14) LCR Position after accounting for undemonstrated Zone 7 Capacity.
(15) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resources to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to in order to meet its PRMR.

Prompt Year (PY 2020/21)

For the prompt year (PY 2020/21), based on preliminary PRA data, Staff expects LRZ 7's PRMR to be 21,945 ZRCs and the LCR to be 21,851 ZRCs. The total LRZ 7 resources included in demonstration filings for the prompt year is 21,578 ZRCs, which would result in the zone being short of the LCR by 273 ZRCs. However, based upon independent information, Staff is aware of capacity resources in Zone 7 that were not included in capacity demonstration filings. Staff projects that an additional 346 ZRCs in LRZ 7, beyond what has been demonstrated for LRZ 7, will be available for the prompt year. Based on the demonstrated resources and projected undemonstrated resources Staff anticipates LRZ 7 will exceed its LCR by approximately 73 ZRCs for the 2020/21 planning year.

Line 12 of Figure 1 outlines the capacity position of LRZ 7 relative to the PRMR. Based on Staff's analysis of LSE filings in this docket, when only demonstrated generation resources physically located within LRZ 7 are considered, there is an expected shortfall of approximately 368 ZRCs in the 2020/21 planning year with respect to the PRMR. With the inclusion of the undemonstrated resources, Staff expects that LRZ 7 will meet its planning year 2020/21 PRMR without importing any ZRCs. While Staff projects that LRZ 7 will meet its prompt-year PRMR without imports, it is likely that some amount of imports will occur in the PRA based upon the relative economics. As a point of reference, the 2019/20 MISO PRA results indicate that LRZ 7 imported 164 ZRCs even though it could have met the PRMR without any imports.

With the thin margins discussed above (especially with respect to the LCR) any changes to forecasts or resources after LSEs filed in this case, but prior to the MISO PRA could result in LRZ 7 not having enough resources to meet the requirements. This would mean the auction clearing price would be set at CONE. This is possible even though all LSEs sufficiently demonstrated resources for PY 2020/21 in 2018 (Case No. U-18441), because of changes to resources, load, and MISO procedures since 2018. A clear example of these changes is the LRZ 7 LCR. The 2018 LCR for LRZ was 20,628 ZRCs[10] and at that time staff projected the LCR for PY 2020/21 to be 20,717 ZRCs[11]. The actual LCR for PY 2020/21 is 21,851 ZRCs, 1,134 ZRCs higher than Staff projected in 2018.

[10] 2018/2019 PRA Results, accessed 3/26/20.
[11] MPSC Staff Report Case No. 18441 filed 3/6/18, accessed 3/26/20

Compliance Year (PY 2023/24)

Staff used the 2020/21 LOLE study report to project requirements for future planning years. These requirements are based on the best available information and are subject to change. The projected PRMR for LRZ 7 for the compliance year (PY 2023/24) is 21,650 ZRCs. Staff determined this number by taking the forecasted peak demand for LRZ 7 in PY 2023/24 (20,931 MW) and accounting for LRZ 7's coincidence factor of 95.07% and the MISO reserve margin of 8.8%. This is a reduction of 295 ZRCs from the prompt year PRMR. Using the LOLE Study Report LRR for PY 2023/24 of 24,961 ZRCs and assuming the ZIA remains constant at 3,200, results in a projected LCR of 21,761 ZRCs for LRZ 7 in PY 2023/24.

Based on the resources included in the capacity demonstration filings for PY 2023/24 (21,809 MW) as well as Staff's estimate (132 MW) of additional LRZ 7 capacity that was not included in the demonstrations and the projected requirements, Staff projects LRZ 7 to have a surplus of 180 MW compared to the projected LCR.

Interim Years (PY 2021/22 & PY 2022/23)

Figure 1 also includes data and projections for the interim years, PY 2021/22 & PY 2022/23. This information is derived using the same methodology as described for the compliance year, interpolating as necessary because the LOLE Study Report didn't provide specific LRZ analysis for the interim years. Comparing those projected requirements to the demonstrated and undemonstrated resources in LRZ 7, results in a capacity shortfall of 152 ZRCs in PY 2021/22 and a shortfall of 30 ZRCs in PY 2022/23 compared to the projected LCRs. This information is based on the best information currently available to Staff, but includes several assumptions and, again, is subject to change. Likely changes include; new forecasts, unknown resource additions or subtractions, changes in generator performance, increased or decreased zonal import ability and/or changes to MISO requirements.

Noteworthy for MISO Local Resource Zone 7

1. Capacity Requirements

Capacity requirements for LRZ 7 for the prompt year as well as future years have not changed significantly from last year's capacity demonstration report.

LRR: The LRR represents the amount of resources required for a particular zone to meet the 1 day in 10 years loss of load standard when modeled as an island (no imports). LRZ 7 had an LRR of 25,023 MWs in the 2019/20 PRA Results. The Preliminary PRA Data for PY 2020 for LRZ 7 shows an LRR of 25,051 MWs. The 2020/21 LOLE Report projects the LRR for PY 2023/24 to be 24,961 MWs.

CIL / ZIA: The ZIA is defined as the ability of an LRZ to import capacity from areas outside of that LRZ. In LRZ 7 the ZIA is equal to the CIL. The 2020 CIL/ZIA is 3,200 compared to 3,211 in 2019. MISO has recommended Staff assume a constant CIL/ZIA for future year projections.

LCR: The LCR is the difference between the LRR and the ZIA. The LCR represents the minimum amount of resources that must be located within a specific zone for that zone to meet the reliability standard. The Preliminary PRA Data for 2020 shows and LCR of 21,851 ZRCs. Last year's LCR was 21,812 ZRCs. Using an the 2020/21 LOLE Report LRR of 24,961 MWs and assuming a ZIA of 3,200 MW results in a projected LCR of 21,761 MW for PY 2023/24.

2. Historical Requirements

Figure 2 below shows data from the annual MISO LOLE study reports for LRZ 7. These numbers typically change slightly prior to the PRA but can be used to see how the capacity requirements have changed over time. Changes in these requirements can have economic and reliability impacts and will continue to be monitored. The preliminary PRA data for 2020 shows a slight decrease in the LRR (25,051 ZRC) and the LCR (21,851 ZRC) compared to the 2020 LOLE Report.[12]

Figure 2: Annual MISO LOLE Report Data

Source	LRR	CIL	LCR (ZRCs)
MISO 2013 LOLE Report	25,305	4,576	20,729
MISO 2014 LOLE Report	24,815	3,884	20,931
MISO 2015 LOLE Report	24,710	3,813	20,897
MISO 2016 LOLE Report	24,715	3,813	21,309
MISO 2017 LOLE Report	24,654	3,320	21,334
MISO 2018 LOLE Report	24,545	3,785	20,760
MISO 2019 LOLE Report	24,845	3,211	21,634
MISO 2020 LOLE Report	25,370	3,200	22,170

The available data from recent PRA results and LOLE reports, as described above, shows a decreasingly small margin between the PRMR and LCR for LRZ 7 as shown in Figure 3.

[12] Figure 1 is based off the best available information at the time of this report. Generally, future years are reported from the latest MISO LOLO Study Report and prompt year data is from more recent Preliminary PRA Data. This may lead to minor differences between Figure 1 and Figure 2.

Figure 3: MISO LRZ 7 LCR & PRMR Comparison

Year	LCR	PRMR	ECIL	Source
PY 2013/14	21055	22702	1647	PRA Results
PY 2014/15	21293	22998	1705	PRA Results
PY 2015/16	21442	22679	1237	PRA Results
PY 2016/17	20851	22406	1555	PRA Results
PY 2017/18	21109	22295	1186	PRA Results
PY 2018/19	20628	22121	1493	PRA Results
PY 2019/20	21812	21976	164	PRA Results
PY 2020/21	21851	21945	94	Preliminary PRA Data
PY 2021/22	21821	21847	26	MPSC Staff Projection
PY 2022/23	21791	21749	-42	MPSC Staff Projection
PY 2023/24	21761	21650	-111	MPSC Staff Projection

The difference between a zones PRMR and its LCR is sometimes referred to as Effective Capacity Import Limit (ECIL). The ECIL is not a MISO defined term and is not representative of a physical import limitation. The ECIL is a product of the MISO resource adequacy construct and is an import limitation only within the constraints of the construct. In order to meet the loss of load standard and avoid the auction clearing price being set at CONE, a zone must have enough resources located within the zone to meet its LCR even if the LCR exceeds the PRMR.

3. Capacity Resource Changes

In addition to expected variation in each generating unit's unforced capacity from year to year, there were a few other noteworthy resource changes this year as compared to last year's report.

Ludington Upgrades

Consumers Energy Company and DTE Electric Company plan to continue upgrades to the Ludington Pumped Storage facility to help support intermittent resources and provide a price hedge against variable market energy prices. The units began undergoing a maintenance overhaul upgrade in 2015, one unit at a time. As of the filing of DTE's Integrated Resource Plan (IRP) in Case No. U-20471, four of the unit upgrades had been completed. A fifth was completed in May 2019. According to DTE's IRP, the $800 million upgrade project to replace each of the six unit turbines in the facility is on schedule to be completed in 2020.[13] Work began on Ludington

[13] MPSC Case No. U-20471, Direct Testimony of Laura J. Mikulan, Exhibit A-3, p. 287.

3, the last unit to be upgraded, in April of 2019 and is expected to be completed by April of 2020, adding 24 ZRCs.[14]

In September 2019, Wolverine Power Supply Cooperative filed a complaint with MISO claiming that the rules governing the PRA were unjust and unreasonable and that the auction failed to establish appropriate price signals.[15] This complaint was due, in part, to the ability of the last of the 6 Ludington units to be offered in as a capacity resource while unavailable during the upgrade. On October 26, 2019, MISO submitted a filing proposing revisions to its tariff to limit the ability of resources to participate in the auction if the resource is expected to have full or partial outages for any 90 (or more) of the first 120 calendar days in the planning year. Federal Energy Regulatory Commission (FERC) accepted MISO's tariff. As Wolverine indicated its support for the tariff, the case was dismissed as moot on January 30, 2020. [16]

Increased Utility Demand Response Programs

Three LRZ 7 LSEs disclosed in their respective capacity demonstration filings new or increasing DR programs for their retail customers. 184 MW of new or increased DR programs were reported by these LSEs in LRZ 7 for the prompt planning year.

Demand Response Aggregation

Pursuant to a Commission Order in Case No. U-18369, the Commission affirmed that AESs may offer DR programs to their customers through a curtailment service provider (CSP) or third-party aggregator.[17] The Commission made this determination in the context of finding that it will continue to review DR programs offered by AESs as part of the capacity demonstration process.

As the Relevant Electric Retail Regulatory Authority (RERRA), the Commission approved the aggregation of 71.4 MWs of DR to be offered into the 2020 MISO capacity market, which is the same as what was approved for the previous year. While still a relatively small percentage of the total capacity, it is expected that aggregated DR will grow in future years. Staff continues to work with CSPs, ARC and MISO to ensure that aggregated DR's PLCMM is properly accounted for when dispatched on MISO's coincident peak. In many cases, the AES is unaware that a

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[14] MPSC Case No. U-20590, Consumer's Energy Company's Capacity Demonstration for Planning Years 2020 Through 2023, p. 1.
[15] FERC Case No. EL19-102, Wolverine Power Supply Cooperative, Inc. v. Midcontinent Independent System Operator, Inc.; Notice of Complaint, Issued October 17, 2019, Accessed 03/23/2020.
[16] FERC Case No. EL19-102, FERC Order Accepting Tariff Filing and Dismissing Complaint as Moot, Docket No. EL19-102, Issued January 30, 2020.
[17] September 15, 2017 MPSC Order in Case No. U-18369, p. 5, accessed 03/23/2019.

customer has offered its DR resource to an ARC, therefore when reporting its PLC, does not know if the DR was called on during MISO's coincident peak. Similarly, the Electric Distribution Company (EDC, the incumbent utility) is also unaware when this aggregated DR is dispatched and unable to make the necessary PLC adjustments, per MISO's tariff.[18] Staff recommends that the Commission support Staff establishing a procedure for communication between the ARC, AES, utility and Staff if aggregated DR is dispatched during the previous coincident peak until such time MISO implements requirements and procedures. This issue is currently being discussed at MISO and may result in tariff modifications subject to FERC approval.[19]

Potential MISO Load Modifying Resource (LMR) Changes

With the increased utilization of LMRs in the MISO footprint, MISO has realized the need to review the capacity accreditation to LMRs given the varying characteristics of these resources. While stakeholder discussions are still ongoing, MISO expects to file this proposal at FERC in late April of 2020.[20] MISO categorizes utility DR programs, aggregated DR, and behind the meter generators (BTMG) (such as large industrial customer and municipal utility generators) as LMRs. MISO currently awards all LMRs the same capacity credit if they can meet the minimum requirements of responding to five events a year over a minimum three-month (June, July and August) period given twelve hours of notice. Documentation is required for resources that meet these minimum requirements, with less documentation required for resources with greater availability and shorter notification times. In addition, LMRs are required to submit a performance test, unless they opt out and are instead subject to a 3x penalty in the case of underperformance during an emergency event.[21] The proposed updates would pro-rate the capacity credit based on the availability to respond to calls (for example: 5-9 calls = 80% credit, 10+ calls = 100% credit) and require a six-hour or less lead-time for LMRs to respond to Maximum Generation events. Currently there are approximately 2,200 MW of LMRs in Michigan LRZ 7 alone. Based on preliminary MISO calculations in its Module E Capacity Tracking Tool, this change would lead to a reduction in the total capacity credit of LMRs in LRZ 7 by 936 MWs, assuming MISO has the correct information and no action is taken by the Michigan Commission or market participants.[22]

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[18] Per MISO's Tariff Module E-1, Section 69A.1.2.
[19] As of March 5, 2020, MISO has incorporated draft Module E-1 language that will likely resolve the EDC information and data sharing barrier, if approved.
[20] Per MISO's Tariff Module E-1, Section 69A.3.5.
[21] Per MISO's Tariff Module E-1, Section 69A.3.5.
[22] Slide 3 of MISO's Liaison Report.

MISO – Local Resource Zone 2

MISO's LRZ 2 encompasses almost the entire Upper Peninsula (UP) of Michigan as well as northern and eastern Wisconsin. MISO LRZ 2 has a CIL of 1,603 ZRCs for planning year 2020/21, but MISO does not define MW capacity imports or export limits between states within the boundaries of the same MISO LRZ. Considering LRZ 2 includes LSEs from Wisconsin (not subject to MCL 460.6w), the data available to Staff for LRZ 2 from capacity demonstration filings is not comprehensive enough to project a zonal capacity position as Staff did in its analysis of LRZ 7. Never-the-less, all Michigan LSEs serving load within MISO LRZ 2 demonstrated sufficient resources to meet their requirements.

Noteworthy for MISO Local Resource Zone 2

MISO determined that there are limitations to the transmission system in the UP that require generation availability to reliably serve all of the load in the UP. The Presque Isle Power Plant which previously provided generation support in the area retired in April of 2019. The plant was owned and operated by Wisconsin Electric and Power Company (WEPCo, which is now Upper Michigan Energy Resources Company (UMERC)). On October 25, 2017, The Commission issued an order approving a certificate of need application by UMERC to build two reciprocating internal combustion engine (RICE) electric generation facilities in Michigan's UP as well as a Retail Large Curtailable Special Contract between WEC Energy Group, INC (UMERC's parent company) and Tilden Mining Company L.C. The RICE units began operation in March 2019.

In its capacity demonstration, UPPCO discussed the mechanical failure and subsequent retirement of its Portage generating unit, one of its two fuel oil generators in the UP, in November of 2018. The company intends to continue operation of the Gladstone fuel oil generator and replace the Portage unit with a solar unit in the UP with a capacity of 125 MW, as approved in its IRP in Case No. U-20350.

American Transmission Company, LLC (ATC) owns and operates the two 138 kV transmission circuits that electronically connect the UP and Lower Peninsula of Michigan. Each of the two circuits consist of three cables. On April 1, 2018, the two transmission circuits tripped offline. The United States Coast Guard led an investigation into the possibility that a passing vessel caused damage to the electric cables which resulted in the two circuits tripping off-line. ATC conducted an underwater inspection of the submarine cables. As of May 1, 2018, one of the two circuits between the UP and Lower Peninsula of Michigan has been restored. There was no transmission connection between the Upper and Lower Peninsula for a short time. ATC was able to maintain system reliability for this time, given the anticipated electric load, while one of the two circuits was reconfigured and energized.

The 2019 OMS-MISO Survey results indicate an installed capacity surplus of 100 MW in the 2020/21 planning year for LRZ 2, increasing to a surplus of 200-800 MW for 2024, for LRZ

2.[23] Notwithstanding the localized reliability issues in the UP, the results of the OMS-MISO Survey indicate that LRZ 2 is projected to have an adequate supply of capacity resources to meet its PRMR requirements for the 2019/20/21 planning years. The UMERC RICE unit capacity replacements and planned capacity replacements by UPPCO, along with and the plans by Cloverland Electric Cooperative and ATC to mitigate the loss of the cable at the Straits, will also have a positive impact on the resource adequacy of the region.

MISO – Local Resource Zone 1

A very small fraction of Michigan's UP load is located in LRZ 1. Northern States Power, Bayfield Electric Cooperative, and the City of Wakefield municipal utility have less than 30 MW combined in MISO LRZ 1. The 2019 OMS-MISO Survey results indicate an installed capacity surplus of approximately 1,600 MW for the 2020 planning year and a similar capacity surplus projected for 2024.[24] LRZ 1 is projected to have an adequate supply of capacity resources to meet its PRMR requirements for the 2020/21 planning year, as well as the next several planning years.

PJM – Indiana Michigan Power Company[25]

As previously stated, PJM has a mandatory forward capacity market for LSEs in its service territory. LSEs in the PJM service territory meet capacity obligations either through participation in PJM's Reliability Pricing Model (RPM) Base Residual Auction (BRA) or through PJM's Fixed Resource Requirement (FRR) plan. As a result of a 2016 complaint, FERC found that PJM's capacity market was unjust and unreasonable due to the Minimum Offer Price Rule's (MOPR) failure to mitigate out of market payments that threaten the competitiveness of the PJM's capacity market. After several years and several rounds of proposals, in December 2019 FERC rejected most of the filed solutions in favor of an expanded MOPR and directed PJM to file a compliance filing by March 18, 2020.[26]

Due to the uncertainty at PJM over the capacity market proceedings with FERC, PJM has not conducted a BRA since 2018 for Delivery Years 2021/2022. PJM has suspended the 2022/2023 BRA, which would have originally run in May 2019, until FERC approves its March 2020 compliance filing. The length of this delay will depend on how swiftly FERC takes action and how compressed the upcoming auction schedules are. At a minimum, several auctions will be delayed though Delivery Year 2025/2026.

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[23] 2019 OMS-MISO Survey Results released in June 2019 revised in August, 2019, accessed 03/17/2020.
[24] *Id.*
[25] Indiana Michigan Power Company is an electric operating company of American Electric Power Company, Inc. (AEP). I&M is a wholly owned subsidiary of AEP and is operated as a single utility in the American Electric Power System (AEP System).
[26] FERC Directs PJM to Expand Minimum Offer Price Rule, December 19, 2019, accessed 03/22/2020.

The capacity demonstration process and requirements approved by the Commission in Case No. U-20154[27] allow PJM LSEs to file an amended capacity demonstration two weeks after the completion of the PJM RPM BRA. In light of the pending FERC MOPR decision, I&M was unable to update its capacity demonstration last year. Staff worked with the Company this year and I&M was able to submit a capacity demonstration based on its projection of owned-resources and capacity contracts for the 2023/2024 planning-year without an updated BRA.

I&M's most recent capacity demonstration filed in Case No. U-20590 indicates that the Company plans to continue with the PJM FRR plan that allows them to opt out of participation in the PJM competitive capacity market baring any major FERC ordered changes. Based on this, I&M's capacity position should not be greatly affected by decisions resulting from FERC's MOPR. Nevertheless, this delays the Company's ability to provide, with 100% certainty, an indication of where future planning year capacity will come from to make up small differences between owned-resources and short-term market purchases.

The Commission order in Case No. U-16090 set I&M's customer choice cap amount to zero, and was subsequently reset to ten percent on February 1, 2019 pursuant to the Commission order and MCL 460.10a(1)c. On February 1, 2019, I&M began enrolling customers in its choice program and is now fully subscribed at the cap. Currently I&M is responsible for the capacity of its choice load in its FRR plan under the PJM RAA. If suppliers were to choose to self-supply capacity, then that capacity would also need to be included in I&M's FRR plan. Constellation NewEnergy Inc. is currently the only AES serving load in I&M's service territory.

Indiana Michigan Power Company's capacity demonstration indicates that it has already satisfied PJM's requirements for planning years 2019/20 through 2021/22 and that it expects to meet PJM's requirements for planning year 2023/24. I&M reports that its expectation to meet the PJM requirements for the 2023/24 planning year is due to PJM resources in July 2019, though I&M notes that the outcome of a pending decision related to its Rockport facility could impact I&M's capacity plan going forward.

[27] September 13, 2018 MPSC Order in Case No. U-20154, accessed 03/14/2018.

Figure 4: Indiana Michigan Power Company Capacity Demonstration Summary

Item	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24
Total Planning Reserve Margin (expected reserves), UCAP MW	4,339	4,325	4,386	4,386
Total Company Owned Generation, MW	4,053	3,993	4,034	3,392
Total Demand Response Resources (treated as capacity), UCAP MW	251	304	369	369
Total PPA, UCAP MW	225	223	280	625
Total Planning Resources, MW	4,529	4,520	4,684	4,386
UCAP Surplus / (Shortfall), MW	190	195	297	0

In addition to I&M's capacity demonstration, Staff also reviewed information for approximately 231.9 MW of cooperative and municipal utility obligations in the Michigan portion of PJM's territory for planning year 2023/24.

Based upon its review, Staff expects that the LSEs in the Michigan portion of PJM will continue to meet the PJM capacity obligations based on information included in individual capacity demonstrations and the current level of surplus capacity in the PJM market. With such an abundance of reserve resources, if I&M were to encounter an unanticipated shortfall in the immediate future, Staff expects that it could easily be accommodated through the procurement of some amount of these reserve resources through market purchases. As market conditions may change over time, Staff will continue to monitor the resource adequacy of the PJM region overall as well as the capacity plans of Michigan LSE's located within the PJM territory. Staff will continue to monitor I&M's capacity plans and expects to work with the Company to update its capacity demonstration after PJM's next BRA. As reaffirmed in the Company's Integrated Resource Plan filed in Case No U-20591[28] Staff does not anticipate I&M to have any issues meeting capacity obligations.

LSE Capacity Demonstration Results (PY 2023/24)

Staff appreciates the time and effort made by all Michigan LSEs to comply with the provisions of MCL 460.6w, as well as to comply with the questions, audits, contract reviews, and requests for additional information throughout this process. The LSE capacity demonstration results are reported for planning year 2023/24 because, following the initial capacity demonstration which covered four years, only the fourth year forward is required for compliance. As previously described in its September 15, 2017 order in Case No. U-18197, the Commission requested a table be included in this report that identifies the capacity by type for each individual electric provider

[28] MPSC Case No. U-20591, Direct Testimony of John Torpey, p. 15.

without revealing the identity of any specific electric provider. The requested table with a breakdown for each electric provider that filed a capacity demonstration is included as Appendix A. In addition to the breakdown by individual supplier, Staff reports the following aggregate results in Figure 5 below.

Figure 5: Resource Breakdown (%) by Supplier Type Planning Year 2023/24

Supplier Type	Owned	DR	Contract - PPA	Contract - ZRC	Auction
Muni/Co-Op Aggregate	79.1%	0.1%	16.6%	3.8%	0.3%
AES Aggregate	16.5%	0.0%	7.4%	75.6%	0.5%
Utility Aggregate	75.4%	9.1%	15.3%	0.0%	0.0%

Demand Response

As part of its analysis, Staff reviewed the LSEs' DR programs as an optional source of capacity. When used, a reduction in demand through DR programs offsets a portion of an LSE's capacity needs. LSEs can utilize interruptible DR during critical peak times to quickly respond to bulk electric system needs which can delay future capital investment in new generation. Behavioral DR programs allow the utility to lower its peak demand forecast, thus mitigating the need for an equal of amount supply side resources.

Demand response played a prominent role in LSEs' integrated resource plan filings, where DR is required to be considered along with traditional supply side resources for meeting capacity needs. MCL 460.6t directs Staff to complete a statewide study of DR potential in Michigan every five years, and the most current state of Michigan demand response potential study was issued on September 29, 2017.[29] In addition, the Commission approved Michigan Integrated Resource Planning Parameters on November 21, 2017 in Case No. U-18418 that include provisions regarding including DR options in future integrated resource plans.

By planning year 2023/24, Consumers Energy is forecasting increased DR levels to support capacity through the expansion of existing programs. The DR levels assumed in both Consumers Energy's and DTE Electric's integrated resource plans are reflected in their capacity demonstration filing. Consumers Energy is offering its new Bring Your Own Device program for residential customer classes to deliver and manage significant peak load reductions. DTE Electric has a forecasted growth in three of its DR programs, Dynamic Peak

[29] State of Michigan Demand Response Potential Study Technical Assessment, Applied Energy Group, September 29, 2017, accessed 03/22/2020.

Pricing, Programable Controllable Thermostat, and Bring Your Own Device. Staff will continue to monitor these plans and the use of DR in Michigan for the foreseeable future.

ZRC Contracts

Last year, Staff recommended that forward ZRC contracts to be utilized for capacity demonstration purposes specify delivery of the ZRCs in the MISO Module E Capacity Tracking (MECT) tool prior to the applicable PRA auction. All new forward ZRC contracts were audited by Staff this year, and all complied with Staff's requested delivery terms, allowing Staff to audit the ZRC transfers each year prior to the PRA. Figure 5 indicates a slight decrease in the percentage of ZRC contracts utilized this year by the utilities and the AESs, and a slight increase in the amount utilized by municipal utilities and cooperatives.

An important thing to note is that ZRCs are defined in MISO's tariff and are created in the prompt year when UCAP for supply-side and demand-side resources are converted into ZRCs in the MISO MECT. ZRCs for any year further out than the prompt year are projected and don't become "real" ZRCs until the prompt year. ZRCs are fungible products that can be sold or transferred, and in some cases, sold more than once. The characteristics of ZRCs allow for them to be easily traded and tracked within the MISO MECT. MISO has a view into the source of ZRCs and transfers of those ZRCs that occur prior to the PRA in the prompt year, and those ZRC transfers are audited by Staff as a secondary check on the ZRC contracts utilized in the capacity demonstrations.

At this point in time, the overall amount of ZRC contracts included in capacity demonstration filings do not impact Staff's ability to continue to make forward resource adequacy projections on a zonal basis. Staff will continue to monitor and audit ZRC contracts and ZRC transfers within the MECT going forward.

AES Load Switching

For this year's report, there were no AESs that were required to file an amended or supplemental capacity demonstration. Similar to last year, Staff requested that any AES who experienced load switching during this time provide a signed affidavit confirming the increase or reduction in their load compared to the PLC data provided by the utility with their capacity demonstration that contained the amount of load switching for each planning year. Each supplier contracting for additional customer load provided a copy of its affidavit confirming this transaction to the supplier that was losing the load to be accounted for in both suppliers' demonstrations. For this filing year, all of the load switching had occurred prior to the filing date.

LSE Compliance with Capacity Demonstration Requirements

All LSEs that filed capacity demonstrations in Case No. U-20590 have met the requisite levels of planning resources for planning year 2023/24. Staff highlights a few issues that it will continue to monitor in the next section.

Other Issues

On March 31, 2018, FirstEnergy Solutions Corp. (FES), which was granted an Alternative Electric Supplier license on January 8, 2002, filed a voluntary petition for relief pursuant to Chapter 11 of Title 11 of the United States Code. Concurrent with the March 31st filing, FES filed, with the bankruptcy court, a number of first day motions pursuant to which it sought authorization to continue operating in the normal course of business. Each of these motions were granted after hearing by the bankruptcy court. FES has continued to serve its Michigan customer base under a business as usual scenario and has filed a sufficient capacity demonstration in this case. On February 27, 2020, FES emerged from Chapter 11 bankruptcy under a new name, Energy Harbor LLC ("Energy Harbor"). Importantly, FES did not transfer or assign its license, but instead will simply operate under the new Energy Harbor name and under the same EIN/Duns number. Energy Harbor LLC will continue to honor its existing customers' contractual rights.

Conclusion and Recommendations

All Michigan load serving entities required to file capacity demonstrations with the Michigan Public Service Commission for planning year 2023/24 pursuant to MCL 460.6w and the August 2019 Commission Order in Case No. U-20154 have filed. Staff has audited the filings, contracts and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2023/24.

Staff appreciates the cooperation of all Michigan LSEs with respect to this process and the willingness to provide sensitive data and answer questions necessary for Staff to complete its review. Staff opines that the process continues to become more efficient for both Staff and LSEs. To help accommodate further process efficiency improvements for future capacity demonstrations Staff has the following recommendation as stated below.

Staff asks that the Commission support the establishment of procedures or methodologies to facilitate communication between ARCs, AESs, incumbent utilities and Staff when aggregated DR is dispatched on MISO's coincident peak. This is necessary to accurately account for the change in PLC if DR resources are dispatched on MISO's coincident peak. As discussed above, MISO's proposed tariff language would help to mitigate this issue, but it is unknown when MISO will receive FERC approval, therefore Staff would like to develop a process prior to MISO's coincident peak this summer.

Appendix A

Figure 6: Planning Year 2023/24 Resource Breakdown (%) by Individual Supplier[30]

LSE	Owned	DR	Contract - PPA	Contract - ZRC	Auction
Supplier 1	49%	51%	0%	0%	0%
Supplier 2	0%	0%	78%	22%	0%
Supplier 3	33%	31%	36%	0%	0%
Supplier 4	84%	9%	7%	0%	0%
Supplier 5	0%	0%	0%	100%	0%
Supplier 6	95%	0%	4%	1%	0%
Supplier 7	95%	0%	4%	1%	0%
Supplier 8	0%	0%	99%	0%	1%
Supplier 9	67%	8%	24%	1%	0%
Supplier 10	0%	0%	0%	98%	2%
Supplier 11	83%	0%	17%	0%	0%
Supplier 12	100%	0%	0%	0%	0%
Supplier 13	0%	0%	100%	0%	0%
Supplier 14	0%	0%	0%	100%	0%
Supplier 15	9%	7%	84%	0%	0%
Supplier 16	95%	0%	4%	1%	0%
Supplier 17	0%	0%	0%	100%	0%
Supplier 18	47%	0%	11%	37%	5%
Supplier 19	65%	9%	27%	0%	0%
Supplier 20	0%	0%	0%	99%	1%
Supplier 21	0%	0%	100%	0%	0%
Supplier 22	90%	8%	1%	0%	0%
Supplier 23	0%	0%	100%	0%	0%
Supplier 24	0%	0%	0%	100%	0%
Supplier 25	33%	0%	67%	0%	0%
Supplier 26	0%	0%	100%	0%	0%
Supplier 27	0%	0%	100%	0%	0%
Supplier 28	77%	0%	0%	23%	0%
Supplier 29	0%	0%	0%	100%	0%

[30] Suppliers (municipal and cooperative electric utilities) that combined their capacity resources are shown as one supplier in the above figure. The total number of suppliers may vary from year to year based on changes to which suppliers combine their capacity demonstrations as well as new suppliers or suppliers no longer serving load in Michigan.

Consumers Energy
Count on Us

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Writer's Direct Dial Number: (517) 788-1846
Writer's E-mail Address: robert.beach@cmsenergy.com

March 2, 2020

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

RE: MPSC Case No. U-20734 – In the matter of the application of Consumers Energy Company for approval of an amendment to power purchase agreements.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Consumers Energy Company's Application and Testimony and Exhibits of Company witness David F. Ronk, Jr**. This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service showing service upon the parties.

Sincerely,

Digitally signed by Robert W. Beach
Date: 2020.03.02 14:51:53 -05'00'

Robert W. Beach

cc: Steven Hughey

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of an Amendment to Power Purchase Agreement.	)))))	Case No. U-20734

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") requests the Michigan Public Service Commission ("MPSC" or the "Commission") to grant approval, pursuant to Section 6j of 1982 Public Act ("PA") 304 ("Act 304"), MCL 460.6j, and other applicable law, of an amendment to the Company's Power Purchase Agreement ("PPA") with Entergy Nuclear Power Marketing, LLC ("Entergy"). In support of this request, Consumers Energy states as follows:

1. Consumers Energy is, among other things, engaged as a public utility in the business of generating, purchasing, distributing, and selling electric energy to approximately 1.8 million retail customers in the state of Michigan. The retail electric system of Consumers Energy is operated as a single utility system, within which uniform rates are charged.

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Commission pursuant to certain provisions of 1939 PA 3, as amended by various acts, including 1982 PA 304, 2000 PA 141, and 2016 PA 341, MCL 460.1 *et seq*.; 1909 PA 106, as amended, MCL 460.551 *et seq*.; 1909 PA 300, as amended, MCL 462.2 *et seq*.; and 2008 PA 286, MCL 460.4a *et seq*.

3. On July 11, 2006, the Company entered a PPA with Entergy Nuclear Palisades, LLC to purchase virtually all of the output from the Palisades Nuclear Plant ("Palisades Plant") for a period of 15 years commencing on the date that the sale of the Palisades Plant from Consumers Energy to Entergy Nuclear Palisades, LLC closed, April 11, 2007.[1] The Palisades Plant has nominal capacity of approximately 780 megawatts ("MW") and has produced approximately 6.5 million megawatt hours ("MWh") of energy per year. Among other features, the PPA provided for a purchase price for delivered capacity and energy that began at $43.50/MWh in 2007 with fixed annual adjustments resulting in a price in 2022 of $61.50/MWh, as provided in Exhibit A of the PPA. The specific price paid for energy delivered by the Palisades Plant in each month is the product of the annual price and "shaping factors," as provided in Exhibit C of the PPA, and under certain conditions replacement energy can be provided in the event the Palisades Plant experiences a derate or outage, as provided in Section 2.4 of the PPA. The PPA was approved by the Commission in Case No. U-14992.[2]

4. On December 7, 2016, Entergy and the Company entered an agreement to amend the PPA ("Amendment No. 1") that would have had the effect of terminating the PPA on May 31, 2018. The Company was unable to secure the necessary regulatory approvals for Amendment No. 1 and the Amendment was declared void *ab initio* on September 27, 2017. The details associated with the Amendment No. 1 were provided in Case No. U-18250.

[1] The PPA was assigned by Entergy Nuclear Palisades, LLC to an affiliate company, Entergy Nuclear Power Marketing, LLC (referred to in this Application as "Entergy"), on December 15, 2006.

[2] The Company's PPA with Entergy was filed in Case No. U-14492 as Exhibit A-1 (WEG-1).

5. On January 28, 2020, the Company and Entergy reached agreement on a second amendment to the PPA ("Amendment No. 2") that would extend the PPA by 51 days from April 11, 2022 to May 31, 2022. Amendment No. 2 mitigates the potential that the Company would be required to purchase replacement capacity for Midcontinent Independent System Operator, Inc. ("MISO") Planning Year 2021 (i.e. June 1, 2021 through May 31, 2022) and establishes a fixed price for energy in lieu of the variable price to which the Company would otherwise be exposed.

6. Because the current term of the PPA expires 51 days prior to the end of MISO Planning Year 2021 on May 31, 2022, there is a risk that not extending the PPA, as is proposed in Amendment No. 2, could result in MISO requiring the Company to provide replacement capacity through the end of MISO Planning Year 2021. If the Company were unable to provide replacement capacity, it could result in a significant expense to the Company and its customers. The Company has determined that the potential exposure for such a result is approximately $20 million.

7. In the event the PPA is not extended 51 days and the Company is required to purchase replacement capacity for Planning Year 2021, and is unable to do so, there could also be adverse system reliability impacts. If the Company is required to provide replacement capacity for MISO Planning Year 2021, it would be likely that Entergy will have sold the capacity from the Palisades Plant to another entity that needed the capacity to maintain its Planning Reserve Margin Requirement ("PRMR"). If the Company is unable to purchase replacement capacity, then it is likely that MISO Local Resource Zone ("LRZ") 7, the zone in which the Palisades Plant is located and which comprises most of the lower peninsula of Michigan, is capacity deficient and unable to import additional capacity to satisfy the PRMR of load serving entities located within LRZ 7. Amendment No. 2 mitigates this adverse system reliability impact as the Company will be in a position to offer the capacity provided by the Palisades Plant into the MISO Planning Year 2021

Planning Resource Auction ("PRA") as a resource available to serve LRZ 7 market participant customers.

8. Under the current PPA, the energy and capacity charges paid by the Company to Entergy are set forth in Exhibit A of the PPA. In Amendment No. 2, the Parties have agreed to replace Exhibit A of the PPA with a new version of Exhibit A that provides the energy and capacity charges for the 51-day period between April 11, 2022 and May 31, 2022. The total capacity and energy price to be paid under Amendment No. 2 is $24.14/MWh of Delivered Energy. Furthermore, with respect to the 51-day extension period, Amendment No. 2 proposes to: (i) remove the Shaping Factors used for calculating the energy and capacity charges in the current PPA; and (ii) remove the Entergy's rights and obligations to provide the Company with Replacement Energy and Replacement Capacity and/or Accredited Capacity.

9. The Company has performed a customer value analysis of Amendment No. 2 and has determined a value of the capacity and energy to be purchased from Entergy for the 51-day extension period. Specifically, the Company evaluated projected capacity and energy prices against the capacity and energy prices for the 51-day extension period and determined that Amendment No. 2 will provide a savings to customers. The results of this analysis are provided in Exhibit A-3 (DFR-3).

10. In requesting approval of Amendment No. 2, the Company is not asserting that it has a capacity need during MISO Planning Year 2021. In its December 2, 2019 report filed in Case No. U-20590, the Company provided its capacity needs for MISO Planning Years 2020 through 2023 and demonstrated that, even without the capacity provided by the Palisades Plant, for MISO Planning Year 2021, the Company has 56 ZRCs of surplus capacity. Nevertheless, the Company continues to have an obligation under its participation in the MISO markets to avoid

capacity withholding and to offer available resources into the PRA. Because the PPA will be effective for the first 10 months of MISO Planning Year 2021, MISO rules require the Company to either use the capacity to offset its own PRMR or offer the capacity into the PRA. If the Company's PRA offer clears; that is if one or more market participants purchase the capacity, that market participant will be expecting the capacity to be available to cover the market participant's PRMR for the entire year. Amendment No. 2 ensures that capacity will be available by securing capacity from the Palisades Plant for the entire 2021 MISO Planning Year.

11. Furthermore, because the current term of the PPA, prior to Amendment No. 2, resulted in the Palisades Plant not being included in the Company's capacity portfolio during MISO Planning Year 2021, the Company and its customers are paying for capacity during the balance of MISO Planning Year 2021 (the 314-day period) for which they are not receiving MISO credit. By extending the PPA by 51 days, at energy and capacity rates which are expected to provide a cost savings, Amendment No. 2 ensures that the Company and its customers receive credit in MISO for capacity for the 314-day period that they are already paying for, as well as the 51-day period to which Amendment No. 2 applies.

12. In conjunction with this Application, the Company is filing testimony and exhibits from Company witness David F. Ronk, Jr., Executive Director for Contract Projects. The Company is also filing a copy of the recently executed PPA amendment as Exhibit A-2 (DFR-2). The accompanying testimony and exhibits are an integral part of this Application and are incorporated by reference in this Application as if fully set forth herein. Consumers Energy is requesting Commission approval of Amendment No. 2 to the PPA between the Company and Entergy pursuant to Section 6j of Act 304 and all other applicable law.

13. It is necessary for the approval of the relief requested in this Application to be granted by December 31, 2020 so that the Company may make appropriate arrangements for 2021 MISO Planning Year. Paragraph 4 of Amendment No. 2 provides that it is a condition precedent to the Amendment Effective Date that the Company obtain Regulatory Approval on or before December 31, 2020. The reason for this requirement is that if the Company is unable to secure regulatory approval of Amendment No. 2 then alternate arrangements need to be made before the start of MISO Planning Year 2021. Therefore, the Company is requesting an expedited proceeding which provides a timely resolution of this matter.

WHEREFORE, Consumers Energy Company respectfully requests the Michigan Public Service Commission to grant the following relief:

(A) Grant approval of Amendment No. 2 and specifically indicate that the Commission approves the recovery by Consumers Energy Company of all payments under the Power Purchase Agreement with Entergy Nuclear Power Marketing, LLC, as amended, for the purposes of Section 6j of 1982 PA 304, MCL 460.6j, and all other applicable law;

(B) Determine that the relief requested herein should be granted on an expedited basis; and

(C) Grant Consumers Energy such other and further relief as may be lawful and appropriate.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Digitally signed by Timothy J. Sparks
Date: 2020.03.02 14:52:41 -05'00'

Dated: March 2, 2020 By: ______________________

Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

Digitally signed by Robert W. Beach
Date: 2020.03.02 14:53:06 -05'00'

____

Robert W. Beach (P73112)
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Jackson, Michigan 49201
(517) 788-1846

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **Consumers Energy Company** for approval of an Amendment to Power Purchase Agreement.	)))))	Case No. U-20734

VERIFICATION

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Timothy J. Sparks, being first duly sworn, deposes and says that he is the Vice President of Electric Grid Integration of Consumers Energy Company; that he has executed the foregoing Application for, and on behalf of, Consumers Energy Company; that he has read the foregoing Application and is familiar with the contents thereof; that the facts contained therein are true, to the best of his knowledge and belief; and that he is duly authorized to execute such Application on behalf of Consumers Energy Company.

Tim Sparks

Digitally signed by Timothy J. Sparks
Date: 2020.03.02 14:53:28 -05'00'

Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

Subscribed and sworn to before me this 2nd day of March, 2020.

Crystal L. Chacon

Digitally signed by Crystal L. Chacon
Date: 2020.03.02 14:53:50 -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

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for approval of an Amendment to	)	Case No. U-20734
Power Purchase Agreement.	)	
	)	

DIRECT TESTIMONY

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2020

DAVID F. RONK, JR.
DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is David F. Ronk, Jr. I maintain an office at 1945 West Parnall Road, Jackson, Michigan.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director for Contract Projects in the Electric Supply Department.

Q. Please describe your educational background and work experience.

A. I earned a Bachelor of Science in Engineering degree from the University of Michigan in 1975. I have been employed by Consumers Energy beginning in January 1976 in a variety of positions with my most recent responsibilities associated with managing the Company's portfolio of Power Purchase Agreements ("PPA"). I have been licensed to practice Engineering in the state of Michigan since February 1980.

Q. What are your responsibilities as Executive Director for Contract Projects?

A. My responsibilities include negotiating and administering various PPAs on behalf of Consumers Energy and its customers.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have provided testimony before the Commission in approximately 50 cases. A listing of those cases is provided as Exhibit A-1 (DFR-1).

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to advise the Commission of an amendment ("Amendment No. 2") to the Company's PPA with Entergy Nuclear Power Marketing, LLC ("Entergy") (collectively "the Parties") and request approval of Amendment No. 2 purusant to Section 6j of 1982 Public Act 304, MCL 460.6j, and other applicable law.

Q. How is the remainder of your direct testimony organized?

A. My direct testimony: (i) describes certain aspects of the PPA; (ii) discusses a previous amendment to the PPA; (iii) describes and discusses Amendment No 2; and (iv) discusses the benefits of Amendment No. 2 and other considerations.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-1 (DFR-1)	Previously Sponsored Testimony Before the Michigan Public Service Commission;
Exhibit A-2 (DFR-2)	Agreement to Amend the Palisades Nuclear Power Purchase Agreement between Entergy Nuclear Power Marketing, LLC and Consumers Energy Company; and
Exhibit A-3 (DFR-3)	Market Value Determination.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

<u>PPA</u>

Q. Describe the Company's PPA with Entergy.

A. On July 11, 2006, the Company entered a PPA with Entergy Nuclear Palisades, LLC to purchase virtually all of the output from the Palisades Nuclear Plant ("Palisades Plant") for a period of 15 years commencing on the date that the sale of the Palisades Plant from Consumers Energy to Entergy Nuclear Palisades, LLC would close. The sale of the Palisades Plant closed on April 11, 2007. The Palisades Plant has nominal capacity of approximately 780 megawatts ("MW") and has produced approximately 6.5 million megawatt hours ("MWh") of energy per year. Among other features, the PPA provides for a purchase price for delivered capacity and energy that began at $43.50/MWh in 2007 with fixed annual adjustments resulting in a price in 2022 of $61.50/MWh, as provided in Exhibit A of the PPA. The specific price paid for energy delivered in each month and for on-peak and off-peak hours is the product of the annual price and "shaping factors" as provided in Exhibit C of the PPA. Under certain conditions Entergy Nuclear Palisades, LLC has the option to provide replacement energy in the event the Palisades Plant experiences a derate or outage, as provided in Section 2.4 of the PPA. The PPA was approved by the Commission in Case No. U-14992.[1]

Q. Has the PPA been subsequently modified?

A. Yes. The PPA was assigned by Entergy Nuclear Palisades, LLC to Entergy (Entergy Nuclear Power Marketing, LLC), an affiliate company, on December 15, 2006. Furthermore, the PPA has been amended twice.

<u>Amendment No. 1</u>

Q. Please describe Amendment No. 1 to the PPA.

A. On December 7, 2016, Entergy and the Company entered an agreement to amend the PPA ("Amendment No. 1") that would have had the effect of terminating the PPA on May 31, 2018. The Company was unable to secure the necessary regulatory approvals for Amendment No. 1 and the Amendment was declared void *ab initio* on September 27, 2017. The details associated with the Amendment No. 1 were provided in Case No. U-18250.

[1] The Company's PPA with Entergy was filed in Case No. U-14492 as Exhibit A-1 (WEG-1).

Amendment No. 2

Q. Please describe Amendment No. 2 to the PPA.

A. On January 28, 2020, the Company and Entergy reached agreement on a second amendment to the PPA ("Amendment No. 2") that would extend the PPA by 51 days from April 11, 2022 to May 31, 2022. Amendment No. 2 mitigates the potential that the Company would be required to purchase replacement capacity for Midcontinent Independent System Operator, Inc. ("MISO") Planning Year 2021 (i.e. May 31, 2021 through June 1, 2022) and establishes a fixed price for energy in lieu of the variable price to which the Company would otherwise be exposed.

Q. Please explain why the PPA was set to expire prior to May 31, 2022, the end of MISO Planning Year 2022.

A. As explained above, the PPA was originally executed on July 11, 2006, in conjunction with the Plant sale transaction. At that time, the current MISO Planning Year construct, which involves a capacity planning year that begins on June 1 and continues through May 31 of the following year, did not exist. The current MISO Planning Year construct did not formally begin until 2008. Therefore, in defining the terms of the PPA in the bid solicitation and negotiating the terms of the PPA, the Company and its advisors were unable to anticipate MISO's Planning Year construct and thus were not able to align the term of the PPA with what is now the current MISO Planning Year construct.

Q. In the event the Company had not negotiated Amendment No. 2 with Entergy and was required to purchase replacement capacity for the last 51 days of MISO Planning Year 2021 what expense would it incur?

A. Generally, when a capacity resource that either was included in a Fixed Resource Adequacy Plan ("FRAP") or cleared in the Planning Resource Auction ("PRA") retires or is no longer available to provide resource adequacy service to MISO in a Planning Year, MISO requires the generator to provide replacement capacity. The tariff is not clear what occurs with respect to a Load Serving Entity ("LSE") if a PPA originally included in the LSE's capacity portfolio is included in a FRAP or clears in the PRA, then terminates during a Planning Year and the generator subsequently elects to contract with another LSE to cover the second LSE's Planning Reserve Margin Requirement ("PRMR") in that same Planning Year. Presumably, MISO would require the initial LSE to provide replacement capacity similar to the tariff requirements placed on a non-performing generator.

Additionally, the tariff is not clear what remedy would occur if the generator or LSE was unable to provide replacement capacity for the balance of the planning year. The tariff addresses a comparable situation where a new resource is unavailable at the beginning of the planning year and the Market Participant is assessed the "ICAP Deferred Non-Compliance Charge" or a charge equal to the auction clearing price plus Cost of New Entry ("CONE") for each MW of capacity cleared in the PRA if included in a FRAP but unavailable at the beginning of the planning year. Presumably MISO (or the Federal Energy Regulatory Commission on behalf of MISO) would apply a similar charge if replacement capacity was unavailable at the end of a planning year as well.

The expense the Company would incur in purchasing replacement capacity for the last 51 days of MISO Planning Year 2021 cannot be determined with certainty at this time. However, if the Company failed to provide replacement capacity to MISO it may be exposed to MISO charges of CONE plus the PRA Clearing Price. The maximum PRA Clearing Price is CONE, so conceivably the MISO charges could be as high as twice CONE. For MISO Planning Year 2020, CONE is $94,000/MW-year or $10.73/ZRC-hour. Two times CONE would be $188,000/MW-year or $21.46/ZRC-hour. Fifty-one days times 780 ZRCs times 24 hours per day times $21.46/ZRC-hr would result in a potential exposure of approximately $20 million.

Of course, there is not 100% certainty: that MISO would require replacement capacity to be provided by the Company; that the Company would fail to provide replacement capacity; what the PRA Clearing Price for MISO Planning Year 2021 will be; and what CONE for MISO Planning Year 2021 will be. However, there still remains a risk that not extending the PPA through Amendment No. 2 could result in a significant expense for the Company and its customers if MISO requires the Company to provide replacement capacity.

Q. In the event the Company is required to purchase replacement capacity for MISO Planning Year 2021, and is unable to do so, will there be adverse system reliability impacts?

A. Yes. If the Company is required to provide replacement capacity for MISO Planning Year 2021, it would be likely that Entergy will have sold the capacity from the Palisades Plant to another entity that needed the capacity to maintain its PRMR. If the Company is unable to purchase replacement capacity then it is likely that MISO Local Resource Zone ("LRZ")

7, the zone in which the Palisades Plant is located and which comprises most of the lower peninsula of Michigan, is capacity deficient and unable to import additional capacity to satisfy the PRMR of load serving entities located within LRZ 7.

Q. Does Amendment No. 2 mitigate the potential adverse system reliability impact described above?

A. Yes. To the extent the Palisades Plant is operating through May 31, 2022, and the Company performs its obligations under the PPA, Entergy will not have the ability to sell the capacity from the Palisades Plant to other entities. Therefore, the Company will be in a position to offer the capacity provided by the Palisades Plant into the MISO Planning Year 2021 PRA as a resource available to serve LRZ 7 market participant customers.

Q. What occurs if the Palisades Plant is not operating in the period prior to May 31, 2022?

A. As between the Company and Entergy, Entergy retains the sole responsibility to determine whether the Palisades Plant operates or initiates maintenance or retirement activities. Section 10.2 of the PPA provides Entergy with certain rights to terminate the PPA in the event continued operation of the Facility is no longer feasible, prudent and/or sustainable. Amendment No. 2 does not change Section 10.2 of the PPA. If termination under Section 10.2 were to occur, the timing of such termination would have a bearing on MISO's requirements for the provision of replacement capacity. Generally, MISO rules will not require replacement capacity to cover a forced outage occurring within the last two months prior to the planned retirement of a generating facility and therefore, the Company is not of the position that a forced outage occurring during the extended term provided under Amendment No. 2 would likely trigger a need for replacement capacity from MISO.

Q. What price has the Company agreed to pay Entergy under Amendment No. 2?

A. Under Paragraph 5(b) of Amendment No. 2, the Parties have agreed to replace Exhibit A of the PPA with a new Exhibit A that is included as page 8 of Amendment No. 2. As shown on Exhibit A contained in Amendment No. 2, for the 51-day period between April 11, 2022, and continuing for the remainder of the term of the contract, the total capacity and energy price to be paid is $24.14/MWh of Delivered Energy.

Q. Does Delivered Energy include Replacement Energy during the 51-day extension period provided for in Amendment No. 2?

A. No. In Paragraph 5(c) of Amendment No. 2, the Parties have agreed to suspend Entergy's rights and obligations to provide the Company with Replacement Energy and Replacement Capacity and/or Accredited Capacity from the Palisades Plant, as set forth in Section 2.4 of the PPA. While Section 2.4 was the result of the bid and negotiation resulting in the sale of the Palisades Plant in 2007, it did not apply to the negotiations for the 51-day extension.

Q. Do the Shaping Factors that appear in Exhibit C apply during the 51-day period provided for in Amendment No. 2?

A. No. The Shaping Factors that appear in Exhibit C of the PPA are intended to apply to the annual values that appear in Exhibit A so as to provide a monthly on-peak and off-peak price for each MWh of Delivered Energy. The price negotiated for the 51-day extension period considered the value of energy and capacity expected to receive in April and May 2022 and thus, the Shaping Factors that appear in Exhibit C would not apply. In Paragraph 5(d), the Parties agreed to exclude any adjustment by the Shaping Factors for calculating the Capacity Charge and the Energy Charge applicable for the 51-day extension period.

<u>Benefits of Amendment No. 2 and Other Considerations</u>

Q. What is the value of the capacity purchased under Amendment No. 2?

A. During the negotiation of Amendment No. 2, the Company analyzed the value of the capacity to be purchased under Amendment No. 2 and determined that the capacity has a value of approximately 10% of CONE. In Planning Year 2019, the PRA Clearing Price for LZR 7 was $24.30/ZRC-day or approximately 10% of 243.37/ZRC-day, the MISO Planning Year 2019 CONE. Amendment No. 2 Exhibit A attributes $24.34/ZRC-day or 10% of the 2019 Planning Year CONE to capacity value. Based on the amount of energy expected to be delivered during the 51-day period $24.34/ZRC-day is estimated[2] to be equivalent to $1.04/MWh of delivered energy and thus $1.04/MWh in value of the $24.14/MWh total price is attributable to capacity. Of course, if LZR 7 becomes constrained the value of capacity will approach or equal CONE. The calculation of the value of the capacity purchased under Amendment No. 2 is provided in Exhibit A-3 (DFR-3).

Q. What is the value of the energy purchased under Amendment No. 2?

A. During the negotiation of Amendment No. 2, the Company analyzed the value of the energy to be purchased under Amendment No. 2 and determined that the value of the energy to be delivered by the Palisades Plant under Amendment No. 2 during April and May 2022 to be approximately $23.60/MWh. Due to the timing of the amendment negotiations, the Company's analysis was based on a November 2019 energy forecast. Amendment No. 2 Exhibit A attributes $23.10/MWh of the $24.14/MWh total price to energy, or about $0.50/MWh less than the Company's November 2019 forecast for energy

[2] For this analysis EFORd is assumed to be negligible resulting in ZRCs being equal to MW of capacity.

of $23.60/MWh. The calculation of the value of the energy purchased under Amendment No. 2 is provided in Exhibit A-3 (DFR-3).

Q. Does the Company have a need for this Capacity?

A. No. In its December 2, 2019 report filed in Case No. U-20590, the Company provided its capacity needs for MISO Planning Years 2020 through 2023. Exhibit 2 of that report demonstrates that for MISO Planning Year 2021 (i.e. June 1, 2021 through May 31, 2022), the Company has 56 ZRCs of surplus capacity. Prior to resolving the issue associated with Amendment No. 2, the Company has assumed that capacity associated with the final partial Planning Year of the PPA for the output of the Palisades Plant was potentially uncertain and therefore, the Company excluded the capacity from its planning portfolio for the final partial Planning Year. This is demonstrated on row 19 of Exhibit 2 from the Company's filing in Case No. U-20590 which shows a reduction of 794 ZRCs from Planning Year 2020 to Planning Year 2021 consisting of non-intermittent, in-state PPA resources. Of the 794 ZRCs assumed to be reduced in Planning Year 2021, 780 ZRCs are attributed to the Palisades Plant, and 14 ZRCs are attributed to a PPA that is expiring for another plant but which is assumed to be contracted for a new term. The 14 ZRCs are included in the amounts shown on line 27 of Exhibit 2 from the Company's filing in Case No. U-20590.

Q. If the Company does not have a need for this capacity why should the Company incur the expense associated with Amendment No. 2?

A. While the Company made a conservative assumption regarding its capacity portfolio it continues to have an obligation under its participation in the MISO markets to avoid capacity withholding and to offer available resources into the PRA. Because the PPA will be effective for the first 10 months of MISO Planning Year 2021, MISO rules require the

Company to either use the capacity to offset its own PRMR or offer the capacity into the PRA. If the Company's PRA offer clears; that is if one or more market participants purchase the capacity, that market participant will be expecting the capacity to be available to cover the market participant's PRMR for the entire year, hence the need for Amendment No. 2 to provide for capacity for the entire planning year.

Q. Are there any other benefits related to extending the PPA which the Commission should consider?

A. Yes. As explained above, the PPA, prior to Amendment No. 2, was not included in the Company's capacity portfolio because the term of the PPA did not run for the entire MISO Planning Year 2021. This means that the Company and its customers are paying for capacity during the balance of MISO Planning Year 2021 (the 314-day period) for which they are not receiving MISO credit for. By extending the PPA by 51 days at energy and capacity rates which are expected to provide a cost savings, Amendment No. 2 ensures that the Company and its customers receive credit in MISO for capacity for the 314-day period that they are already paying for as well as the 51-day period to which Amendment No. 2 applies.

Q. Does Amendment No. 2 require approval by a certain date?

A. Yes. Paragraph 4 of Amendment No. 2 provides that it is a condition precedent to the Amendment Effective Date that the Company obtain Regulatory Approval on or before December 31, 2020. The reason for this requirement is that if the Company is unable to secure regulatory approval of Amendment No. 2 then alternate arrangements need to be made before the start of MISO Planning Year 2021. For the most part the Company and Entergy will need to begin communicating various aspects of their MISO Planning Year

2021 portfolio to MISO in mid-February 2021. If Entergy retains the rights to the capacity for the last 51 days of MISO Planning Year 2021 the Company would want to advise MISO and the Independent Market Monitor of the situation and assure that any offer of the facility into the PRA was consistent with MISO's tariff and mitigate the Company's exposure to Replacement Capacity Expense.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
Consumers Energy Company	)	
for approval of an Amendment to	)	Case No. U-20734
Power Purchase Agreement.	)	
	)	

EXHIBITS

OF

DAVID F. RONK, JR.

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2020

PREVIOUSLY SPONSORED TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. MPSC Case No. U-10710-R (direct and rebuttal), the Company's 1995 Power Supply Cost Recovery ("PSCR") Reconciliation case, regarding the treatment of sulfur dioxide emission allowances;

2. MPSC Case No. U-10973-R (direct), the Company's 1996 PSCR Reconciliation case;

3. MPSC Case No. U-11180 (rebuttal), the Company's 1997 PSCR Plan case, regarding the treatment of sulfur dioxide emission allowances and certain permit conditions;

4. MPSC Case No. U-12488 (direct and rebuttal), regarding certain terms and conditions of service for retail open access customers;

5. MPSC Case No. U-13917 (direct, supplemental, and rebuttal), the Company's 2004 PSCR Plan case, regarding electric capacity requirements; the appropriate calculation of energy payment rates under certain qualified facility contracts, and the appropriate treatment of third-party sales revenues in calculating PSCR costs;

6. MPSC Case No. U-14031 (direct, rebuttal, and supplemental rebuttal), regarding the calculation of the hold harmless amount associated with the proposed resource conservation plan;

7. MPSC Case No. U-14274 (direct and rebuttal), the Company's 2005 PSCR Plan case, regarding electric capacity requirements and costs for 2005;

8. MPSC Case No. U-14347 (direct), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2006 test year and power supply cost for the five-year period 2005 through 2009;

9. MPSC Case No. U-13917-R (direct), the Company's 2004 PSCR Reconciliation case, regarding power supply costs incurred in 2004;

10. MPSC Case No. U-14701 (direct, supplemental and rebuttal), the Company's 2006 PSCR Plan case, regarding electric capacity requirements and costs for 2006;

11. MPSC Case No. U-14274-R (direct and supplemental), the Company's 2005 PSCR Reconciliation case, regarding power supply costs incurred in 2005;

12. MPSC Case No. U-15001 (direct), the Company's 2007 PSCR Plan case, regarding electric capacity requirements and costs for 2007;

13. MPSC Case No. U-15245 (direct and supplemental), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2008 test year and power supply cost for the five-year period 2007 through 2011;

14. MPSC Case No. U-14701-R (direct and supplemental), the Company's 2006 PSCR Reconciliation case, regarding power supply costs incurred in 2006;

15. MPSC Case No. U-15290 (direct and supplemental), regarding the Company's balanced energy initiative;

16. MPSC Case No. U-15415 (direct), the Company's 2008 PSCR Plan case, regarding electric capacity requirements and costs for 2008;

17. MPSC Case No. U-15001-R (direct and supplemental), the Company's 2007 PSCR Reconciliation case, regarding power supply costs incurred in 2007;

18. MPSC Case No. U-15645 (direct and rebuttal), regarding operating and maintenance expense and capital cost associated with electric and fuel supply for 2009 test year and power supply cost for the seven-year period 2007 through 2013;

19. MPSC Case No. U-15675 (direct), regarding the Company's 2009 PSCR Plan, regarding electric capacity requirements and costs for 2009;

20. MPSC Case No. U-15805/U-15889 (direct and rebuttal), regarding the 2009 renewable energy plan and energy optimization plan;

21. MPSC Case No. U-15415R (direct and rebuttal), the Company's 2008 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2008;

22. MPSC Case No. U-16045 (direct and rebuttal), the Company's 2010 PSCR Plan, regarding electric capacity requirements and costs for 2010;

23. MPSC Case No. U-16191 (direct and rebuttal), regarding Operating and Maintenance expense and Capital cost associated with Electric and Fuel Supply for the test year ended June 30, 2011 and Power Supply cost for the 12-month period ended June 30, 2011;

24. MPSC Case No. U-15675R (direct, rebuttal, supplemental rebuttal, and second supplemental rebuttal), the Company's 2009 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2009;

25. MPSC Case No. U-16300 (direct and rebuttal), the Company's 2009 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2009;

26. MPSC Case No. U-16432 (direct and second rebuttal), the Company's 2011 PSCR Plan, regarding electric capacity requirements and costs for 2011;

27. MPSC Case No. U-16543 (direct and rebuttal), the Company's application for approval of a Renewable Energy Plan amendment;

28. MPSC Case No. U-16794 (direct), regarding Operating and Maintenance expense and Capital costs associated with Energy Supply Operations for the test year ended September 30, 2012;

29. MPSC Case No. U-16045R (direct and rebuttal), the Company's 2010 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2010;

30. MPSC Case No. U-16301 (direct), the Company's 2010 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2010;

31. MPSC Case No. U-16890 (direct and supplemental), the Company's 2012 PSCR Plan, regarding electric capacity requirements and costs for 2012;

32. MPSC Case No. U-16581 (direct), the Company's application for biennial review of its Renewable Energy Plan;

33. MPSC Case No. U-16432R (direct), the Company's 2011 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2011;

34. MPSC Case No. U-16655 (direct), the Company's 2011 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2011;

35. MPSC Case No. U-17087 (direct and rebuttal) regarding capacity planning matters associated with the test year beginning January 1, 2013;

36. MPSC Case No. U-17095 (direct and rebuttal) regarding the Company's 2013 PSCR Plan, specifically addressing electric capacity requirements and costs for 2013;

37. MPSC Case No. U-16890R (direct), the Company's 2012 PSCR Reconciliation Case, regarding Power Supply Costs incurred in 2012;

38. MPSC Case No. U-17301 (direct and supplemental), the Company's 2013 Application for biennial review of the Renewable Energy Plan, regarding various changes to the Renewable Energy Plan;

39. MPSC Case No. U-17321 (direct), the Company's 2012 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2012;

40. MPSC Case No. U-17429 (direct), the Company's application for a certificate of necessity associated with the construction of a natural gas-fueled combined cycle electric generating unit located in Thetford Township, Genesee County, Michigan;

41. MPSC Case No. U-17317 (direct, supplemental, and rebuttal) regarding the Company's 2014 PSCR Plan, specifically addressing electric capacity requirements and costs for 2014;

42. MPSC Case No. U-17496 (direct and rebuttal) regarding long-term power purchase auction procedures;

43. MPSC Case No. U-17631 (direct and rebuttal), the Company's 2013 Renewable Cost Reconciliation Case, regarding renewable energy costs incurred in 2013;

44. MPSC Case No. U-17678 (direct and rebuttal) regarding the Company's 2015 PSCR Plan, specifically addressing electric capacity requirements and costs for 2015;

45. MPSC Case No. U-17725 (direct and rebuttal) regarding the acquisition of long-term capacity contracts for MISO Planning years 2015 through 2020;

46. MPSC Case No. U-17735 (direct and rebuttal) regarding the expenses associated with power supply issues for the test year beginning June 1, 2015;

47. MPSC Case No. U-17792 (direct) regarding the Company's 2015 Application for biennial review of the Renewable Energy Plan, regarding various changes to the Renewable Energy Plan;

48. MPSC Case No. U17918 (direct and rebuttal) regarding the Company's 2016 PSCR Plan specifically addressing electric capacity requirements and costs for 2016;

49. MPSC Case No. U-17990 (direct and rebuttal) regarding the expenses associated with power supply issues for the test year beginning September 1, 2016;

50. MPSC Case No. U-18142 (direct, second supplemental, and rebuttal) regarding the Company's 2017 PSCR Plan specifically addressing electric capacity requirements and costs for 2017;

51. MPSC Case No. U-18250 (direct) regarding the Company's application to securitize certain costs associated with amending the Company's Power Purchase Agreement with Entergy Nuclear Power Marketing, LLC, specifically, actions taken by the Company to replace capacity otherwise being provided by the Company's Power Purchase Agreement with Entergy Nuclear Power Marketing, LLC.

52. MPSC Case No. U-17981 (direct) regarding the Complaint of the Independent Power Producers Coalition of Michigan against the Company concerning alleged violations of Public Utility Regulatory Policy Act of 1978 and related Commission Orders; and

53. MPSC Case No. U18392 (direct and rebuttal) regarding the Company's application for Approval of Amendment No. 2 of the Power Purchase Agreement between the Company and T.E.S. Filer City Station Limited Partnership.

Agreement to Amend the Palisades Nuclear Power Plant Power Purchase Agreement between Entergy Nuclear Power Marketing, LLC and Consumers Energy Company

This Agreement to Amend (the "Agreement to Amend") the Palisades Nuclear Power Plant Power Purchase Agreement dated as of July 11, 2006 (the "PPA") is made and entered into as of January 28, 2020 (the "Execution Date"), by and among Entergy Nuclear Power Marketing, LLC, a Delaware limited liability company ("Seller"), and Consumers Energy Company, a Michigan corporation ("Buyer"). Buyer and Seller are sometimes collectively referred to as the "Parties" and individually a "Party". All capitalized terms used in this Agreement to Amend, but not otherwise defined herein, shall have the meanings set forth in the PPA.

WHEREAS, Entergy Nuclear Palisades, LLC ("ENP") and Buyer entered into the PPA and, pursuant to Section 16.3 of the PPA, on December 1, 2006, ENP assigned to Seller all of its right, title and interest in, to and under the PPA, and Seller assumed and agreed to undertake to pay, perform and discharge when due all obligations of Seller to Buyer as of that date, and

WHEREAS, the Parties have agreed on certain terms under which an amendment to the PPA will become effective as of the Amendment Effective Date (as defined in Section 1 below).

NOW THEREFORE, for good and valuable consideration the receipt and sufficiency of which is acknowledged by each of the Parties, the Parties agree as follows:

1. Defined Terms Used in this Agreement to Amend.

(a) "Amendment Effective Date" shall mean ten (10) Business Days after the final MPSC order meeting all of the requirements stated in the definition of "Buyer's Required Regulatory Approval" is no longer subject to appeal, or Buyer's waiver of such appeal condition.

(b) "Amendment Payment" shall mean the collective amount of any payments due from Buyer to Seller under the PPA that are applicable to the period beginning at 12:00:00 a.m. EST on April 11, 2022 and extending through and including the Termination Date as defined in the PPA.

(c) "Buyer's Required Regulatory Approval" shall mean (i) a final order is issued by the Michigan Public Service Commission (the "MPSC") pursuant to 1982 PA 304 MCL 460.6j, as amended, and other applicable laws of the state of Michigan: (A) affirming that Buyer's payment of the Amendment Payment is reasonable and prudent; (B) providing approval for Buyer to fully recover the Amendment Payment from its customers; (C) in all other respects reasonably satisfactory to Buyer, and (D) the terms and conditions of such final order shall not directly or indirectly impose any obligation on Seller in addition to the PPA and this Agreement, and (ii) unless Buyer waives this clause by written notice to Seller, such final order shall not be subject to further appeal. Unless, within eight (8) Business Days of issuance of the final MPSC order, Buyer gives written notice to Seller that conditions (i)(A)-(C) above have not been satisfied (including reasonable detail as to the basis for a determination under (C)) or Seller gives notice to Buyer that condition (i)(D) above has not been satisfied, each of such conditions shall be deemed fulfilled.

2. **Representations and Warranties of the Parties as of the Execution Date.** As of the Execution Date:

(a) Each of the Parties represents and warrants to the other Party that:

(i) It has all corporate power and authority to enter into and perform this Agreement to Amend, and to carry out the transactions contemplated herein.

(ii) The execution, delivery and performance of this Agreement to Amend, have been duly authorized by, and are in accordance with, its articles of incorporation and by-laws; this Agreement to Amend has been executed and delivered on its behalf by the signatory so authorized; and this Agreement to Amend constitutes its legal, valid and binding obligation, enforceable against it in accordance with the terms hereof.

(iii) Execution, delivery and performance of this Agreement to Amend (A) will not result in a breach or violation of, or constitute a default under, any Authorization, or any contract, lease or other agreement or instrument to which it is a party, or by which it or its properties may be bound or affected; and (B) does not require any Authorization, or the consent, authorization or notification of any other Person, or any other action by or with respect to any other Person (except for Authorizations and consents or authorizations of other Persons already obtained, notifications already delivered, or other actions already taken).

(iv) No suit, action or arbitration, or legal, administrative or other proceeding is pending or has been threatened against it that would affect the validity or enforceability of this Agreement to Amend or its ability to perform its obligations hereunder in any material respect, or that would, if adversely determined, have a material adverse effect on its business or financial condition. There is no bankruptcy, insolvency, reorganization, receivership or other arrangement proceedings pending against or being contemplated by it, or, to its knowledge, threatened against it.

(v) It is not in breach of, in default under, or in violation of, any applicable Law, or the provisions of any Authorization, or in breach of, in default under, or in violation of, any provision of any promissory note, indenture or any evidence of indebtedness or security therefor, lease, contract, or other agreement by which it is bound, except for any such breaches, defaults or violations which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on its business or financial condition or its ability to perform its obligations hereunder.

(vi) Other than the Buyer's Required Regulatory Approval, the amendment to the PPA set forth in Section 5 below (as of the Amendment Effective Date) (A) will not result in a breach or violation of, or constitute a default under, any Authorization, or any contract, lease or other agreement or instrument to which it is a party, or by which it or its properties may be bound or affected; and (B) does not require any Authorization, or the consent, authorization or notification of any other Person, or any other action by or with respect to any other Person (except for Authorizations and consents or authorizations of other Persons already obtained, notifications already delivered, or other actions already taken).

(b) Seller represents and warrants to Buyer that it has not determined that the operation of the Facility has become materially and economically adverse such that continued operation of the Facility is no longer feasible, prudent and/or sustainable in accordance with the PPA.

3. Covenants of the Parties.

(a) As of and after the Execution Date:

(i) Buyer will use its reasonable efforts to secure Buyer's Required Regulatory Approval as promptly as practicable, and will keep Seller informed of all material aspects of the regulatory approval process.

(ii) Seller will use its reasonable efforts to cooperate with Buyer, and will provide any information or consent that Buyer reasonably deems necessary, in order to allow Buyer to secure Buyer's Required Regulatory Approval. Upon request, Seller will provide reasonable assistance for Buyer's efforts to demonstrate the reasonableness and prudence of this Agreement to Amend before the MPSC and in any related appeals.

4. Condition Precedent to the Amendment Effective Date. It is a condition precedent to the Amendment Effective Date that Buyer shall have obtained Buyer's Required Regulatory Approval.

If the condition precedent set forth in this Section 4 is not satisfied on or before December 31, 2020, unless the Parties agree in writing to extend such date, this Agreement to Amend shall be null and void, and the Parties will have no further obligations or liabilities under this Agreement to Amend, except that Buyer shall take such steps as necessary to withdraw any application or materials it has submitted requesting Buyer's Required Regulatory Approval, and, to the extent reasonably possible and subject to any regulatory conditions or applicable retention policies, return to Seller any such materials provided by Seller.

5. Amendment to the PPA.

(a) As of the Amendment Effective Date, Section 10.1 ("Term") of the PPA is deleted in its entirety and the following is substituted in lieu thereof:

"**10.1. Term** Subject to the terms and conditions of this Agreement, including the final approval of the Michigan Public Service Commission ("MPSC"), this Agreement shall commence on the Effective Date, and shall continue in effect until 11:59:59 p.m. (EST) on May 31, 2022 (the "Termination Date"), unless terminated earlier as expressly provided herein."

(b) As of the Amendment Effective Date, Exhibit A ("Capacity and Energy Charges") of the PPA is deleted in its entirety and the Exhibit A ("Capacity and Energy Charges") attached hereto and incorporated herein by reference as Attachment 1 is substituted in lieu thereof.

(c) As of the Amendment Effective Date, the following is added to Section 2.4:

"(g) Exception. Notwithstanding any other provision of this Agreement, during the period on and from 12:00:00 a.m. EST on April 11, 2022, to the end of the Term, Seller's rights and obligations to provide Buyer with Replacement Energy and Replacement Capacity and/or Accredited Capacity from the Facility as set forth in Section 2.4 during a Derate with a duration of more than one (1) day, including a Derate caused by a Scheduled Maintenance Outage, a Summer Maintenance Outage, or any other scheduled outage of the Facility is suspended."

(d) As of the Amendment Effective Date, the following is added to Section 3.1:

"(d) Shaping Factors. Notwithstanding any other provision of this Agreement, during the period on and from 12:00:00 a.m. EST on April 11, 2022, to the end of the Term, the Capacity Charge and the Energy Charge shall not be adjusted by the Capacity and Energy Charge Shaping Factors set out in Exhibit C hereto."

6. Termination Upon Plant Retirement. If prior to the Amendment Effective Date Seller gives notice of an election under Section 10.2 of the PPA to permanently retire the Facility, with such permanent retirement to occur prior to the Amendment Effective Date, then if this Agreement to Amend has not previously been terminated pursuant to Section 4, this Agreement to Amend will terminate as of the permanent retirement date specified in such notice.

7. General Provisions for the Agreement to Amend.

(a) For the avoidance of doubt:

(i) If either Party assigns or transfers any or all of its rights, title or interest in the PPA in accordance with Section 16.2 of the PPA after the Execution

Date, and whether or not the Amendment Effective Date has occurred, this Agreement to Amend shall thereafter be deemed to have been executed by, and shall apply with equal force as between, the Parties and such permitted assignee.

(ii) Nothing in this Agreement to Amend or in the PPA, as amended as of the Amendment Effective Date, should be construed as, or constitutes, a commitment to either continue to operate the Facility or to shut down the Facility as of any particular date.

(b) The terms and provisions of this Agreement to Amend and the PPA, as so modified as of the Amendment Effective Date, are binding on and inure to the benefit of and are enforceable by the successors and assigns permitted in and by Article XVI of the PPA. For the avoidance of doubt, except as modified by this Agreement to Amend as of the Amendment Effective Date, the PPA remains in full force and effect according to its terms.

(c) This Agreement to Amend will not be construed against either Party as a result of the preparation, drafting, negotiation or execution hereof.

(d) This Agreement to Amend and the rights and obligations of the Parties hereunder shall be governed by and construed in accordance with the law of the State of Michigan (without giving effect to conflict of law principles) as to all matters, including but not limited to matters of validity, construction, effect, performance and remedies. The Parties' agreements and waivers set forth in Article VI (Force Majeure), Article VII (Events of Default; Remedies), Article XIII (Notices) and Article XIV (Confidentiality), and in Sections 1.2 (Rules of Interpretation), 17.1 (Dispute Resolution), 17.3 (Compliance with Laws), 17.4 (Taxes and Other Charges), 17.7 (Governing Law; Venue), 17.8 (Entire Agreement; Amendment), 17.9 (No Implied Waiver), 17.10 (Severability), 17.12 (Expenses), 17.13 (Counterparts), 17.14 (Survival), 17.15 (Third Party Beneficiary) and 17.16 (Mobile Sierra), of the PPA shall govern this Agreement to Amend as if all references therein to the PPA were to this Agreement to Amend.

[Remainder of Page Intentionally Blank – Signature Page to Follow.]

IN WITNESS WHEREOF, each of the Parties has caused this Agreement to Amend to be executed on its behalf by its duly authorized officer as of the Execution Date first set forth above.

ENTERGY NUCLEAR POWER MARKETING, LLC

By: Barrett E. Green

Name: Barrett E. Green

Title: President and Chief Financial Officer TGW DMW

CONSUMERS ENERGY COMPANY

By: Patricia K. Poppe

Name: Patricia K. Poppe

Title: President and Chief Executive Officer

Review and Approvals		
Contracts	KGT	1-16-2020
Risk	CBR	1-22-2020
Legal	AES	1/21/2020

JRA 01/23/2020
01/24/2020
01/27/2020

Attachment 1

Exhibit A

Capacity and Energy Charges

EXHIBIT A

Capacity and Energy Charges

Year	Energy Charge (in $/MWh)	Capacity Charge (in $/MWh)	Total (in $/MWh)
2007	38.15	5.35	43.50
2008	38.59	5.41	44.00
2009	39.03	5.47	44.50
2010	40.12	5.63	45.75
2011	41.22	5.78	47.00
2012	42.32	5.93	48.25
2013	42.97	6.03	49.00
2014	43.85	6.15	50.00
2015	44.73	6.27	51.00
2016	46.04	6.46	52.50
2017	47.36	6.64	54.00
2018	48.67	6.83	55.50
2019	49.99	7.01	57.00
2020	51.30	7.20	58.50
2021	52.62	7.38	60.00
2022, up to and including the hour ending at 11:59:59 p.m. EST on April 10, 2022	53.94	7.56	61.50
2022, beginning at 12:00:00 a.m. EST on April 11, 2022 and continuing thereafter	23.10	1.04	24.14

Except as provided in the following sentence, for each month during the Term, the Capacity Charge and the Energy Charge set forth above shall be adjusted by multiplying the amount of such charge by the applicable Shaping Factor for such month as set forth on Exhibit C hereto. Notwithstanding any other provision of this Agreement, during the period on and from 12:00:00 a.m. EST on April 11, 2022, to the end of the Term, pursuant to Section 3.1(d) of this Agreement, the Capacity Charge and the Energy Charge shall not be adjusted by the Capacity and Energy Charge Shaping Factors set out in Exhibit C hereto.

Case No: U-20734
Exhibit No: A-3 (DFR-3)
Page: 1 of 1
Witness: DFRonk
Date: February 2020

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

AMENDMENT No. 2 to POWER PURCHASE AGREEMENT between ENTERGY NUCLEAR POWER MARKETING and CONSUMERS ENERGY COMPANY

MARKET VALUE DETERMINATION

	(a)	(b)	(c)	(d)	(e)	(f)
			April 2022	May 2022	51-Day Period (Total)	($/MWh)
	Energy Value (2019 10+2 Forecast)					
1	LMP (Mich Hub)	($/MWh)	24.90	24.55		
2	Estimated Congestion (Mich Hub to Palisades)	($/MWh)	-0.81	-1.27		
3	LMP (Palisades)	($/MWh)	24.09	23.28		
4	Days in Period	(days)	20	31	51	
5	Hours in Period	(hrs)	480	744	1224	
6	Output during Period	(MWh/hr)	787.2	780.2		
7	Availablity		0.975	0.975		
8	Volume of Energy	(MWh)	368,410	565,957	934,367	
9	Value	($)	8,874,987	13,175,481	22,050,468	
10	Average Unit Value	($/MWh)				23.60
	Capacity Value					
11	PY 2019 Cost of New Entry (LRZ 7)	($/MW-Yr)			88,830	
12	Period Length	Days/Yr			365	
13	PY 2019 Cost of New Entry (LRZ 7)	($/MW-day)			243.37	
14	Economic Withholding Conduct Threshold	($/MW-day)				24.34
15	Capacity	(MW)			780	
16	Period Length	(days)			51	
17	Value of Capacity	($)			968,125	
18	Average Unit Value	($/MWh)				1.04
	Capacity and Energy Value					
19	Energy Value	($ and $/MWh)			22,050,468	23.60
20	Capacity Value	($ and $/MWh)			968,125	1.04
21	Total	($ and $/MWh)			23,018,593	24.64
	Capacity and Energy Cost					
22	Cost	($ and $/MWh)			22,555,612	24.14
	Estimated Savings					
23	Savings	($ and $/MWh)			462,982	0.50

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Page **1** of **1**

Question:

2. Refer to your response to MEC-CE-47(a), and further refer to the Company's December 2, 2019 capacity demonstration filing in Case No. U-20590.
a. Please provide a copy of confidential Exhibits 4, 6, 8, 10, and 11 from the Company's December 2, 2019 filing.
b. Does the Company's projection of its capacity position anticipate that the Palisades PPA termination date will be extended from April 11, 2022, until May 31, 2022?
i. If so, please describe any efforts to extend the termination date of the Palisades contract.
ii. If not, please explain why the Company is not pursuing an extension of this PPA, and/or why such extension would not be feasible.

Response:

Objection by Counsel: The Company objects to the production of confidential Exhibits 8, 10, and 11 from the Company's December 2, 2019 filing in Case No. U-20590 because these documents contain competitive and commercially sensitive information concerning the Company's generation fleet and generators which the Company contracts to purchase from. The disclosure of this information, even under the Protective Order entered in this case, could be used to gain a competitive advantage over the Company's generating fleet and the generators that the Company contracts to purchase from. Furthermore, the Company objects to the production of Exhibits 8, 10, 11 because the information contained in those files is historical MISO data which is irrelevant to and beyond the scope of this rate case proceeding. Providing Exhibits 8, 10, and 11 is not proportional to the needs of this case.

Subject to this objection, and without waiving it, the Company is providing confidential Exhibits 4 and 6 from the Company's December 2, 2019 filing in Case No. U-20590 with this discovery response. These confidential exhibits will only be provided subsequent to the execution of a suitable confidentiality and nondisclosure agreement.

(a) Please see U20697-MEC-CE-1009-Troyer-CONF_ATT_1 and U20697-MEC-CE-1009-Troyer-CONF_ATT_2 for the requested Confidential Exhibits from Case No. U-20590.

(b) The Company's projection in Case No. U-20590 does not include capacity from Palisades in the 2021 Planning Year. The exhibits in Case No. U-20590 were made prior to January 28, 2020 when the Company and Entergy reached an agreement on a second amendment to the power purchase agreement ("PPA") that would extend the PPA by 51 days from April 11, 2022 to May 31, 2022. The application to extend Palisades was filed in Case No. U-20734 and has yet to be approved by the Commission.

KEITH G. TROYER
May 29, 2020

EGI Contracts & Settlements

Question:

1. Refer to your responses to MEC-CE-528, 529, and 1008, and to the "MEC-CE-1008-ATT_1" spreadsheet.
a. Please confirm that when costs associated with the Classic 7 units are excluded from the depreciation reserve, the following are correct for Campbell units 1 and 2 (combined). If any of subparts (i)-(iv) are not confirmed, please identify the correct figures for each year, and produce any supporting workpapers.
i. End of year rate base in 2017, 2018, and 2019 is $750.3 million, $729.7 million, and $690.6 million, respectively.
ii. Post-tax rate of return in 2017, 2018, and 2019 is $45.6 million, $43.6 million, and $42.4 million, respectively.
iii. Income taxes in 2017, 2018, and 2019 is $20.4 million, $10.6 million, and $10.2 million, respectively.
iv. Depreciation expenses in 2017, 2018, and 2019 are $49,910,221, $51,120,241, and $52,033,363, respectively.
b. Please confirm that when costs associated with the Classic 7 units are excluded from the depreciation reserve, the following are correct for Campbell unit 3. If any of subparts (i)-(iv) are not confirmed, please identify the correct figures for each year, and produce any supporting workpapers.
i. End of year rate base in 2017, 2018, and 2019 is $1.065 billion, $1.01 billion, and $962 million, respectively.
ii. Post-tax rate of return in 2017, 2018, and 2019 is $64.8 million, $61.1 million, and $58.8 million, respectively.
iii. Income taxes in 2017, 2018, and 2019 is $29 million, $14.9 million, and $14.1 million, respectively.
iv. Depreciation expenses in 2017, 2018, and 2019 are $80,885,932, $81,885,944, and $83,732,514, respectively.
c. Please confirm that when costs associated with the Classic 7 units are excluded from the depreciation reserve, the following are correct for Karn units 1 and 2 (combined). If any of subparts (i)-(iv) are not confirmed, please identify the correct figures for each year, and produce any supporting workpapers.
i. End of year rate base in 2017, 2018, and 2019 is $951 million, $915.7 million, and $878.1 million, respectively.
ii. Post-tax rate of return in 2017, 2018, and 2019 is $58 million, $55 million, and $53.5 million, respectively.
iii. Income taxes in 2017, 2018, and 2019 is $17.2 million, $16.3 million, and $15.4 million, respectively.
iv. Depreciation expenses in 2017, 2018, and 2019 are $58,403,498, $58,851,638, and $59,113,578, respectively.

Response:

a.

i. Confirmed.

ii. Confirmed. Note that calculations for 2017 amounts utilize average rate base for 2017 and the 2016 rate base balances utilized do not exclude Classic 7 amounts.

iii. Confirmed. Note that calculations for 2017 amounts utilize average rate base for 2017 and the 2016 rate base balances utilized do not exclude Classic 7 amounts.

iv. Confirmed.

b.

i. Confirmed.

ii. Confirmed. Note that calculations for 2017 amounts utilize average rate base for 2017 and the 2016 rate base balances utilized do not exclude Classic 7 amounts.

iii. Confirmed. Note that calculations for 2017 amounts utilize average rate base for 2017 and the 2016 rate base balances utilized do not exclude Classic 7 amounts.

iv. Confirmed.

c.

i. Confirmed.

ii. Confirmed. Note that calculations for 2017 amounts utilize average rate base for 2017 and the 2016 rate base balances utilized do not exclude Classic 7 amounts.

iii. Not confirmed. Income taxes for Karn 1 & 2 for 2017, 2018, and 2019 are $25.9 million, $13.4 million, and $12.9 million. Note that calculations for 2017 amounts utilize average rate base for 2017 and the 2016 rate base balances utilized do not exclude Classic 7 amounts. Please see U20697-MEC-CE-1370-Hugo_ATT_1 for the supporting workpaper.

iv. Confirmed.

Scott A. Hugo
June 18, 2020

Director – Generation Asset Strategy

2015	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4
Beginning Rate Base	-	-	-	-
Ending Rate Base	-	-	-	-
Average Rate Base	-	-	-	-
Rate of Return Post Tax	-	-	-	-
Equity Return	-	-	-	-
Interest	-	-	-	-
Taxes	-	-	-	-

2016	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4
Beginning Rate Base	-	-	-	-
Ending Rate Base	798,788,668	1,134,630,110	1,018,180,061	89,125,980
Average Rate Base				
Rate of Return Post Tax	-	-	-	-
Equity Return	-	-	-	-
Interest	-	-	-	-
Taxes	-	-	-	-

2017	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4
Beginning Rate Base	798,788,668	1,134,630,110	1,018,180,061	89,125,980
Ending Rate Base	750,290,636	1,065,480,146	950,960,392	161,980,255
Average Rate Base	774,539,652	1,100,055,128	984,570,227	125,553,118
Rate of Return Post Tax	45,605,410	64,771,978	57,972,150	7,392,651
Equity Return	31,670,531	44,980,693	40,258,574	5,133,803
Interest	13,523,328	19,206,772	17,190,426	2,192,136
Taxes	20,395,676	28,967,359	25,926,336	3,306,145

2018	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4
Beginning Rate Base	750,290,636	1,065,480,146	950,960,392	161,980,255
Ending Rate Base	729,655,760	1,010,302,507	915,736,172	163,969,119
Average Rate Base	739,973,198	1,037,891,327	933,348,282	162,974,687
Rate of Return Post Tax	43,570,115	61,111,733	54,956,169	9,596,058
Equity Return	30,257,128	42,438,849	38,164,137	6,663,952
Interest	12,919,805	18,121,405	16,296,101	2,845,510
Taxes	10,617,136	14,891,665	13,391,681	2,338,361

2019	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4
Beginning Rate Base	729,655,760	1,010,302,507	915,736,172	163,969,119
Ending Rate Base	690,550,081	962,045,334	878,119,990	159,069,551
Average Rate Base	710,102,920	986,173,920	896,928,081	161,519,335
Rate of Return Post Tax	42,357,591	58,825,208	53,501,700	9,634,617
Equity Return	29,755,924	41,324,315	37,584,586	6,768,254
Interest	12,223,391	16,975,553	15,439,315	2,780,321
Taxes	10,186,810	14,147,197	12,866,918	2,317,082

2020	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4
Beginning Rate Base	690,550,081	962,045,334	878,119,990	159,069,551
Ending Rate Base	657,049,532	887,332,558	828,636,835	147,682,846
Average Rate Base	673,799,807	924,688,946	853,378,412	153,376,198
Rate of Return Post Tax	40,192,113	55,157,633	50,903,965	9,148,880
Equity Return	28,234,690	38,747,868	35,759,694	6,427,027
Interest	11,598,486	15,917,178	14,689,671	2,640,149
Taxes	9,666,022	13,265,162	12,242,174	2,200,264

2021	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4

Rate of Return - post-tax

	2015	2016	2017	2018	2019
Campbell 1 & 2	-	-	45,605,410	43,570,115	42,357,591
Campbell # 3	-	-	64,771,978	61,111,733	58,825,208
Karn 1 & 2	-	-	57,972,150	54,956,169	53,501,700
Karn 3 & 4	-	-	7,392,651	9,596,058	9,634,617

Equity Return

	2015	2016	2017	2018	2019
Campbell 1 & 2	-	-	31,670,531	30,257,128	29,755,924
Campbell 3	-	-	44,980,693	42,438,849	41,324,315
Karn 1 & 2	-	-	40,258,574	38,164,137	37,584,586
Karn 3 & 4	-	-	5,133,803	6,663,952	6,768,254

Interest Costs

	2015	2016	2017	2018	2019
Campbell 1 & 2	-	-	13,523,328	12,919,805	12,223,391
Campbell 3	-	-	19,206,772	18,121,405	16,975,553
Karn 1 & 2	-	-	17,190,426	16,296,101	15,439,315
Karn 3 & 4	-	-	2,192,136	2,845,510	2,780,321

Taxes

	2015	2016	2017	2018	2019
Campbell 1 & 2	-	-	20,395,676	10,617,136	10,186,810
Campbell 3	-	-	28,967,359	14,891,665	14,147,197
Karn 1 & 2	-	-	25,926,336	13,391,681	12,866,918
Karn 3 & 4	-	-	3,306,145	2,338,361	2,317,082

Rate of Return - Post-tax

	2020	2021
Campbell 1 & 2	40,192,113	39,187,034
Campbell 3	55,157,633	52,068,742
Karn 1 & 2	50,903,965	48,885,924
Karn 3 & 4	9,148,880	8,779,532

Equity Return

	2020	2021
Campbell 1 & 2	28,234,690	28,905,606
Campbell 3	38,747,868	38,407,565
Karn 1 & 2	35,759,694	36,059,817
Karn 3 & 4	6,427,027	6,476,063

Interest

	2020	2021
Campbell 1 & 2	11,598,486	9,951,670
Campbell 3	15,917,178	13,223,020
Karn 1 & 2	14,689,671	12,414,734
Karn 3 & 4	2,640,149	2,229,590

Taxes

	2020	2021
Campbell 1 & 2	9,666,022	9,888,862
Campbell 3	13,265,162	13,139,566
Karn 1 & 2	12,242,174	12,336,380
Karn 3 & 4	2,200,264	2,215,518

Depreciation Expense

	2020	2021
Campbell 1 & 2	52,404,010	53,131,911

Campbell 3	85,079,577	85,453,495
Karn 1 & 2	59,420,335	59,584,737
Karn 3 & 4	18,131,706	18,518,703

Beginning Rate Base	657,049,532	Beginning Rate Base	887,332,558	Beginning Rate Base	828,636,835	Beginning Rate Base	147,682,846
Ending Rate Base	629,357,960	Ending Rate Base	821,947,621	Ending Rate Base	776,159,768	Ending Rate Base	140,526,143
Average Rate Base	643,203,746	Average Rate Base	854,640,090	Average Rate Base	802,398,301	Average Rate Base	144,104,494
Rate of Return Post Tax	39,187,034	Rate of Return Post Tax	52,068,742	Rate of Return Post Tax	48,885,924	Rate of Return Post Tax	8,779,532
Equity Return	28,905,606	Equity Return	38,407,565	Equity Return	36,059,817	Equity Return	6,476,063
Interest	9,951,670	Interest	13,223,020	Interest	12,414,734	Interest	2,229,590
Taxes	9,888,862	Taxes	13,139,566	Taxes	12,336,380	Taxes	2,215,518

Consumers Energy
Generation Balances by Site

As of 12/31/2014

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve	RB
Campbell 1 & 2						-
Campbell # 3						-
Karn 1 & 2						-
Karn 3 & 4						-
Total Steam Generation	-	-	-	-	-	

As of 12/31/2015

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve	RB
Campbell 1 & 2						-
Campbell # 3						-
Karn 1 & 2						-
Karn 3 & 4						-
Total Steam Generation	-	-	-	-	-	

As of 12/31/2016

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve	RB
Campbell 1 & 2	7,062,772	1,003,238,051	1,159,863	1,004,397,914	212,672,019	798,788,668
Campbell # 3	12,933,389	1,645,922,133	1,730,079	1,647,652,212	525,955,490	1,134,630,110
Karn 1 & 2	11,041,971	1,176,497,300	178,947	1,176,676,246	169,538,156	1,018,180,061
Karn 3 & 4	7,708,170	323,145,824	50,886	323,196,710	241,778,899	89,125,980
Total Steam Generation	38,746,301	4,148,803,308	3,119,774	4,151,923,082	1,149,944,564	

These amounts have not been adjusted to remove Classic 7 amounts from accumulated depreciation.

As of 12/31/2017

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve	RB
Campbell 1 & 2	21,729,172	1,016,982,840	1,159,863	1,018,142,703	289,581,239	750,290,636
Campbell # 3	30,242,585	1,652,697,243	1,730,079	1,654,427,322	619,189,760	1,065,480,146
Karn 1 & 2	16,420,567	1,170,444,816	178,947	1,170,623,763	236,083,937	950,960,392
Karn 3 & 4	2,718,327	341,682,199	50,886	341,733,085	182,471,157	161,980,255
Total Steam Generation	71,110,650	4,181,807,098	3,119,774	4,184,926,872	1,327,326,093	

As of 12/31/2018

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve	RB
Campbell 1 & 2	9,806,590	1,051,212,380	1,159,863	1,052,372,243	332,523,074	729,655,760
Campbell # 3	23,772,840	1,685,970,544	1,730,079	1,687,700,622	701,170,956	1,010,302,507
Karn 1 & 2	8,693,293	1,183,122,159	178,947	1,183,301,105	276,258,226	915,736,172
Karn 3 & 4	12,716,262	348,009,195	50,886	348,060,081	196,807,224	163,969,119

Total Steam Generation	54,988,986	4,268,314,277	3,119,774	4,271,434,052	1,506,759,480

As of 12/31/2019

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve	
Campbell 1 & 2	14,455,737	1,053,311,870	1,159,863	1,054,471,733	378,377,389	690,550,081
Campbell # 3	15,970,464	1,728,866,203	1,730,079	1,730,596,282	784,521,412	962,045,334
Karn 1 & 2	7,677,542	1,191,207,867	178,947	1,191,386,813	320,944,365	878,119,990
Karn 3 & 4	9,429,195	363,956,295	50,886	364,007,181	214,366,824	159,069,551
Total Steam Generation	47,532,938	4,337,342,234	3,119,774	4,340,462,009	1,698,209,990	

As of 12/31/2020 (Projected)

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve		2020: Reserve Excluding Classics	2020: Classics Reserve Allocated	2020: Depreciation Reserve
Campbell 1 & 2	11,843,743	1,068,307,958	1,159,863	1,069,467,822	424,262,032	657,049,532	424,262,032	(34,491,477)	389,770,555
Campbell # 3	6,717,288	1,739,593,282	1,730,079	1,741,323,360	860,708,090	887,332,558	860,708,090	(69,973,486)	790,734,605
Karn 1 & 2	4,262,808	1,195,103,071	178,947	1,195,282,018	370,907,991	828,636,835	370,907,991	(30,153,922)	340,754,069
Karn 3 & 4	4,332,195	373,689,660	50,886	373,740,546	230,389,895	147,682,846	230,389,895	(18,730,141)	211,659,754
	27,156,034	4,376,693,971	3,119,774	4,379,813,745	1,886,268,009		1,886,268,009	(153,349,026)	1,732,918,983

As of 12/31/2021 (Projected)

Description	Construction Work in Progress	Plant in Service: Plant in Service	Plant in Service: Land	Plant in Service: Gross Plant Investment	Depreciation Reserve		2021: Reserve Excluding Classics	2021: Classics Reserve Allocated	2021: Depreciation Reserve
Campbell 1 & 2	16,331,645	1,082,781,566	1,159,863	1,083,941,429	470,915,114	629,357,960	470,915,114	(38,284,260)	432,630,855
Campbell # 3	13,138,051	1,744,109,797	1,730,079	1,745,839,876	937,030,305	821,947,621	937,030,305	(76,178,297)	860,852,008
Karn 1 & 2	892,377	1,197,810,189	178,947	1,197,989,136	422,721,745	776,159,768	422,721,745	(34,366,255)	388,355,490
Karn 3 & 4	7,283,195	379,700,331	50,886	379,751,217	246,508,269	140,526,143	246,508,269	(20,040,526)	226,467,743
Total Steam Generation	37,645,268	4,404,401,883	3,119,774	4,407,521,658	2,077,175,434		2,077,175,434	(153,349,026)	1,908,306,096

	Actual					CE Projection				
Fixed O&M	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Campbell 1	$10,740,799	$10,762,757	$9,763,440	$9,585,839	$10,323,714	$13,532,338	$12,457,386	$12,134,877	$11,823,749	$13,084,841
Campbell 2	$11,481,244	$11,928,112	$10,626,153	$13,645,866	$12,519,703	$10,226,237	$19,137,633	$12,073,127	$12,115,827	$12,231,247
Source	*CE-548 ATT 1*	*CE-548 ATT 1*	*CE-548 ATT 1*	*CE-1022 ATT 1*	*CE-1022 ATT 1*	*CE-1022 ATT 2*	*CE-1022 ATT 2*	*CE-548 ATT 1*	*CE-548 ATT 1*	*CE-548 ATT 1*

Note: includes base O&M, major maintenance, and environmental O&M

Question:

8. Refer to the "U20697-MEC-CE-035-Hugo_ATT_1" spreadsheet.

a. Please identify which capital projects listed will be "expensed" or recovered in the year spent.

b. Please identify which capital projects will be financed over a period of longer than a year.

i. For these projects, please provide annual revenue requirements including a breakdown of depreciation, rate of return, and taxes.

Response:

a. Referring to the environmental capital projects and non-environmental capital projects for the Campbell and Karn sites listed on Attachment U20697-MEC-CE-035_ATT_1, none of these capital expenditures will be expensed in 2020 or 2021.

b. All of the capital expenditures for the environmental capital projects and non-environmental capital projects at the Campbell site will be "financed" over the depreciable life of each of the assets. The Company has not calculated annual revenue requirements for each of the projects. All of the capital expenditures for the environmental capital projects and non-environmental capital projects at the Karn site whose expenditures are allocated to Karn Units 1 and 2 will be "financed" over the depreciable life of each of the assets or until which time the MPSC issues an order which approves the securitization of these expenditures and securitization bonds are issued for their recovery.

Scott A. Hugo
May 1, 2020

Director – Generation Asset Strategy

Capacity factor	actual					CE 2020 projection				
Actual and CE 2020 projection	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**			
Campbell 1	67%	53%	43%	51%	64%	58%	59%			
Campbell 2	53%	52%	38%	44%	54%	52%	46%			

Availability	actual					CE 2020 projection				
Actual and CE 2020 projection	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Campbell 1	82%	77%	71%	78%	74%	60%	64%	67%	73%	66%
Campbell 2	75%	70%	61%	71%	63%	55%	50%	68%	68%	73%

Periodic factor	actual					CE 2020 projection				
Actual and CE 2020 projection	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Campbell 1	8%	11%	14%	14%	14%	23%	17%	12%	2%	11%
Campbell 2	22%	23%	12%	21%	18%	30%	36%	12%	11%	3%

Random outage rate	actual					CE 2020 projection				
Actual and CE 2020 projection	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Campbell 1	11%	14%	18%	10%	14%	22%	23%	24%	25%	26%
Campbell 2	3%	9%	30%	11%	23%	21%	22%	23%	24%	25%
Source	*CE-1022 ATT 1*	*CE-1022 ATT 1*	*CE-1022 ATT 1*	*CE-1022 ATT 1*	*CE-1022 ATT 1*	*CE-1022 ATT 2*	*CE-1022 ATT 2*	*CE-548 ATT 1*	*CE-548 ATT 1*	*CE-548 ATT 1*

Random outage rate	2018	2019	2020	2021	2022	2023	2024
CE 2018 IRP projection							
Campbell 1	10.00%	10.50%	11.00%	11.50%	12.00%	12.00%	12.50%
Campbell 2	7.00%	7.50%	8.00%	8.50%	9.00%	9.00%	9.50%

Random outage rate	2025	2026	2027	2028	2029	2030	2031
CE 2018 IRP projection							
Campbell 1	13.00%	13.50%	13.50%	14.00%	14.50%	15.00%	15.00%
Campbell 2	10.00%	10.50%	10.50%	11.00%	11.50%	12.00%	12.00%

Source: U-20165-November 20, 2018 Official Exhibits MEC-NRDC-SC, Exhibit MEC-60 (20165-MEC-CE-18 +ROR 2018 IRP)

Question:

13. Refer to page 100, line 14 through page 107, line 5 of the Hugo Direct Testimony and Exhibit SAH-4.

a. For each of the 2024 and 2025 Campbell Units 1 and/or 2 retirement scenarios identified in Exhibit SAH-4:
i. Please identify each specific project and its cost that is included in the Unavoidable capital expenditures (both environmental and nonenvironmental), and provide the following information:
a) Please explain what steps you took to evaluate whether each such project would be avoidable in a 2024 or 2025 retirement scenario.
b) Please explain why each such expenditure is purportedly unavoidable in a 2024 or 2025 retirement scenario.
c) Please produce all analyses, reports, and other documents regarding whether a particular project is avoidable or the evaluation of the same.
ii. Please identify each specific project and its cost that is included in the Incremental capital expenditures, and provide the following information:
a) Please explain what steps you took to evaluate whether each such project would be incremental in a 2024 or 2025 retirement scenario.
b) Please explain why each such expenditure is purportedly incremental in a 2024 or 2025 retirement scenario.
c) Please produce all analyses, reports, and other documents regarding whether a particular project is incremental or the evaluation of the same.
b. For each of the 2024 and 2025 Campbell Units 1 and/or 2 retirement scenarios identified in Exhibit SAH-4, please provide the Company's most up-to-date projection for each of the years 2022-2025 of:
i. avoidable capital expenditures at Campbell Units 1-3;
ii. unavoidable capital expenditures at Campbell Units 1-3;
iii. incremental capital expenditures at Campbell Units 1-3.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the basis that it is unduly burdensome to the extent that it seeks "all" analyses, reports, and other documents relating to whether a particular project is incremental. Additionally, this request seeks information that is beyond the scope of the Compnay's request for relief in this proceeding. Without waiving these objections, the Company responds as follows:

a.

i.Please refer to Scott Hugo WP-SAH-22 attached as U20697-MEC-CE-44_ATT1. This attachment includes all projected 2021 Campbell capital expenditures. The Avoidable capital expenditures are highlighted in green. The balance of the capital projects were deemed Unavoidable.

a) Projects are evaluated and approved based on three basic criteria:

1. Safety, Compliance and Regulatory. This work scope is carefully reviewed to ensure the most cost-effective compliance strategy is achieved. This strategy reduces the amount of capital investment necessary for compliance in the short term (2 to 3 years).

2. Equipment condition. Some projects are necessary to repair broken or degraded equipment that is essential to operation. This work scope is necessary to maintain the functionality of the generating plants.
3. Economic projects that impact heat rate, capacity and/or reliability. Additional scrutiny has been placed on these projects to ensure that they result in an overall reduction in the costs of producing energy for our customers.

Projects needed to maintain functionality and reliability of critical equipment, to address equipment known to be in a degraded condition, and to maintain compliance with regulatory/environmental requirements were identified as unavoidable. Economic projects were reevaluated based on the retirement date scenario, and a project was identified as avoidable if the project did not offer continued economic customer benefits.

b) Please see sub-part (a) i.

c) Please see sub-part (a) i.a.

ii. Please refer to Scott Hugo WP-SAH-23 attached as U20697-MEC-CE-44_ATT2.

a) Projects which fell into either of the two following categories were deemed Incremental capital expenditures:

1. Separation. Projects required to effectively separate the operation of Campbell Units 1 and 2 from the operation of Campbell Unit 3. This work scope will allow Campbell Unit 3 to operate independently after the theoretical retirement of Campbell Units 1 and 2.
2. Decommissioning. Projects required to effectively decommission Campbell Units 1 and 2 following their theoretical retirement. The decommissioning work scope includes cessation of operations, removal of energy sources ("Cold & Dark"), utility isolation, environmental abatement, demolition, and site restoration.

b) Please see sub-part (a) ii.a. The identified Separation and Decommissioning projects were deemed Incremental capital expenditures in a theoretical 2024 or 2025 retirement scenario based on the required timeline to execute an effective decommissioning project.

c) Please see sub-part (a) ii.

b. Consumers Energy has not evaluated projects beyond 2021.

Scott A. Hugo
April 6, 2020

Director – Generation Asset Strategy

Question:

14. Refer to page 132, line 8 through page 137, line 10 of the Hugo Direct Testimony and Exhibit SAH-4.

a. For each of the 2024 and 2025 Campbell Units 1 and/or 2 retirement scenarios identified in Exhibit SAH-6:
i. Please identify each specific project and its cost that is included in the Unavoidable major maintenance expenses (both environmental and nonenvironmental), and provide the following information:
a) Please explain what steps you took to evaluate whether each such project would be avoidable in a 2024 or 2025 retirement scenario.
b) Please explain why each such major maintenance expense is purportedly unavoidable in a 2024 or 2025 retirement scenario.
c) Please produce all analyses, reports, and other documents regarding whether a particular project is avoidable or the evaluation of the same.
b. For each of the 2024 and 2025 Campbell Units 1 and/or 2 retirement scenarios identified in Exhibit SAH-6, please provide the Company's most up-to-date projection for each of the years 2022-25 of:
ii. avoidable major maintenance expenses at Campbell Units 1-3;
iii. unavoidable major maintenance expenses at Campbell Units 1-3;
iv. incremental major maintenance expenses (if any) at Campbell Units 1-3.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the basis that it is unduly burdensome to the extent that it seeks "all" analyses, reports, and other documents relating to whether a particular project is avoidable. Additionally, this request seeks information that is beyond the scope of the Company's request for relief in this proceeding. Without waiving these objections, the Company responds as follows:

a.

i. Please refer to Scott Hugo WP-SAH-21 attached as U20697-MEC-CE-45_ATT1. This attachment includes all projected 2021 Campbell major maintenance expenses. The major maintenance expenses are highlighted in green. The balance of the major maintenance projects were deemed Unavoidable.

a) Projects are evaluated and approved based on three basic criteria:

1. Safety, Compliance and Regulatory. This work scope is carefully reviewed to ensure the most cost-effective compliance strategy is achieved. This strategy reduces the amount of major maintenance expense necessary for compliance in the short term (2 to 3 years).
2. Equipment condition. Some projects are necessary to repair broken or degraded equipment that is essential to operation. This work scope is necessary to maintain the functionality of the generating plants.
3. Economic projects that impact heat rate, capacity and/or reliability. Additional scrutiny has been placed on these projects to ensure that they result in an overall reduction in the costs of producing energy for our customers.

Projects needed to maintain functionality and reliability of critical equipment, to address equipment known to be in a degraded condition, and to maintain compliance with regulatory/environmental requirements were identified as unavoidable. Economic projects were reevaluated based on the retirement date scenario, and a project was identified as avoidable if the project did not offer continued economic customer benefits.

b) Please see sub-part (a) i.

c) Please see sub-part (a) i.a.

b. Consumers Energy has not evaluated major maintenance projects beyond 2021.

Scott A. Hugo
April 6, 2020

Director – Generation Asset Strategy

Question:

7. Refer to the “MEC-CE-044_ATT_1” and “MEC-CE-035_ATT_12 Revised” spreadsheets.
a. MEC-CE-035_ATT_12 Revised identifies IRRs for five capital projects at Campbell planned for 2021 (project nos. 5586, 5462, 9950, 5747, and 8639). Has the Company performed an IRR or PVR for any other capital project (regardless of its estimated cost) planned for 2021? If yes:
i. Please identify all other capital projects planned for 2021 that have an IRR or PVR, and for each such project:
a) MEC-CE-035_ATT_12 Revised identifies IRRs for five capital projects at Campbell planned for 2021 (project nos. 5586, 5462, 9950, 5747, and 8639). Has the Company performed an IRR or PVR for any other capital project (regardless of its estimated cost) planned for 2021? If yes:
i. Please identify all other capital projects planned for 2021 that have an IRR or PVR, and for each such project:
a) Please identify the IRR and/or PVR, and produce in machine-readable electronic format with formulas intact, all workpapers created, used, or
relied on in calculating such IRR and PVR.
b) Please produce the project charter, project scope document, and/or other written evaluation of the costs and benefits of each identified project.
b. Please provide any IRR or PVR analysis associated with the following capital projects: project nos. 5537, 5577, 5589, 5573. Please also provide any supporting workpapers.
c. Further refer to your response to MEC-CE-44(a)(i)(a), which states that capital projects are evaluated and approved based on three basic criteria (safety/compliance/regulatory, equipment condition, and economic), and that only economic projects were reevaluated for avoidability. Please supplement the “MEC-CE-044_ATT_1” spreadsheet with the following information:
i. Please identify the Approval Criteria for each of the listed projects;
ii. Please identify the projects listed on this spreadsheet that were “reevaluated based on the retirement date scenario,” to determine if they were avoidable under a 2024 or 2025 retirement.

Response:

a. No. The Company has not yet performed an IRR or PVR calculation for any other capital project planned for 2021. However, as identified on U20697-MEC-CE-035_ATT_12 Revised, there are three projects which are current in the engineering phase (Work IDs 5589, 5707 & 5708) for which the Company will perform an economic analysis upon completion of the engineering.

b. IRR or PVR analyses have not been performed for projects with work IDs of 5537, 5577, 5589 and 5573. However, as discussed in the response to subpart (a), the engineering for the project with work ID 5589 is in progress and an economic analysis will be performed upon completion of the engineering.

c. Please refer to attachment U20697-MEC-CE-1014_ATT_1 for an update to Attachment U20697-MEC-CE-545_ATT_1. The update includes an additional column specifying the Approval Criteria category for each capital project. There were no economic projects for Campbell Units 1 and/or 2 which were re-evaluated based on the early retirement scenarios. The projects which were deemed avoidable were primarily related to equipment condition. In the case of an early retirement, CE would take on additional equipment reliability risk with the elimination of these projects and forego the specified equipment replacements and overhauls within a few years of retirement. There are also some avoidable projects related to compliance. In this case, CE would forego a SCR Catalyst Layer Replacement and/or Pulse Jet Fabric Filter Bag Replacement within a year of unit retirement and risk unit derates if unable to maintain compliance under full load operation. The final Distributed Control System Replacements for both Campbell Units 1 and 2 are also listed as avoidable. CE has internal compliance requirements to maintain software updates and patching capability for unit control systems, so DCS Replacements typically occur on a five-year cycle. Avoiding these final DCS Replacements would push that interval to approximately 6 years.

Scott A. Hugo
May 29, 2020

Director – Generation Asset Strategy

Recommended Disallowances

Capital Spending at Campbell Units 1 and 2 that Consumers has Identified as Avoidable with 2024 Retirement[1]

Unit	Work ID	2021 spending
Campbell 1	5589 -JHC1 SH Outlet Pendant - partial replacement	$200,000
Campbell 2	5537 -JHC2 Replace Burner Assemblies -6	$550,000
Campbell 2	5573 -JHC2 Overhaul CCWP & Motors	$580,000
Campbell 2	5577 -JHC2 - Overhaul JHC2 FD Fan Motors	$402,000
TOTAL		**$1,732,000**

Major Maintenance Spending at Campbell Units 1 and 2 that Consumers has Identified as Avoidable with 2024 Retirement[2]

Unit	Work ID	2021 spending
Campbell 1	5628 -JHC1 Install Voting Sudden Pressure Relay System on GSU and SPTs 1A and 1B	$62,000
Campbell 2	5598 -JHC2 Motor Maintenance	$100,000
Campbell 2	5601 -JHC2 Pump Maintenance	$100,000
Campbell 2	5602 -JHC2 Coal Bunker Maintenance	$75,000
Campbell 2	5659 -JHC2 Transformer Base Maintenance	$175,000
Campbell 1&2	5596 -JHC1-2 Breaker Maintenance	$100,000
Campbell 1&2	5597 -JHC1&2 Medium Voltage Breaker Inspection & Cleaning	$60,000
TOTAL		**$672,000**

Additional Capital Spending at Campbell Units 1 and 2 that is Avoidable with 2024 Retirement[3]

Unit	Work ID	2021 spending
Campbell 2	5462 - JHC2 SAH Replace baskets and seals	$2,425,000
Campbell 2	9950 - JHC2 LP Turbine Component Replacement[4]	$3,300,000
TOTAL		**$5,725,000**

[1] MEC-CE-545-Hugo_ATT_1, rows 18, 38, 40, and 96.
[2] MEC-CE-544 Att 1, rows 34-38, 40, and 44.
[3] MEC-CE-545-Hugo_ATT_1, rows 12 and 127.
[4] For project 9950, see discussion on pages 38-39 of my testimony.

Capital Projects Above $100,000 That Have Inadequate or No Supporting Documentation[5]

Unit	Work ID	2021 spending	Reason *(Source)*
Campbell 1	5543 -JHC1 Mill Overhauls (grinding section & gearbox)	$696,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 1	8616 -JHC 1 Re-align 4160V switchgear with AQCS implementation	$1,000,000	See discussion on pages 43-44 of my testimony.
Campbell 1	9650 -JHC1 Major Motor and Pump Overhauls	$200,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 1	9653 -JHC1 Balance of Plant Equipment Replacements	$150,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 1	9655 -JHC1 AQCS Projects	$250,000	No supporting docs *(MEC-CE-1017(b); MEC-CE-35 ATT 12 2nd Revised)*
Campbell 2	5545 -JHC2 Overhaul Hydraulic Coupling Rotor	$459,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 2	3089 -JHC2 Mill Overhauls (grinding section & gearbox) (H2017 // MC)	$400,000	No supporting docs *(MEC-CE-1017(b); MEC-CE-35 ATT 122nd Revised)*
Campbell 2	5594 -JHC2 Main BFP overhaul	$359,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 2	5663 -JHC 2 2A Condensate Pump Overhaul	$210,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 2	9651 -JHC2 Major Motor and Pump Overhauls	$200,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 2	9654 -JHC2 Balance of Plant Equipment Replacements	$150,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 2	9656 -JHC2 AQCS Projects	$250,000	No supporting docs *(MEC-CE-1017(b); MEC-CE-35 ATT 12 2nd Revised)*
Campbell 3	5689 -JHC3 Install Boiler Slag Reducing Coating Front and Rear Walls	$53,000*	No supporting docs *(MEC-CE-1017(a))*
Campbell 3	5691 -JHC 3 Replace CO-O2 monitors	$1,044,600	No supporting docs *(MEC-CE-1017(a))*
Campbell 3	5693 -JHC3 Mill Complete Overhauls	$1,235,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 3	5707 -JHC3 Reheater Sootblower	$1,250,000	No supporting docs *(MEC-CE-1017(a))*; intends to perform economic analysis in the future *(MEC-CE-1014(a))*

[5] See generally MEC-CE-545-Hugo_ATT_1.

Campbell 3	5708 -JHC3 Redundant Sootblowing Air Compressor	$1,200,000	Minimal supporting documentation *(MEC-CE-035_ATT_47)*; intends to perform economic analysis in the future *(MEC-CE-1014(a))*
Campbell 3	5746 -JHC3 Install Online Dissolved Gas Analysis on GSUs	$189,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 3	9690 -JHC3 Balance of Plant Equipment Replacements	$200,000	No supporting docs *(MEC-CE-1017(a))*
Campbell 3	9692 -JHC3 AQCS Projects	$250,000	No supporting docs *(MEC-CE-1017(b); MEC-CE-35 ATT 12 2nd Revised))*
Campbell Commons	5480 -JHC FH Replace Fuel Handling Conveyor Belts - JHCAll201508101343	$427,000	No supporting docs *(MEC-CE-1017(a))*
Campbell Commons	9671 -JHC Fuel Handling/Infrastructure Replacements	$500,000	No supporting docs *(MEC-CE-1017(a))*
TOTAL		**$10,672,600**	

*2021 spending is under $100,000 but subsequent year's spending is substantially above $100,000

Major Maintenance Projects Above $100,000 That Do Not Have Supporting Documentation[6]

Unit	Work ID	2021 spending	Reason *(Source)*
Campbell Common	5516 -JHC Landfill - Clean Dry Ash Silos	$141,000	No supporting docs *(MEC-CE-1018)*
Campbell 2	5632 -JHC Unit 2 Screenhouse and Tunnel Cleaning	$225,000	No supporting docs *(MEC-CE-1018)*
TOTAL		**$366,000**	

[6] MEC-CE-544 ATT 1, rows 15 and 42.

Question:

17. Refer to the WP-SAH-21 workpaper and Exhibit A-71 (SAH-6). Using the pivot table, one can view projects for 2020 through 2024.

a. Can any of the projects shown in 2022, 2023, or 2024 be avoided if Campbell 1 and/or 2 retire in 2024?

i. If so, please identify each such project, its associated cost, and the year(s) in which such costs would be avoided.

ii. If not, please provide supporting documentation and/or analyses for why such costs are unavoidable.

iii. If Consumers has not performed such an analysis, please explain why not.

b. Can any of the projects shown in 2022, 2023, or 2024 be avoided if Campbell 1 and/or 2 retire in 2025?

i. If so, please identify each such project, its associated costs, and the year(s) in which such costs would be avoided.

ii. If not, please provide supporting documentation and/or analyses for why such costs are unavoidable.

iii. If Consumers has not done such an analysis, please explain why not.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request to the extent that it requests information that is not relevant to this proceeding. Specifically, it requests information beyond the 2021 test year, for which the Company is not requesting recovery in rates in this case. Without waiving this objection, the Company responds as follows:

a. Yes. Additional major maintenance projects which are projected for the years 2022, 2023, and 2024 have now been highlighted in Attachment U20697-MEC-CE-544_ATT_1 if the expense could be avoided with a 2024 retirement. All green and orange highlighted projects can be avoided with a 2024 retirement of Campbell 1 and/or 2. Note that the totals shown on Attachment U20697-MEC-CE-544_ATT_1 still reflect the 2021 test year only.

b. Yes. Additional major maintenance projects which are projected for the years 2022, 2023, and 2024 have now been highlighted in in Attachment U20697-MEC-CE-544_ATT_1 if the expense can be avoided with a 2025 retirement. Only the green highlighted items can be avoided with a 2025 retirement of Campbell 1 and/or 2. Note that the totals shown on Attachment U20697-MEC-CE-544_ATT_1 still reflect the 2021 test year only.

Scott A. Hugo
May 1, 2020

Director – Generation Asset Strategy

Question:

18. Refer to the WP-SAH-22 workpaper and Exhibit A-69 (SAH-4). Using the pivot table, one can view projects for 2020 through 2024.
a. Can any of the projects shown in 2022, 2023, or 2024 be avoided if Campbell 1 and/or 2 retire in 2024?
i. If so, please identify each such project, its associated cost, and the year(s) in which such costs would be avoided.
ii. If not, please provide supporting documentation and/or analyses for why such costs are unavoidable.
iii. If Consumers has not performed such an analysis, please explain why not.
b. Can any of the projects shown in 2022, 2023, or 2024 be avoided if Campbell 1 and/or 2 retire in 2025?
i. If so, please identify each such project, its associated costs, and the year(s) in which such costs would be avoided.
ii. If not, please provide supporting documentation and/or analyses for why such costs are unavoidable.
iii. If Consumers has not done such an analysis, please explain why not.
c. Please explain why "5577 -JHC2 - Overhaul JHC2 FD Fan Motors" in WP-SAH-22 is designated as unavoidable with 2024 retirement but not with 2025 retirement.
i. Please provide supporting documentation and/or analyses supporting this designation.
d. Please explain why "5573 -JHC 2 Overhaul CCWP & Motors" in WP-SAH-22 is designated as unavoidable with 2024 retirement but not with 2025 retirement.
i. Please provide supporting documentation and/or analyses supporting this designation.
e. Please confirm that the WP-SAH-22 workpaper contains the following errors. If not confirmed, please explain why.
i. Cell N37 incorrectly subtracts "non-env" costs from Campbell 1, instead of "env" costs.
ii. Cell O37 incorrectly subtracts "env" costs from Campbell 1, instead of "non-env" costs.
iii. Cell N45 has "2024 retirement" but should be "2025 retirement."
f. If any of the errors identified above in subpart (e) are confirmed, please provide an updated version of the WP-SAH-22 workpaper that fixes the confirmed errors and an updated version of associated exhibits that are affected, such as A-69(SAH-4).

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request to the extent that it requests information that is not relevant to this proceeding. Specifically, it requests information beyond the 2021 test year, for which the Company is not requesting recovery in rates in this case. Without waiving this objection, the Company responds as follows:

a. Yes. Additional capital projects which are projected for the years 2022, 2023, and 2024 have now been highlighted in Attachment U20697-MEC-CE-545_1 if the expenditure could be avoided with a 2024 retirement. All green and orange highlighted items can be avoided with a 2024 retirement of Campbell 1 and/or 2. Note that the totals shown on Attachment U20697-MEC-CE-545_1 still reflect the 2021 test year only.

b. Yes. Additional capital projects which are projected for the years 2022, 2023, and 2024 have now been highlighted in Attachment U20697-MEC-CE-545_1 if the expenditure could be avoided with a 2025 retirement. All green highlighted items can be avoided with a 2025 retirement of Campbell 1 and/or 2. Note that the totals shown on Attachment U20697-MEC-CE-545_1 still reflect the 2021 test year only.

c. Clarification: "5577 -JHC2 - Overhaul JHC2 FD Fan Motors" in WP-SAH- 22 is designated *avoidable* with a 2024 retirement scenario but not with a 2025 retirement scenario. This is based on an assumption that no major components would be planned for overhaul or replacement within 3.5 years of the retirement date. (After 12/31/2020 for a 2024 retirement scenario and after 12/31/2021 for a 2025 retirement scenario).

   I. Customers would not receive the full benefits of replacing major equipment and/or restoring major equipment to like-new condition less than 4 years from unit retirement. Equipment replacements and/or overhauls are only considered on an emergent basis in the case of a failure or impending failure on units within the fleet which are less than 4 years from retirement. This methodology is consistent with the approach that the Company has taken for Karn Units 1 & 2 over the past 10+ months as those units approach their May 31, 2023 retirement.

d. Clarification: "5573 -JHC 2 Overhaul CCWP & Motors" in WP-SAH- 22 is designated *avoidable* with a 2024 retirement scenario but not with a 2025 retirement scenario. This is based on an assumption that no major components would be planned for overhaul or replacement within 3.5 years of the retirement date. (After 12/31/2020 for a 2024 retirement scenario and after 12/31/2021 for a 2025 retirement scenario)

I. Customers would not receive the full benefits of replacing major equipment and/or restoring major equipment to like-new condition less than 4 years from unit retirement. Equipment replacements and/or overhauls are only considered on an emergent basis in the case of a failure or impending failure on units within the fleet which are less than 4 years from retirement. This methodology is consistent with the approach that the Company has taken for Karn Units 1 & 2 over the past 10+ months as those units approach their May 31, 2023 retirement.

e. The underlying calculations were correct however the labels (Env vs. Non-Env) for row 37 were incorrect as they didn't align with the labels for all other rows. The label in row 45 was incorrect as well.

f. See Attachment U20697-MEC-CE-545_ATT_2. The changes are in bold, italicized red font.

Scott A Hugo

Scott A. Hugo
May 1, 2020

Director – Generation Asset Strategy

Avoidable with 2024 or 2025 retirement *(per MEC-CE-545(b))*
Avoidable with 2024 retirement only *(per MEC-CE-545(a))*

Sources												
MEC-CE-545 Att 1						*MEC-CE-1014 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1017*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
		Year										
WorkItemName with ID	**Work ID**	**2021**	**2022**	**2023**	**2024**	**Approval Criteria**	**Unavoidable but Deferable in 2021 (per CE)?**	**Attachment**	**Objective**	**IRR (if available)**	**Problem Statement**	**Scope**
5453 -JHC 1&2 SEEG - Waste Water Treatment	5453	$ 882,622	$ 4,949,135	$ 5,695,965		Safety/Compliance/ Regulatory	N	See Heather Breining Testimony				
5456 -JH Campbell 3 SEEG - Waste Water Treatment	5456	$ 1,206,000	$ 6,760,000	$ 7,780,000		Safety/Compliance/ Regulatory	N	See Heather Breining Testimony				
5459 -JHC FH Dust Collector Bag Replacement	5459	$ 130,000	$ 130,000	$ 130,000	$ 130,000	Safety/Compliance/ Regulatory	Y	MEC-CE-1017-Hugo_ATT_1				
5462 -JHC2 SAH Replace baskets and seals	5462	$ 2,425,000	$ -	$ -		Economic & Equipment Condition	Y			U20697-MEC-CE-035_ATT_4 Confidential		Remove and replace the hot and cold end baskets and seals and replace the axial seals. Set seal clearances and inspect and repair any rotor damage with baskets removed.
5476 -JHC Site Campbell UBAS Upgrades	5476	$ 250,000	$ 250,000	$ 250,000	$ 250,000	Safety/Compliance/ Regulatory	Y	U20697-MEC-CE-035_ATT_48	See Attached		JH Campbell Fuel Handling also has 2 dust collectors located on the south side of the Transfer House that are in need of bag replacement in 2020. The current bags have reached their expected life and keep the dust collectors functioning efficiently, they will need to be replaced. These dust collectors capture dust from the entire Transfer House while fueling the plants and is the building housing many of the main conveyors and components used to fuel Units 1,2&3.	
5501 -JHC Site Part 115 B-K landifll cap	5501	$ -	$ -	$ -	$ 21,000	Safety/Compliance/ Regulatory	N/A - no spending in 2021					
5522 -JHC 1&2 SEEG - Compliance - Closed Loop W/ Recirc.	5522	$ 2,118,293	$ 4,714,142	$ 5,173,835		Safety/Compliance/ Regulatory	N	See Heather Breining Testimony			Dust collectors are the first line of defense against against coal dust piling up and creating a significant opportunity for a fire. When these bags are plugged and non-functional, our risk increases dramatically.	
5523 -JH Campbell 3 SEEG - Compliance - Closed Loop W/ Recirc.	5523	$ 2,893,000	$ 6,439,000	$ 7,067,000		Safety/Compliance/ Regulatory	N	See Heather Breining Testimony				
5537 -JHC 2 Replace Burner Assemblies -6	5537	$ 550,000	$ 1,325,000	$ -		Equipment Condition	N/A - CE has identified as avoidable				Replace six degraded burner assemblies to meet MATS requirements and to avoid forced outage due to burner malfunction/windbox fires.	
5538 -JHC 1&2 - 316B Deep Water Intake	5538	$ 500,000	$ 12,000,000	$ 29,489,000		Safety/Compliance/ Regulatory	N	See Heather Breining Testimony				
5562 -JHC2 Catalyst Management	5562	$ 1,500,000	$ 1,120,000	$ 1,800,000	$ -	Safety/Compliance/ Regulatory	N	U20697-MEC-CE-035_ATT_16	See Attached			
5566 -JHC 2 PJFF bag replacement	5566	$ 2,694,000	$ -	$ -	$ -	Safety/Compliance/ Regulatory	N	U20697-MEC-CE-035_ATT_45	See Attached			
5670 -JHC3 SCR Catalyst Management	5670	$ 1,959,510	$ 1,866,200	$ -	$ 1,959,510	Safety/Compliance/ Regulatory	N				The SCR is required for compliance with nitrogen dioxide emission rate limits. As the catalyst ages, it deactivates due to poisons and ash fouling and needs to be replaced periodically.	Replacement of a layer of existing catalyst.
5748 -JHC3 Design and Install new Large Particle Ash Screen	5748	$ -	$ 1,485,100	$ 881,800		Equipment Condition	N/A - no spending in 2021					
9194 -JHC1 PJFF Filter Bag Replacement	9194	$ -	$ 1,578,000	$ 1,514,100		Safety/Compliance/ Regulatory	N/A - no spending in 2021					
9196 -JHC3 PJFF Filter Bag & Cleaning Air Manifold Replacement	9196	$ -	$ 3,994,601	$ 3,263,331		Safety/Compliance/ Regulatory	N/A - no spending in 2021					
9655 -JHC1 AQCS Projects	9655	$ 250,000	$ 750,000	$ -	$ -	Equipment Condition	Y		Maintain AQCS equipment reliability to ensure environmental compliance.		JHC1 has air quality control systems (ACI, PJFF) which require periodic equipment replacements and improvements to maintain compliance.	Replace AQCS equipment as required based on condition in 2021-2024. Specific projects to be defined in later years.

Sources												
MEC-CE-545 Att 1						*MEC-CE-1014 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1017*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
		Year										
WorkItemName with ID	**Work ID**	**2021**	**2022**	**2023**	**2024**	**Approval Criteria**	**Unavoidable but Deferable in 2021 (per CE)?**	**Attachment**	**Objective**	**IRR (if available)**	**Problem Statement**	**Scope**
9656 -JHC2 AQCS Projects	9656	$ 250,000	$ 750,000	$ 750,000	$ 750,000	Equipment Condition	Y		Maintain AQCS equipment reliability to ensure environmental compliance.		JHC2 has air quality control systems (SCR, PJFF) which require periodic equipment replacements and improvements to maintain compliance.	Replace AQCS equipment as required based on condition in 2021-2024. Specific projects to be defined in later years.
9692 -JHC3 AQCS Projects	9692	$ 750,000	$ 750,000	$ 750,000	$ 750,000	Equipment Condition	Y		Maintain AQCS equipment reliability to ensure environmental compliance.		JHC3 has extensive air quality control systems (SDA, SCR, PJFF) which require periodic equipment replacements and improvements to maintain compliance.	Replace AQCS equipment as required based on condition in 2021-2024. Specific projects to be defined in later years.
3089 -JHC2 Mill Overhauls (grinding section & gearbox) (H2017 // MC)	3089	$ 400,000	$ -	$ -		Equipment Condition	Y		Overhaul mill to like new condition			Complete disassembly, replace components and reassembly of mill to like new conditions with warranty.
5473 -JHC 1B Condensate Pump Overhaul	5473			$ 220,000		Equipment Condition	N/A - no spending in 2021				The project scope would be to remove the 1B condensate pump and send to the pump repair for cleaning, inspection and repairs and send back for reassembly. The pump base plate will be inspected and machined to level.	
5544 -JHC2 Horz RH Replacement	5544	$ -	$ 150,000	$ 5,053,000	$ 7,898,000	Equipment Condition	N/A - no spending in 2021					
5571 -JHC Centac Air Compressor	5571			$ 694,000		Equipment Condition	N/A - no spending in 2021				Per OEM recommendations, these large air compressors should be overhauled on a 7 to 8 year cycle. This compressor was lasr overhauled in 2011.	
5576 -JHC2 Replace 6 combustion air heat exchanger banks	5576	$ 267,500	$ -	$ -		Equipment Condition	Y	U20697-MEC-CE-035_ATT_42	See Attached			
5577 -JHC2 - Overhaul JHC2 FD Fan Motors	5577	$ 402,000	$ -	$ -		Equipment Condition	N/A - CE has identified as avoidable				Installation of overhauled spare motor as 2B FD Fan motor. Overhaul and rewind of the removed 2B FD fan motor with probable rewind and restack is also included.	Overhaul/Rewind/Restack Campbel U2 Forced Draft Fan Motors and Install Spare
5589 -JHC1 SH Outlet Pendant - partial replacement	5589	$ 200,000	$ 3,490,000	$ -		Economic & Equipment Condition	N/A - CE has identified as avoidable				The JHC1 SH Outlet Pendant experienced a long term overheat failure at an inner lower bend. There have been at least four failures in this area in recent years, and more are expected. Tubing is original, 1961 vintage, and is not unexpected for tubing op	Need funding for engineering / scope development. Plan is to replace roughly half of the tube assemblies in the hottest parts of the furnace. Cost estimates are rough and will need to be validated / updated.
5591 -JHC2 Secondary Air Duct Replace Insulation Lagging and expansion joints	5591	$ 795,000	$ -	$ -		Equipment Condition	Y	U20697-MEC-CE-035_ATT_46	See Attached			
5661 -JHC 1A_1B CDSR Inlet Strainer Taprogge Overhauls	5661	$ -	$ 146,000	$ -		Equipment Condition	N/A - no spending in 2021					
5665 -JHC1 ashpit rebuild	5665		$ 432,000	$ 900,000		Equipment Condition	N/A - no spending in 2021				The ash pit condition is deteriorating and a complete re-build is needed to maintain performance.	
5691 -JHC 3 Replace CO-O2 monitors	5691	$ 1,044,600	$ 904,600	$ -		Safety/Compliance/ Regulatory	Y				the existing monitors only measure O2 and do not adequately represent the flue gas steam. This results in poor combustion and inability to adequately control NOx. Post combustion CO monitoring does not exist on JHC 3.	this project would install post combustion CO and O2 monitors. This project requires a unit outage and engineering to determine the optimal placement of the probes.
5692 -JHC3 SH Terminal Tube Replacement PT-01685	5692		$ -	$ 50,000	$ 6,500,000	Equipment Condition	N/A - no spending in 2021				Replace sections of tubing from furnace up into outlet header. Based on tube sample analysis and oxide scale thickness measurements to be performed.	

Sources												
MEC-CE-545 Att 1						*MEC-CE-1014 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1017*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
		Year										
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5707 -JHC3 Reheater Sootblower	5707	$ 1,250,000	$ -	$ -		Economic	Y		Add sootblowers at upper front of reheater.		Ash buildup on the top/front of the reheater, directly behind the partition wall causes gas/ash laning which leads to localized overheat and erosion conditions. This has caused forced outages in the past. Due to the configuration of the tubing, the amount of collateral damage is typically high when a failure occurs in this area. Additionally, the size of the unit makes detection difficult at the early stages of a leak, leading to significant secondary damage prior to leak identification.	Sootblowers would be mounted in an existing set of manways on the 12th floor of the boiler. These would blow the top/front of the reheater, keeping ash from building to a level that would cause laning and erosion. The sootblowers would need to be configured such that they could be easily disconnected and pulled back, so the opening could still be used as an entry way into the boiler. Current plan is to use existing blowers that were previously purchased but not installed. Sootblowers would need to be capable of indexing so they do not blow on the adjacent partition wall tubing. Additionally, extensive tube shielding would be necessary to protect from erosion by the sootblower.
5708 -JHC3 Redundant Sootblowing Air Compressor	5708	$ 1,200,000	$ -	$ -		Equipment Condition	Y	U20697-MEC-CE-035_ATT_47	See Attached			
5735 -JHC 3 Replace U3 Diesel Generator Controls	5735	$ 106,000	$ -	$ -		Equipment Condition	Y	MEC-CE-1017-Hugo_ATT_2				
5749 -JHC3 Replace Boiler Sidewall Panels	5749			$ 318,600	$ 2,604,000	Equipment Condition	N/A - no spending in 2021				Replace 10 tube panels between the front and rear sidewalls. Exact locations to be dertermined with an internal boiler inspection.	
5750 -JHC3 Replace Boiler Front And Rear Wall Panels	5750			$ 559,700	$ 1,899,100	Equipment Condition	N/A - no spending in 2021				Replace front and rear wall tubes located above the overfire air in the water cannon zones, Tubes have several failure mechanisms, fatigue from water cannons, tube wastage, and membrane cracking due to old age.	
5751 -JHC3 Secondary Air Heater basket and seal replacement	5751			$ 2,425,500	$ 1,484,800	Economic & Equipment Condition	N/A - no spending in 2021				The air preheater baskets and seals are in very poor condition with fouling and heavy erosion. Cold end seals are damaged also from erosion. Last basket replacement was in 2006. Requires at least a 30 day outage for basket replacement.	
9372 -JHC 1A Condensate Pump Overhaul	9372	$ 292,000				Equipment Condition	Y	U20697-MEC-CE-035_ATT_44	See Attachment			
9650 -JHC1 Major Motor and Pump Overhauls	9650	$ 200,000	$ 300,000	$ 300,000	$ 600,000	Equipment Condition	Y		Maintain equipment reliability.		Large pumps and motors require overhauls/rewinds on a regular schedule.	Overhaul 2-5 major motors and/or pumps based on established rebuild schedules and equipment conditions. Specific pumps and motors to be defined at a later date.
9651 -JHC2 Major Motor and Pump Overhauls	9651	$ 200,000	$ 300,000	$ 300,000	$ 300,000	Equipment Condition	Y		Maintain equipment reliability.		Large pumps and motors require overhauls/rewinds on a regular schedule.	Overhaul 2-5 major motors and/or pumps based on established rebuild schedules and equipment conditions. Specific pumps and motors to be defined at a later date.
9653 -JHC1 Balance of Plant Equipment Replacements	9653	$ 150,000	$ 750,000	$ 750,000	$ 1,500,000	Equipment Condition	Y		Maintain reliability of balance of plant systems and equipment.		Each year, a number of balance of plant systems are identified for equipment replacements based on condition. These projects are defined for 2020, but not yet known for 2021-2024.	Replace balance of plant equipment based on condition. Specific equipment to be defined prior to 2021-2023.
9654 -JHC2 Balance of Plant Equipment Replacements	9654	$ 150,000	$ 750,000	$ 750,000	$ 750,000	Equipment Condition	Y		Maintain reliability of balance of plant systems and equipment.		Each year, a number of balance of plant systems are identified for equipment replacements based on condition. These projects are defined for 2020, but not yet known for 2021-2023.	Replace balance of plant equipment based on condition. Specific equipment to be defined prior to 2021-2023.
5478 -Purchase New (Used) Locomotive	5478	$ -				Equipment Condition	N/A - no spending in 2021	Purchased in 2019				
5530 -JHC Site Potable Water Wells 4 and 6	5530		$ 115,800	$ -	$ 122,900	Equipment Condition	N/A - no spending in 2021				Potable water wells and associated pumps should be maintained on a 5-10 year interval.	
5742 -JHC 3 Replace Unit 3 Lake Michigan Intake Screens	5742	$ 1,270,000	$ 619,000	$ -		Safety/Compliance/ Regulatory	Y	U20697-MEC-CE-035_ATT_37	See Attached			

Sources												
MEC-CE-545 Att 1						*MEC-CE-1014 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1017*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
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8616 -JHC 1 Re-align 4160V switchgear with AQCS implementation	8616	$ 1,000,000	$ -	$ -		Equipment Condition	Y	U20697-MEC-CE-035_ATT_26			Current 4160V bus protection for fire or flooding in basement only exists from substation feeds, 199 &799. Start up feed is off aging transformer 7. The new AQCS unit 1 start up transformer 7B has a 4160V winding available for use for the existing plant buses. It is difficult / impossible to perform certain bus maintenance activities due to various taps off the startup transformer.	Currently Unit 1 switchgear is located in the basement. This project would create an intermediate bus that ties in the feed from the new AQCS 7B start up transformer. The new feeds will be designed for higher ratings and the existing gear will be braced for high fault current withstand. Addition of this switchgear allows isolation in the event of a flood, fire, or damage at the 4160V level, vs. 138kV presently. This allows operators to pre-emptively take protective action without going completely black light. This project would result in a simpler one-line and allow for safer and operationally less risky switchgear maintenance.
5457 -JHC FH Install Air Compressors For Train Airup	5457			$ 486,000		Equipment Condition	N/A - no spending in 2021				To prepare empty trains for departure from the site, they must be hooked up to a supply of air and pressurized to 90 PSI to activate the brakes on each car. The railroad requires that the brakes be pressure tested before the empties can leave the site.	
5539 -JHC1 Replace burners corner 1-8	5539	$ -	$ -	$ 100,000	$ 2,700,000	Equipment Condition	N/A - no spending in 2021					
9395 -JHC Dry Ash Landfill Cell Construction & Permitting	9395	$ 5,482,830	$ -	$ 288,570	$ 5,482,830	Safety/Compliance/ Regulatory	N	U20697-MEC-CE-035_ATT_49	See Attached			
9397 -JHC Dry Ash Landfill Closure	9397	$ -	$ -	$ 288,570	$ 1,635,230	Safety/Compliance/ Regulatory	N/A - no spending in 2021					
9528 -JHC Bottom Ash Tanks Chemical Treatment System	9528	$ 250,000				Safety/Compliance/ Regulatory	N	U20697-MEC-CE-035_ATT_32	See Attached			
5480 -JHC FH Replace Fuel Handling Conveyor Belts - JHCAll201508101343	5480	$ 427,000	$ -	$ -		Equipment Condition	Y		This project provides funds to purchase conveyor belt material and to install and hot vulcanize the belting.		The conveyor belts that provide coal to the plant have a finite life and must be monitored regularly and replaced when excessively worn or damaged. This project would allow us to the need materials and install the new belting when necessary, usually during a unit outage or a specific equipment outage. Currently planned replacements are 24A and 26B in 2017, 32B in 2018, 25A and 26A in 2019, 17B and 31B in 2020 and 9A and 10B in 2021. Unexpected loss of any of the conveyor belts can result in extended fueling times for the units (up to 24 hr/day), train demurrage, and possible significant unit derates.	
5543 -JHC1 Mill Overhauls (grinding section & gearbox)	5543	$ 696,000	$ -	$ -		Equipment Condition	Y		Overhaul mill to like new condition			Complete disassembly, replace components and reassembly of mill to like new conditions with warranty.
5545 -JHC2 Overhaul Hydraulic Coupling Rotor	5545	$ 459,000	$ -	$ -		Equipment Condition	Y				Project is to rebuild the spare Hydraulic Coupling rotor removed in 2009 for installation during 2018 periodic outage. Eliminate risk of outage extension due to unforeseen repairs needed to	Rebuild spare Hydraulic Coupling rotor, install in 2018.
5569 -JHC 1 Replace air preheater baskets and seals	5569			$ 1,113,400	$ 942,000	Economic & Equipment Condition	N/A - no spending in 2021				The air preheater baskets have fouling, erosion, the sections of the heating element become dislodged falling through the baskets into the air preheater hoppers causing plugging of the dry fly ash system. Remove and replace all layers of baskets, hot and cold end radial seals, axial seals and circumferential seals. Reset all seal clearances and inspect the rotor post and diaphragms for signs of damage.	
5573 -JHC 2 Overhaul CCWP & Motors	5573	$ 580,000	$ -	$ -		Equipment Condition	N/A - CE has identified as avoidable	U20697-MEC-CE-035_ATT_27	See Attached			

Sources												
MEC-CE-545 Att 1						*MEC-CE-1014 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1017*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
		Year										
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5587 -JHC 1 Replace air and flue gas expansion joints	5587			$ 238,200	$ 650,500	Equipment Condition	N/A - no spending in 2021				Replace air and flue gas expansion joints that are at risk of failing due to age fatigue. The target expansion joints are the economizer outlet, air preheater outlet, Secondary air to overfire air and windbox ducts, FDF outlet duct. Inspections have shown the expansion joints to be in degraded condition and at risk of failure. The best option is to replace the expansion joints. Prioritization is as follows: 1) overfire air and windbox, 2) Air preheater outlet, 3) economizer outlet.	
5594 -JHC2 Main BFP overhaul	5594	$ 359,000	$ -	$ -		Equipment Condition	Y				Unit 2 MBFP is due to be overhauled. Overhaul should be performed prior to failure to minimize repair costs and reduce chances of unplanned lost generation that would result from a pump failure.	Remove MBFP. Send off site to inspect or replace with spare element. Align pump to fluid drive. Correct pipe strain in the piping to the pump. Correct support pads.
5612 -JHC 1 DCS and Simulator Upgrade	5612	$ -	$ -	$ 1,500,000	$ -	Safety/Compliance/ Regulatory	N/A - no spending in 2021	U20697-MEC-CE-035_ATT_15	See Attachment			
5652 -JHC 2 DCS and Simulator Upgrade	5652	$ -	$ -	$ -	$ 1,500,000	Safety/Compliance/ Regulatory	N/A - no spending in 2021	U20697-MEC-CE-035_ATT_17	See Attached			
5663 -JHC 2 2A Condensate Pump Overhaul	5663	$ 210,000	$ -	$ -		Equipment Condition	Y				2A Condensate Pump is past its 10 year recommended overhaul frequency.	Inspection and overhaul of the 2A condensate pump.
5673 -JHC3 HP Turbine Drain Piping Modifications	5673		$ -	$ 653,000	$ 2,535,000	Equipment Condition	N/A - no spending in 2021				JHC3 has experienced pipe failures on the HP turbine and main steam drain piping due to erosion caused by exfoliation of the boiler superheat tubing. Numerous force outage extensions have occurred due to drain line pipe failure during plant start-up.	
5688 -JHC3 RH Drying System	5688	$ -	$ -	$ 75,000	$ 750,000	Economic	N/A - no spending in 2021					
5689 -JHC3 Install Boiler Slag Reducing Coating Front and Rear Walls	5689	$ 53,000	$ 889,000	$ -		Economic	Y					
5693 -JHC3 Mill Complete Overhauls	5693	$ 1,235,000	$ 1,264,800	$ 1,295,300	$ 643,000	Equipment Condition	Y		Overhaul mill to like new condition			Complete disassembly, replace components and reassembly of mill to like new conditions with warranty.
5746 -JHC3 Install Online Dissolved Gas Analysis on GSUs	5746	$ 189,000	$ -	$ -		Equipment Condition	Y					
5752 -JHC3 Static Excitation System Controls Replacement	5752		$ -	$ -	$ 450,000	Equipment Condition	N/A - no spending in 2021				The current EX-2100 is obsolete and GE will be stopping the production of some components in 2019. New digital excitation systems are dependent on electrolytic capacitors which have a shelf life. Upgrade the existing control system portion of the current EX-2100 with an EX-2100e from GE.	
5753 -JHC3 8A HPH Replacement	5753	$ -	$ 650,000	$ 4,739,800	$ 200,000	Economic	N/A - no spending in 2021					
8247 -JHC2 RH Drying	8247	$ -	$ 836,500	$ -		Economic	N/A - no spending in 2021					
8639 -JHC 3 Purchase and install a third auxiliary boiler	8639	$ 686,800	$ 716,100	$ -		Economic & Strategic	Y		Study in 2020 to review the installation of a 3 aux boiler for continued operation of Campbell 3 upon the cessation of Campbell 1&2	U20697-MEC-CE-035_ATT_7 Confidential		In development
9131 -JHC3 BFP A Pump Overhaul	9131				$ 839,790	Equipment Condition	N/A - no spending in 2021				BFP A was last inspected in 2015. The pump vendor says overhauled pumps will typically run for approximately 10 years before an overhaul is required. While this is the recommendation, past performance has dictated overhaul on a varying frequency from 5 years to 10 years. It is therefore system engineering's recommendation that the pumps be evaluated each year after 5 years of service for continued operation.	

Sources

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MEC-CE-545 Att 1						*MEC-CE-1014 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1017*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
9143 -JHC3 H2 Dryer Replacement	9143	$ 83,310	$ -	$ -	$ -	Equipment Condition	Y					
9385 -JHC2 Taprogge A1 & A2 Overhaul	9385	$ 150,000				Equipment Condition	Y	MEC-CE-1017-Hugo_ATT_3				
9525 -JHC3 EHC Fluid Purification System Replacement	9525	$ 81,000	$ -	$ -	$ -	Equipment Condition	Y	MEC-CE-1017-Hugo_ATT_4				
9529 -JHC3 GSU Replacement	9529	$ -	$ -	$ 46,655	$ 933,100	Equipment Condition	N/A - no spending in 2021					
9530 -JHC 3A SBAC	9530	$ -	$ -	$ -	$ 905,107	Equipment Condition	N/A - no spending in 2021					
9671 -JHC Fuel Handling/Infrastructure Replacements	9671	$ 500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	Equipment Condition	Y		Maintain fuel handling reliability.		Due to normal wear, fuel handling equipment requires periodic replacement. Specific conveyor belts and rail road sections are defined for replacement in the next 1-2 years, and additional equipment will be identified for replacement in 2021-2024 based on condition.	Replace conveyor belts, chutes, and other major fuel handling equipment and infrastructure based on condition. Projects to be defined at a later date.
9689 -JHC3 Major Motor and Pump Overhauls	9689	$ -	$ -	$ 400,000	$ 500,000	Equipment Condition	N/A - no spending in 2021					
9690 -JHC3 Balance of Plant Equipment Replacements	9690	$ 200,000	$ 750,000	$ 750,000	$ 750,000	Equipment Condition	Y		Maintain reliability of balance of plant systems and equipment.		Each year, a number of balance of plant systems are identified for equipment replacements based on condition. These projects are defined for 2020, but not yet known for 2021-2024.	Replace balance of plant equipment based on condition. Specific equipment to be defined prior to 2021-2024.
9950 -JHC2 LP Turbine Component Replacement	9950	$ 3,300,000				Economic & Equipment Condition	N	U20697-MEC-CE-035_ATT_18	See Attached	U20697-MEC-CE-035_ATT_5 Confidential		
5481 -JHC Small Valves and Instrumentation-Env and Lab Services	5481	$ 426,000	$ 430,000	$ 435,000	$ 440,000	Equipment Condition	N		Funding to replace valves and instrumentation as needed			
5482 -JHC Small Tools and Equipment	5482	$ 100,000	$ 100,000	$ 100,000	$ 100,000	Equipment Condition	N					
5747 -JHC 3 Boiler Leak Detection System	5747	$ 492,200	$ -	$ -		Economic	Y	U20697-MEC-CE-035_ATT_36	See Attached	U20697-MEC-CE-035_ATT_6 Confidential		
8250 -JHC Small Pumps and Motors	8250	$ 426,000	$ 430,000	$ 435,000	$ 440,000	Equipment Condition	N		Funding to replace pumps and motors as needed			

Avoidable with 2024 or 2025 retirement *(per MEC-CE-544(b))*
Avoidable with 2024 retirement only *(per MEC-CE-544(a))*

Sources

MEC-CE-544 Att 1	Year				*MEC-CE-1015 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1018*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
Work ID	**2021**	**2022**	**2023**	**2024**	**Approval Criteria**	**Unavoidable but Deferable in 2021 (per CE)?**	**Attachment**	**Objective**	**IRR (if available)**	**Problem Statement**	**Scope**
5494 -JHC 3 SDA OandM Maintenance Costs	$ 373,240	$ 373,240	$ 373,240	$ 373,240	Safety/Compliance/ Regulatory	N		Maintain SDA operation and environmental compliance.	N/A	JHC3 SDA equipment requires on-going major maintenance to maintain condition and overall environmental compliance.	JHC3 SDA cleaning and equipment repairs as required based on operating conditions.
5505 -JHC Dry Ash Landfill Engineering Support	$ 224,000	$ 224,000	$ 224,000	$ 224,000	Safety/Compliance/ Regulatory	N	MEC-CE-1018-Hugo_ATT_2		N/A	RCRA requires periodic inspections, groundwater monitoring and other reporting for all of our surface impoundments and landfills.	Perform RCRA groundwater monitoring, reporting, and annual inspections as required by the RCRA rule.
5516 -JHC Landfill - Clean Dry Ash Silos	$ 141,000	$ 144,000	$ -	$ -	Equipment Condition	Y					
5622 -JHC 2 LPA Screen Maintenance	$ -	$ 38,000	$ -	$ -	Safety/Compliance/ Regulatory	N/A - no spending in 2021					
5654 -JHC1 Boiler Testing (MACT Compliance and Burner Tuning)	$ -	$ -	$ -	$ 40,000	Safety/Compliance/ Regulatory	N/A - no spending in 2021					
5694 -JHC3 Boiler Testing-MACT Compliance and Burner Tuning	$ 41,000	$ -	$ 50,000	$ -	Safety/Compliance/ Regulatory	N					
5699 -JHC 3 LPA Screen Maintenance	$ 35,000	$ -	$ -	$ -	Safety/Compliance/ Regulatory	N					
9424 -JHC Groundwater & Corrective Action Monitoring	$ 130,960	$ 130,960	$ 130,960	$ 130,960	Safety/Compliance/ Regulatory	N	MEC-CE-1018-Hugo_ATT_9				
5549 -JHC2 Boiler Testing-MACT Compliance and Burner Tuning	$ 38,000	$ 35,000	$ -	$ -	Safety/Compliance/ Regulatory	N					
9977 -JHC1 HEPS/FAC	$ -	$ -	$ -	$ 300,000	Safety/Compliance/ Regulatory	N/A - no spending in 2021					
9188 -JHC3 Coal Pipe Elbow Replacement	$ 209,000	$ 230,000	$ -	$ -	Equipment Condition	Y	U20697-MEC-CE-035_ATT_28; MEC-CE-1018-Hugo_ATT_8	See attachment	N/A		
5460 -JHC FH Dumper Outage Repairs	$ 185,000	$ 190,000	$ 200,000	$ 200,000	Equipment Condition	Y	MEC-CE-1018-Hugo_ATT_1				
5466 -JHC1 Turbine valve inspection	$ -	$ -	$ -	$ 600,000	Equipment Condition	N/A - no spending in 2021	U20697-MEC-CE-035_ATT_29	See attachment	N/A		
5467 -JHC2 Generator Overhaul-Rewedge-Collector Ring Replacement	$ 3,630,000	$ -	$ -	$ -	Equipment Condition	N	U20697-MEC-CE-035_ATT_19	See attachment	N/A		
5468 -JHC2 Turbine Inspection and Overhaul	$ 2,370,000	$ -	$ -	$ -	Equipment Condition	N	U20697-MEC-CE-035_ATT_39	See attachment	N/A		
5469 -JHC2 Turbine Valve Inspection	$ -	$ -	$ -	$ 110,000	Equipment Condition	N/A - no spending in 2021					
5506 -JHC FH Complex Chute Liner Repairs	$ 150,000	$ 150,000	$ -	$ -	Equipment Condition	Y	MEC-CE-1018-Hugo_ATT_3				
5550 -JHC1 Pulverizer Maintenance - Parts Only Mills-Boiler Plant Equipment	$ 625,000	$ 630,000	$ 643,667	$ 655,167	Equipment Condition	N		Maintain mill conditions. Keep minimum required mills in service to avoid unit derates.	N/A	Coal pulverizers require on-going maintenance to maintain operability.	Purchase required parts to support on-going mill maintenance activities.
5555 -JHC2 Mill Maintenance - Parts Only-Boiler Plant Equipment	$ 310,000	$ 321,000	$ 331,333	$ 341,833	Equipment Condition	N		Maintain mill conditions. Keep minimum required mills in service to avoid unit derates.	N/A	Coal pulverizers require on-going maintenance to maintain operability.	Purchase required parts to support on-going mill maintenance activities.
5596 -JHC1-2 Breaker Maintenance	$ 100,000	$ 100,000	$ -	$ -	Equipment Condition	N/A – CE has identified as avoidable					
5597 -JHC1&2 Medium Voltage Breaker Inspection & Cleaning	$ 60,000	$ 60,000	$ -	$ -	Equipment Condition	N/A – CE has identified as avoidable					
5598 -JHC2 Motor Maintenance	$ 100,000	$ -	$ -	$ -	Equipment Condition	N/A – CE has identified as avoidable					
5601 -JHC2 Pump Maintenance	$ 100,000	$ -	$ -	$ -	Equipment Condition	N/A – CE has identified as avoidable					
5602 -JHC2 Coal Bunker Maintenance	$ 75,000	$ -	$ -	$ -	Equipment Condition	N/A – CE has identified as avoidable					
5628 -JHC1 Install Voting Sudden Pressure Relay System on GSU and SPTs 1A and 1B	$ 62,000	$ -	$ -	$ -	Equipment Condition	N/A – CE has identified as avoidable					

Sources

Work ID	2021	2022	2023	2024	Approval Criteria	Unavoidable but Deferable in 2021 (per CE)?	Attachment	Objective	IRR (if available)	Problem Statement	Scope
MEC-CE-544 Att 1	Year				*MEC-CE-1015 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1018*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
5630 -JHC2 ID fan outlet duct modification construction	$ 70,000	$ -	$ -	$ -	Equipment Condition	Y					
5632 -JHC Unit 2 Screenhouse and Tunnel Cleaning	$ 225,000	$ -	$ -	$ -	Equipment Condition	Y				Zebra mussel growth in the tunnels causes issues with the cooling water equipment and should be cleaned occasionally. Unit 2 tunnel was cleaned in 2011 and 2015, the next opportunity would be 2019.	Contractors to water blast, vac truck, and dispose of approximately 150 yards of zebra mussels.
5637 -JHC3 Periodic Outage Major Maintenance	$ 279,930	$ 279,930	$ 279,930	$ 933,100	Equipment Condition	N				This request is a Major Maintenance request for funding the periodic outage execution based on mid-2018 forecasting, and given the outage schedule.	Forced outage funding remains in Normals and forecasted as funded. This is Periodic outage funding only.
5659 -JHC2 Transformer Base Maintenance	$ 175,000	$ -	$ -	$ -	Equipment Condition	N/A – CE has identified as avoidable					
5669 -JHC1-2 Periodic Outage Major Maintenance	$ 1,512,000	$ 1,248,000	$ 600,000	$ 600,000	Equipment Condition	N				This request is a Major Maintenance request for funding the periodic outage execution based on mid-2018 forecasting, and given the outage schedule.	Forced outage funding remains in Normals and forecasted as funded. This is Periodic outage funding only.
5675 -JHC3 Pulverizer Maintenance - Parts Only Mills-Boiler Plant Equipment	$ 417,999	$ 425,000	$ 425,000	$ 430,000	Equipment Condition	N		Maintain mill conditions. Keep minimum required mills in service to avoid unit derates.		Coal pulverizers require on-going maintenance to maintain operability.	Purchase required parts to support on-going mill maintenance activities.
5696 -JHC3 Outage Base-Boiler and Critical Maintenance	$ 715,000	$ -	$ -	$ 1,000,000	Equipment Condition	N				This scope of work will remove ash/soot that builds up during operation, recertify safety valves to maintain boiler code, perform inspections which result in immediate minor repairs and provide data for future planned repair/replacement scope.	Boiler base funding for boiler tube shielding, ash pit repairs, explosive deslag, backpass sawing/cleaning, code safety valve maintenance, extraction check valve inspection and repair, scaffolding for furnace and other repairs, boiler operating certificate
5715 -JHC No 3 Medium Voltage Breaker Overhauls-Accessory Electric Equipment	$ 60,000	$ 60,000	$ -	$ -	Equipment Condition	Y					
5717 -JHC3 Relay Testing Non-NERC	$ 40,000	$ -	$ -	$ -	Equipment Condition	Y					
5724 -JHC3 Boiler Chemical Cleaning	$ -	$ -	$ -	$ 1,429,000	Equipment Condition	N/A - no spending in 2021				Project covers the cost to chemically clean boiler furnace with contracted labor. Incidence of boiler waterwall tube leak will dramatically increase.	
5733 -JHC Deepwater Intake Screen Inspection	$ 70,000	$ 72,000	$ 72,000	$ 72,000	Safety/Compliance/ Regulatory	N					
5740 -JHC 3 Condenser Vacuum Exhauster Starter Replacement	$ 61,000	$ -	$ -	$ -	Equipment Condition	Y					
5741 -JHC3 Turbine Valve Inspection	$ 1,200,000	$ -	$ -	$ 120,000	Equipment Condition	N	U20697-MEC-CE-035_ATT_22	See attachment	N/A		
9140 -JHC 3A & 3B BFP Turbine Inspection/Overhaul	$ 187,000	$ 1,680,000	$ -	$ -	Equipment Condition	Y	MEC-CE-1018-Hugo_ATT_7				
9200 -JHC 1&2 Stack Platform & Breeching Repair	$ 458,200	$ -	$ -	$ -	Equipment Condition	Y	U20697-MEC-CE-035_ATT_41	See attachment	N/A		
9379 -JHC3 SDA UT & VT Inspections	$ 192,000	$ -	$ -	$ -	Equipment Condition	Y	MEC-CE-1018-Hugo_ATT_9				
9531 -JHC3 Turbine/Generator Inspection	$ -	$ 93,310	$ 373,240	$ 7,931,350	Equipment Condition	N/A - no spending in 2021					
10070 -JHC Electrical Drawing Issues Correction	$ 75,000	$ 75,000	$ -	$ -	Safety/Compliance/ Regulatory	Y					
5606 -JHC1 HEPS - 2019	$ 145,000	$ 100,000	$ 5,000	$ -	Safety/Compliance/ Regulatory	N	MEC-CE-1018-Hugo_ATT_4				
5607 -JHC1 Boiler Safety Programs FAC Inspection 2019	$ 115,000	$ 5,000	$ -	$ -	Safety/Compliance/ Regulatory	N	MEC-CE-1018-Hugo_ATT_5				
5609 -JHC2 HEPS - 2020	$ 5,000	$ -	$ 175,000	$ -	Safety/Compliance/ Regulatory	Y					
5610 -JHC2 Boiler Safety Programs FAC Inspection 2020	$ 5,000	$ -	$ 150,000	$ -	Safety/Compliance/ Regulatory	Y					
5721 -JHC3 HEPS - 2021	$ 85,000	$ -	$ 135,000	$ -	Safety/Compliance/ Regulatory	N					
5722 -JHC3 Boiler Safety Programs FAC Inspection 2021	$ 120,000	$ -	$ 150,000	$ -	Safety/Compliance/ Regulatory	N	MEC-CE-1018-Hugo_ATT_6				
5617 -JHC1 NERC and Non-NERC PRC005 Maintenance	$ -	$ -	$ -	$ 50,000	Safety/Compliance/ Regulatory	N/A - no spending in 2021					
5618 -JHC2 NERC and Non-NERC PRC005 Maintenance	$ -	$ -	$ -	$ 50,000	Safety/Compliance/ Regulatory	N/A - no spending in 2021					

Sources												
MEC-CE-544 Att 1					*MEC-CE-1015 ATT 1*	*MEC-CE-265 Att 1*	*MEC-CE-35 Att 12 2nd revised; MEC-CE-1018*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*	*MEC-CE-35 Att 12 2nd revised*
	Year										
Work ID	**2021**	**2022**	**2023**	**2024**	**Approval Criteria**	**Unavoidable but Deferable in 2021 (per CE)?**	**Attachment**	**Objective**	**IRR (if available)**	**Problem Statement**	**Scope**
9396 -JHC RAP System O&M	$ 110,600	$ 110,600	$ 110,600	$ 110,600	Safety/Compliance/ Regulatory	N					

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CONFIDENTIAL EXHIBIT

Question:

4. For each of Campbell Units 1, 2, and 3, any common areas for Campbell 1&2, and any common areas for the entire Campbell site:
a. Please produce the most recent forecast of the unit's or common area's:
i. non-environmental capital costs
ii. environmental capital costs
iii. major maintenance costs
iv. base O&M costs
Please provide each of these forecasts through 2031; if the forecast does not extend to 2031, please provide the forecasted information through the latest date available.
b. Please identify all capital and major maintenance projects that are estimated to cost more than $200,000 that were performed, are planned, or are under consideration for any of the years 2018 through 2031.
c. For each project identified in subpart b, please
i. Identify the Internal Rate of Return ("IRR") and Present Value Ratio ("PVR");
(a) If the Company has concluded that an IRR or PVR analysis is not required for a specific project, please explain why not, and produce any documents supporting that conclusion.
ii. Produce, in machine-readable electronic format with formulas intact, all workpapers created, used, or relied on in calculating such IRR and PVR; and
iii. Produce the project scope document and/or other written evaluation of the costs and benefits of each identified project.

Response:

Objections of Counsel: Consumers Energy Company objects to this discovery request to the extent that it requests information that is not relevant to this proceeding. Specifically, it requests information beyond the 2021 test year, for which the Company is not requesting recovery in rates in this case.

Further objecting, the request in part b. of this discovery request for "all" capital and major maintenance projects that are estimated to cost more than $200,000 that were performed, are planned, or are under consideration for any of the years 2018 through 2031, is overly broad and unduly burdensome.

Further objecting, the request for documents in part c. of this discovery request is overly broad and would require an extensive review of potentially responsive documents that would be unduly burdensome.

Without waiving these objections, the Company responds as follows:

a. See Attachment U20697-MEC-CE-035_ATT_1 for a forecast of non-environmental capital expenditures, environmental capital expenditures, major maintenance expense and base O&M expense for Campbell Units 1, 2, and 3, any common areas for Campbell 1&2, and any common areas for the entire Campbell site, for the years 2020 through 2021.

b. See Attachment U20697-MEC-CE-035_ATT_2 for a compilation of all capital and major maintenance projects for Campbell Units 1, 2, and 3, any common areas for Campbell 1&2, and any common areas for the entire Campbell site, that are estimated to cost more than $200,000 that were performed, are planned, or are under consideration for any of the years 2018 through 2021.

   i. Refer to Attachment U20697-MEC-CE-035_ATT_2, which identifies the project approval criteria and which projects were supported with an IRR or PVR calculations for any Campbell Units 1, 2, and 3, any common areas for Campbell 1&2, and any common areas for the entire Campbell site, for the years 2018 through 2021.

   As stated in my direct testimony beginning on page 17:

   "The strategic plan for Campbell 3 is predicated on its current planned retirement in 2040 as documented in the approved IRP. The overall long-term objective for Campbell Unit 3 is to maintain economic dispatch from the customer's perspective. The unit provides significant value to customers in both the energy and resource adequacy markets. The capital and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available are included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers."

   Also, beginning on page 15 of my direct testimony:

   "The strategic plan for Campbell Units 1 and 2 is predicated on their current planned retirement in May of 2031 as documented in the approved IRP. The overall long-term objective for Campbell Units 1 and 2 is to maintain economic dispatch from the customer's perspective. The capital and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be considered only if they provide significant value to customers."

   Also, on page 35 of my direct testimony:

   "The Company uses two financial measures, Internal Rate of Return ("IRR") and Present Value Ratio ("PVR"), as a means to evaluate and prioritize projected economic projects within Generation. IRRs and PVRs are calculated using standard Excel formulas. A complex financial model was developed in house that allows the Company to calculate and measure the numerous changes that result when improvements (both O&M and Capital) are made to its rate-based generating units."

ii. See Attachment U20697-MEC-CE-035_ATT_3 Confidential through U20697-MEC-CE-035_ATT_11 Confidential for IRRs. These attachments are referenced on Attachment U20697-MEC-CE-035_ATT_12. These attachments are Confidential and are subject to the Protective Order in Case No. U-20697 and will be provided only to those persons who have signed the nondisclosure certificate pursuant to such Protective Order.

iii. See Attachment U20697-MEC-CE-035_ATT_12 which either provides the project objective, problem statement and scope for each of the approximate 190 projects identified in subpart b or references one of the additional Attachments U20697-MEC-CE-035_ATT_13 through U20697-MEC-CE-035_ATT_49 for the details. Beginning on page 39 of my direct testimony, I discuss the differences between the 2018 and 2019 projected (>$1M) capital projects supported in Case No. U-20134 and the 2018 and 2019 (>$1M) capital projects supported in this case. In addition, please refer to my direct testimony which provides support for all 2020 and 2021 capital projects at the Campbell site with projected capital expenditures greater than $500,000 and 2021 major maintenance projects greater than $225,000.

Scott A. Hugo
April 6, 2020

Director – Generation Asset Strategy

<u>Supplemental Response:</u>

Please see Attachment U20697-MEC-CE-035_ATT_12 Revised, which was updated to include major maintenance and capital projects through 2024 which were greater than $200,000. The revised attachment includes a problem statement and the additional projects are highlighted. The estimates for the projects beyond 2021 are high level order of magnitude projections which may be adjusted during the conceptual approval process which begins in the year prior to beginning project implementation. Previously provided concept approvals, project charters and economic analyses for projects whose implementation begins through the 2021 projected test year apply are applicable to continuing investments beyond 2021.

Scott A. Hugo
May 15, 2020

Director – Generation Asset Strategy

<u>2nd Supplemental Response:</u>

Please see Attachment U20697-MEC-CE-035_ATT_2 Revised, which was updated to reflect revised 2020-2021 capital values for projects which were greater than $200,000.

Scott A. Hugo
May 15, 2020

Director – Generation Asset Strategy

3rd Supplemental Response:

Please see Attachment U20697-MEC-CE-035_ATT_12 Revised, which was updated to reflect revised 2020-2021 capital values for projects which were greater than $200,000.

Scott A. Hugo
May 22, 2020

Director – Generation Asset Strategy

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CONFIDENTIAL EXHIBIT

Question:

5. Refer to line 18 of the "ST-CE-257_ATT_1" spreadsheet, which identifies a scope document and an IRR for the "Low Pressure Turbine Component Replacement" project at Campbell 2.
a. Please confirm that the Work ID for this project is 9950. If not confirmed, please identify the Work ID for this project.
b. Please confirm that cell J18 erroneously identifies "ST-CE-264_ATT_3 Confidential" as the IRR document for this project, and that the IRR analysis for this project is actually "MEC-CE-035_ATT_5 Confidential."
i. If not confirmed, please identify and produce the IRR analysis that corresponds to the Campbell 2 Low Pressure Turbine Replacement project.
c. Please confirm that "ST-CE-257_ATT_55" and "MEC-CE-035_ATT_18" are the same document.
i. If not confirmed, please describe how these documents differ, and identify the most up-to-date project charter for the Campbell 2 Low Pressure Turbine Replacement.
d. Further refer to pages 34-35 of the Hugo Direct Testimony, which discusses different grounds for approving capital investments (safety, regulatory, compliance, economics), and to your response to ST-CE-264(a), which states that ST-CE-257_ATT_1 "identified the attachments for projects which were considered economic for evaluation purposes."
i. Please confirm that the Campbell 2 Low Pressure Turbine Replacement is considered an economic project for evaluation purposes. If not confirmed, please explain why not, and describe in detail how this project was evaluated. Please produce any supporting documentation.
e. According to page 5 of the project charter, MEC-CE-035_ATT_18, the Campbell 2 Low Pressure Turbine Replacement is estimated to cost $3.65 million. The Company's capital expenditure forecasts, however, project a cost of $3.45 million -- $150,000 in 2020, and $3.3 million in 2021. (See workpaper WP-SAH-22 after adding in 2020 values using the pivot table. See also MEC-CE-35 ATT 12 Revised, "2020-24 Capital" tab, line 52.)
i. Please explain this apparent $200,000 discrepancy, and identify the estimated cost and timeline of this project. Please also provide any documentation addressing such discrepancy.
f. Has the Company commenced the bidding process described on page 4 of MEC-CE-035-Hugo_ATT_18?
i. If so, please explain at what stage the Company is in in this process.
ii. If milestone schedule for this project has changed (see p. 4), please provide an updated schedule.
g. Has the Campbell 2 Low Pressure Turbine Replacement received final Company approval for funding? If so, please provide documentation of the approval. If not, when does the Company anticipate approving this project?

Response:

a. Confirmed, Line 18 on the tab labeled SAH-3 P9 of ST-CE-257_ATT_1 is project Work ID 9950.
b. Confirmed.
    i. See response to subpart (b).
c. Confirmed
    i. See response to subpart (c).
d.
    i. Confirmed.
e.
    i. The budget reflected in the Charter is incorrect. The approved budget amount of $3.45 million is the currently planned capital expenditure amount.
f. The Company has not commenced the bidding process described on page 4 of MEC-CE-035-Hugo_ATT_18. The 2021 planned outage for Campbell Unit 2 was originally scheduled to start in March but has been delayed to now start in October. Also reference Attachment U20697-AG-CE-677_ATT_1.
    i. The project team is reevaluating the milestones based upon the new outage schedule.
    ii. At this time, a new milestone schedule has not been developed.
g. This project and its associated capital expenditure amount of $3.65 million has been approved through the Long Term Financial Planning process. No signature document is available.

Scott A. Hugo
May 29, 2020

Director – Generation Asset Strategy

Question:

13. Refer to your response to ST-CE-265(c), which asked for an explanation of whether unavoidable capital and major maintenance projects at Campbell “could be deferred to beyond the test year, but before the assumed retirement date in each scenario,” and for an explanation of why the completion of this project in the test year is to the benefit of ratepayers.”
a. Further refer to the "Capital" and "Major Maintenance" tabs of the "ST-CE-265_ATT_1” spreadsheet. Please explain how the Company determined whether a project could be deferred beyond the projected test year.
b. Further refer to column L of the “Capital” and “Major Maintenance” tabs. Does the Company have any economic or financial analysis supporting its view that ratepayers would benefit from the completion of these deferrable projects in 2021? If so, please provide a copy of such analysis and any underlying workpapers.

Response:

a. Projects which could be deferred beyond the test year were those not tied to a regulatory requirement deadline (SEEG, 316b), emissions compliance (SCR, PJFF), NPDES permit compliance, or CCR compliance. In addition, annual funds for small valve/tool/pump replacements are not deferrable. Finally, critical JH Campbell Unit 2 low-pressure turbine work was determined to be not deferrable due to the increasing risk of blade failure, which would pose a personnel safety hazard and potentially result in catastrophic equipment damage.

   Major Maintenance projects which are not deferable are annual expenses for Air Quality Control Systems maintenance, large particle ash screen maintenance, coal pulverizer maintenance, and periodic outage repairs. Also, Major Maintenance funds required to maintain CCR compliance, boiler certification, 316b compliance, and boiler safety program compliance are not deferrable. In addition, the JH Campbell Unit 3 Turbine Valve Inspection is considered non-deferrable to remain within OEM recommendations for inspection frequency and ensure protection from turbine overspeed events. Lastly, as mentioned above, the JH Campbell Unit 2 Turbine/Generator Inspection and associated work was deemed critical due to past findings on the low-pressure turbine and the extended length of time since the last major inspection (11 years).

   All other projects, both Capital and Major Maintenance, were considered deferrable.

b. The majority of these projects are intended to maintain equipment condition, and therefore not considered “economic” nor evaluated as such. Exceptions are listed below, with associated economic analyses attached. The economic analyses were performed when each project was entered into the financial plan and selected the most beneficial alternative. Attachments U20697-MEC-CE-1020_ATT_1 Confidential through U20697-MEC-CE-1020_ATT_4 Confidential reflect the economic analyses for the following 4 projects, respectively.

5462 JHC2 SAH Replace Baskets and Seals
5689 JHC3 Install Boiler Slag Reducing Coating Front and Rear Walls
8639 JHC3 Purchase and Install a Third Auxiliary Boiler
5747 JHC3 Boiler Leak Detection System

Additionally, the projects below are currently in the engineering phase, and the Company will perform an economic analysis upon completion of the engineering.

5707 JHC3 Reheater Sootblower
5708 Redundant Sootblowing Air Compressor

Scott A. Hugo
May 29, 2020

Director – Generation Asset Strategy

Question:

10. Refer to MEC-CE-545-Hugo_ATT_2 (i.e., the updated WP-SAH-22 workpaper), and to the "2020-24 Capital" tab of MEC-CE-035_ATT_12 Revised. Based on the information provided in these spreadsheets and supporting attachments, there appears to be no IRR, PVR, project charter, scope document, or other supporting document for the following capital projects planned for Campbell in 2021: project nos. 5459, 5537, 5691, 5707, 5735, 9650, 9651, 9653, 9654, 5480, 5543, 5545, 5594, 5663, 5689, 5693, 5746, 9385, 9525, 9671, 9690, 5481, 5482, and 8250.
a. Please confirm that these capital projects planned for 2021 do not currently have supporting documentation.
i. If not confirmed, please identify and provide documentation supporting these projects.
b. For those projects that have an estimated cost of $200,000 or more, and which do not have supporting documentation, please confirm that any rationale/support for these projects would be found in either (i) the Objective, Problem Statement, and Scope columns of the "2020-24 Capital tab" in MEC-CE-035_ATT_12 Revised, or (ii) on pages 52-63 of the Hugo Direct Testimony.
i. If not confirmed, please explain why not, and provide the rationale/support for these projects that was omitted from MEC-CE-035_ATT_12 Revised.

Response:

a. Not confirmed. 5459, 5735, 9385, & 9525 have limited supporting documentation. Attachment U20697-MEC-CE-035_ATT_12 Revised was limited to projects greater than $200,000 so it does not contain the same number of projects listed on U20697-MEC-CE-545-Hugo_ATT_2.
   i. Refer to Attachments U20697-MEC-CE-1017_ATT_1 through U20697-MEC-CE-1017_ATT_4 for concept documents in various stages of approval.

b. Confirmed.
   i. Refer to subpart (b).

Scott A. Hugo
May 29, 2020

Director – Generation Asset Strategy

Question:

11. Refer to the WP-SAH-21 workpaper and to the “2020-24 MM” tab of MEC-CE-035_ATT_12 Revised. Based on the information provided in these spreadsheets and supporting attachments, there appears to be no IRR, PVR, project charter, scope document, or other supporting documents for the following major maintenance projects planned for Campbell in 2021: project nos. 5494, 5505, 5516, 9424, 9188, 5460, 5506, 5550, 5555, 5632, 5637, 5669, 5675, 5696, 9140, 9379, 5606, 5607, 5722 -JHC3 Boiler Safety Programs FAC Inspection 2021, and 9396.
a. Please confirm that these major maintenance projects planned for 2021 do not currently have supporting documentation.
i. If not confirmed, please identify and produce documentation supporting these projects.
b. For those projects that have an estimated cost of $200,000 or more, and which do not have supporting documentation, please confirm that any rationale/support for these projects would be found in either (i) the Objective, Problem Statement, and Scope columns of the “2020-24 MM” tab in MEC-CE-035_ATT_12 Revised, or (ii) on pages 117-20 of the Hugo Direct Testimony.
i. If not confirmed, please explain why not, and provide the rationale/support that was omitted from MEC-CE-035_ATT_12 Revised.

Response:

a. Not confirmed. 5460, 5505, 5506, 5606, 5607, 5722, 9140, 9188, 9379, & 9424 have limited supporting documentation. Attachment U20697-MEC-CE-035_ATT_12 Revised was limited to projects greater than $200,000 so it does not contain the same number of projects listed on WP-SAH-21.
   i. Refer to Attachments U20697-MEC-CE-1018_ATT_1 through U20697-MEC-CE-1017_ATT_10 for scope documents in various stages of approval.

b. Confirmed.
   i. Refer to subpart (b).

Scott A. Hugo
May 29, 2020

Director – Generation Asset Strategy

MEC-93

CONFIDENTIAL EXHIBIT

Generation O&M Summary
2021 Campbell Incremental Capital Expenditures

Case No. U-20697
WP-SAH-23

2024 Early Retirement

Incremental Cost Estimates	2020	2021	2022	2023	2024	2025	Notes
Retire Both Units & Prepare for Demolition	Engineering Procurement, Cost Studies, RMS, ESAs	Detailed Engineering for Separation	Execute Separation, Repowering	Execute Separation, Repowering, Detailed Engr for AD&D	Execute Cold & Dark, Cut & Cap	Abatement & Demolition	
Retire One Unit & Leave Building Operational			Engineering Procurement	Detailed Engr for Cleaning/ Isolation	Clean, Drain Oil, Cut & Cap	Abatement?	
JHC1&2 = JHC3 Incremental Cost	$ 300,000	$ 4,000,000	$ 45,000,000	$ 55,000,000			benchmark against C7 OM&C costs for C&D
JHC1 Only = JHC2 Incremental Cost	$ -	$ -	$ 100,000	$ 500,000	$ 2,500,000		benchmark against C7 OM&C costs for C&D
JHC2 Only = JHC1 Incremental Cost	$ -	$ -	$ 100,000	$ 500,000	$ 3,000,000		benchmark against C7 OM&C costs for C&D

2025 Early Retirement

Incremental Cost Estimates	2020	2021	2022	2023	2024	2025	Notes
Retire Both Units & Prepare for Demolition		Engineering Procurement, Cost Studies, RMS, ESAs	Detailed Engineering for Separation	Execute Separation, Repowering	Execute Separation, Repowering, Detailed Engr for AD&D	Execute Cold & Dark, Cut & Cap	
Retire One Unit & Leave Building Operational				Engineering Procurement	Detailed Engr for Cleaning/ Isolation	Clean, Drain Oil, Cut & Cap	
JHC1&2 = JHC3 Incremental Cost		$ 300,000	$ 4,000,000	$ 45,000,000	$ 55,000,000		benchmark against C7 OM&C costs for C&D
JHC1 Only = JHC2 Incremental Cost		$ -	$ -	$ 100,000	$ 500,000	$ 2,500,000	benchmark against C7 OM&C costs for C&D
JHC2 Only = JHC1 Incremental Cost		$ -	$ -	$ 100,000	$ 500,000	$ 3,000,000	benchmark against C7 OM&C costs for C&D

Question:

19. Refer to the WP-SAH-23 workpaper and Exhibit A-69 (SAH-4).

a. Please provide any workpapers, engineering reports, analyses, cost estimates, or other documents supporting:

i. the incremental costs for 2020-24 listed on lines 8-10

ii. the incremental costs for 2021-25 listed on lines 17-19.

b. If not already explained by the documents produced in response to subpart (a), please provide a detailed explanation for the Company's projection that separating Campbell 1 and 2 from Campbell 3 will cost $114.3 million.

c. Please confirm that the incremental costs shown on lines 8 and 17 of WP-SAH-23 would be still be incurred if Campbell 1 and 2 retired in 2031 (with the costs simply shifting back to later years). If not confirmed, please explain why not.

d. Please confirm that the incremental costs shown on lines 9-10 and 18-19 of WPSAH-23 would be still be incurred if Campbell 1 or 2 individually retired later than 2025 (with the costs simply shifting back to later years). If not confirmed, please explain why not.

Response:

a. The incremental costs were based on an educated order of magnitude estimate of the cost to separate JHC 1&2 from JHC 3 and allow JHC 3 to operate independently. This order of magnitude estimate assumed a worst-case scenario in which a new fueling path to JHC 3 would be required, as the existing coal conveyors route through the JHC 1&2 building to JHC3.

   A separation study is currently underway to develop a more accurate estimate of the cost to separate JHC 1&2 from JHC 3 in support of the 2021 Integrated Resource Plan.

b. As mentioned in subpart (a), the $114.3 million estimate included a new coal handling system from the Campbell coal pile to JHC 3's tripper room, which would require a series of multiple new conveyors and transfer towers routing around the JHC 1&2 building. This high-level estimate also took into account the Company's past experience and knowledge of the costs associated with plant utility separation and re-powering efforts.

c. Confirmed.

d. Confirmed.

Scott A. Hugo
May 1, 2020

Director – Generation Asset Strategy

MEC-96

CONFIDENTIAL EXHIBIT

Question:

22. Refer to your response to MEC-CE-53:

a. Does Consumers intend to update its community transition plan? If so, please identify the associated timeline for an updated transition plan.

b. Please provide a copy of the grant application and/or project scope associated with the Hampton Township EDA grant for which the Company is on the steering committee.

c. Does Consumers intend to develop a formal future use study for the Karn site? If so, what is the current anticipated timeline for such study?

d. What opportunities would be available to Karn employees at a potential solar site constructed on the Karn site?

Response:

a. Yes. Consumers Energy does intend to update its community transition plan in the second half of 2020. The Company plans to further develop and update the plan with drafts expected 3rd to 4th quarter of 2020.

b. See Attachment U20697-MEC-CE-549_ATT_1 for a copy of the Hampton Township EDA grant application and Attachment U20697-MEC-CE-549_ATT_2 for a copy of the confirmation of grant submittal.

c. Consumers Energy is currently planning to solicit proposals and complete a future use study between the 3rd quarter of 2020 and 2nd quarter of 2021.

d. A draft strategy will continue to be developed throughout 2020-2021 which quantifies renewable generation resource opportunities and training requirements within our workforce action planning efforts.

Scott A. Hugo
May 1, 2020

Director – Generation Asset Strategy

Question:

22. Refer to pages 127-32 of the Hugo Direct Testimony, as well as to pages 49-57 of the Direct Testimony of Norman J. Kapala in Case No. U-20165.

a. Further refer to page 50, line 15 through page 52, line 8 of the Kapala Testimony in U- 20165.
i. Please describe and produce the current version of the following documents related to the planned retirement of Karn 1 and 2 in 2023: (a) community transition plan, (b) community communication plan.
ii. Please produce any future-use study, developed by or on behalf of Consumers,
that analyzes potential opportunities to redevelop the Karn site.
b. Please identify actual or projected expenditures for each of the years 2018-21 associated with implementing (i) the community transition plan, and (ii) the future-use study.
c. Please identify and describe in detail any attempt Consumers has made to get community input or engage in public participation planning related to the planned retirement of Karn 1 and 2 in 2023. (Such attempts include, but are not limited to, holding formal or informal public meetings, meeting with local officials, and meeting with community stakeholders). If such attempts have been made, please identify who Consumers has communicated with and when those communications occurred.
d. If not already identified in response to subsection c, please identify any community outreach or communications that have occurred in, or are planned for, 2020 or 2021.
e. Please produce any community benefit agreement that Consumers has entered into related to the planned retirement of Karn 1 and 2 in 2023.

Response:

a.

i. Please see attachments U20697_MEC-CE-053_ATT_1 Confidential and U20697-MEC-CE-053_ATT_2 for the current versions of the community transition plan and the community communication plan. The Confidential information is subject to the Protective Order in Case No. U-20650, and will be provided only to those persons who have signed the nondisclosure certificate pursuant to such Protective Order. Neither of these documents have been updated since they were provided in Case No. U-20165.

ii. No formal study has been conducted to evaluate future-use opportunities for the Karn site. The items below summarize the conceptual opportunities for solar farms at the site.

1. The extended Weadock property (includes the coal yard area) has great potential as an intermodal facility, so we are not evaluating solar development on this portion of the property
2. The southern portion of farmland would support an approximate 90 MW solar site, is a good site with flat-open land, minimal carve-outs, good proximity to HV connections, with some water management concerns.
   a. This site may have other future uses that need to be examined in the future use study
3. The various ash landfills support an approximate solar site of 25 MW, and hopefully brownfield solar gets better special considerations in future years

a. These ash landfills really have no other future use, so solar is a good future use option.

b. Please see Attachment U20697-MEC-CE-053_Att_3 for conceptual Karn 1 & 2 Decommissioning Stakeholder Engagement Budget. No specific projects have related to this attachment have been included in the expenditures for 2018 through 2021. As discussed further in my direct testimony and reflected on my exhibit A-70 (SAH-5) page 1, O&M expense associated with the Karn Separation and Retention plan has been included for the years 2019 through 2021.

c. The Company has supported and will continue to support and participate in public meetings with affected municipalities through the planned retirement date of May 31, 2023. See Attachments U20697-MEC-CE-053_Att_4 and U20697-MEC-CE-053_Att_5 for schedule details for recent (2020) meetings. In addition, the Company assisted Hampton Township with securing an EDA gran, provided matching dollars and is serving on the project steering committee. The Company does not have a long-term schedule for these meetings, it simply supports them as they are scheduled.

d. See subpart (c) of this question.

e. The Company has not entered into a community benefit agreement related to the planned retirement of Karn Units 1 and 2 in May 2023.

Scott A. Hugo
April 6, 2020

Director – Generation Asset Strategy

Karn 1 & 2 Decommissioning Stakeholder Engagement Budget 2020 - 2024	
Category	**Amount**
Local Sponsorships (Tall Ships, food festivals, parades, etc.)	$200,000
Paid Print and Social Media	$35,000
Mailings and publications	$25,000
Events for decommissioning recognition (Steering committee, community tours, last coal shipment)	$95,000
Economic Redevelopment Study	$125,000
Economic Redevelopment Activities (grant matching, implementation support from EDA grant outcome and Karn redevelopment)	$250,000
Total	$730,000.00

Question:

22. Refer to your response to MEC-CE-549.
a. Is the Company consulting with community groups and/or community leaders in updating the Karn community transition plan? If so, please name which community groups/leaders it is consulting with.
b. Does the Company plan to conduct a public forum to receive input on an updated community transition plan?
c. Further refer to your response to MEC-CE-549(c). Please identify who the Company is soliciting proposals from (or plans to solicit proposals from) for the future use study.
d. Further refer to your response to MEC-CE-549(d). Will renewable generation resource opportunities be available to current Karn employees who cannot continue their employment with the Company following the retirement of Karn 1&2?

Response:

a. No. The Company is not consulting with community groups or community leaders in updating the plan.

b. No. The Company does not plan to conduct a public forum to receive input on an updated community transition plan. The Community transition plan is a business confidential document for Company use only.

c. No determination regarding plans for the solicitation of proposals for a future use study has been made.

d. No determination regarding the availability of renewable generation resource availabilities for current Karn employees who cannot continue their employment with the Company following the retirement of Karn 1&2 has been made. However, this opportunity will be taken into consideration as our coal plant retirement strategy moves forward in the years to come.

Scott A. Hugo
May 29, 2020

Director – Generation Asset Strategy

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	U-20697 ALJ Sally Wallace

PROOF OF SERVICE

On the date below, an electronic copy of **the PUBLIC Testimony and Exhibits of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC-NRDC-SC-CUB

Digitally signed by Kimberly Flynn
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